UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 8-K

CURRENT REPORT

PURSUANT TO SECTION 13 OR 15(D) OF THE
SECURITIES EXCHANGE ACT OF 1934

Date of report (Date of earliest event reported): December 10, 2012

CorEnergy Infrastructure Trust, Inc.
(Exact Name of Registrant as Specified in Its Charter)

Maryland	1-33292	20-3431375
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(IRS Employer Identification No.)

4200 W. 115th Street, Suite 210, Leawood, KS	66211
(Address of Principal Executive Offices)	(Zip Code)

(913) 981-1020
(Registrant's Telephone Number, Including Area Code)

(Former Name or Former Address, if Changed Since Last Report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Introductory Note

CorEnergy Infrastructure Trust, Inc. (the “Company”) previously announced that on December 7, 2012, Pinedale Corridor, LP (“Pinedale LP”), a newly formed subsidiary of the Company, entered into a Purchase and Sale Agreement with Ultra Wyoming, Inc., an indirect wholly-owned subsidiary of Ultra Petroleum Corp. (“Ultra Petroleum”). The Purchase and Sale Agreement provides for Pinedale LP’s acquisition, for $225 million in cash, of a system of pipelines and central gathering facilities (the “LGS”) in the Pinedale Anticline in Wyoming (the “Acquisition”). The Purchase and Sale Agreement provides that at the closing of the Acquisition Pinedale LP will enter into a 15-year triple net lease (the “Lease”) relating to the use of the LGS with Ultra Wyoming LGS, LLC, an indirect wholly-owned subsidiary of Ultra Petroleum.

The Company also previously announced that on December 7, 2012, Pinedale LP and Pinedale GP, Inc., a newly formed subsidiary of the Company and the general partner of Pinedale LP (“Pinedale GP”), entered into a Subscription Agreement with Ross Avenue Investments, LLC, an indirect wholly-owned subsidiary of Prudential Financial, Inc. (“Prudential”), pursuant to which Prudential has agreed to fund (the “Co-Investment”) a portion of the Acquisition by investing $30 million in cash in Pinedale LP, and Pinedale GP has agreed to fund a portion of the Acquisition by contributing approximately $134 million in cash to Pinedale LP.

The Company also previously announced that on December 7, 2012, Pinedale LP entered into a $65 million secured Term Credit Agreement (the “Credit Facility”) with KeyBank National Association serving as a lender and the administrative agent on behalf of other participating lenders.

The Company also previously announced on December 10, 2012 that it intends to commence a public offering of 18,500,000 shares of its common stock (the “Offering”) to be made, subject to market and other conditions, pursuant to a prospectus supplement and an accompanying prospectus filed as part of an effective shelf registration statement filed with the Securities and Exchange Commission on Form S-3.

Item 8.01 Other Events

The Company is filing this Current Report on Form 8-K to provide the historical financial statements of Ultra Petroleum and certain proforma financial statements of the Company reflecting the effect of the Acquisition, the Lease, the Co-Investment, the Company’s borrowing $65 million under the Credit Facility and the completion of the Offering.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

SIGNATURES

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

CORENERGY INFRASTRUCTURE TRUST, INC.

Dated: December 10, 2012

By: /s/ David J. Schulte
David J. Schulte
Chief Executive Officer and President

Exhibit Index

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the reference to our firm under the caption "Experts" and to the use of our reports dated February 17, 2012 with respect to the consolidated financial statements of Ultra Petroleum Corp. included and incorporated by reference in the Prospectus Supplement, of CorEnergy Infrastructure Trust, Inc. (formerly known as Tortoise Capital Resources Corporation), to the Registration Statement on Form S-3, as amended (No. 333-176944) and included in CorEnergy Infrastructure Trust, Inc.'s Current Report on Form 8-K dated December 10, 2012, both filed with the Securities and Exchange Commission.

/s/ Ernst & Young LLP

Houston, Texas
December 7, 2012

Exhibit 99.1

INDEX TO ULTRA PETROLEUM CORP. FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Ultra Petroleum Corp.

We have audited the accompanying consolidated balance sheets of Ultra Petroleum Corp. as of December 31, 2011 and 2010, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Ultra Petroleum Corp. at December 31, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, the Company changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements as of December 31, 2009.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Ultra Petroleum Corp.'s internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 17, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 17, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Ultra Petroleum Corp.

We have audited Ultra Petroleum Corp.'s internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Ultra Petroleum Corp.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Ultra Petroleum Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria**.**

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Ultra Petroleum Corp. as of December 31, 2011 and 2010 and the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2011 of Ultra Petroleum Corp. and our report dated February 17, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 17, 2012

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2011	2010	2009
	(Amounts in thousands of U.S. dollars, except per share data)		
Revenues:			
Natural gas sales	$ 982,413	$886,396	$ 601,023
Oil sales	119,383	92,990	65,739
Total operating revenues	1,101,796	979,386	666,762
Expenses:			
Lease operating expenses	51,758	45,938	40,679
Production taxes	97,094	95,914	66,970
Gathering fees	56,511	50,126	45,155
Transportation charges	64,243	64,965	58,011
Depletion, depreciation and amortization	346,394	241,796	201,826
Write-down of proved oil and gas properties	—	—	1,037,000
General and administrative	26,032	24,351	19,772
Total operating expenses	642,032	523,090	1,469,413
Operating income (loss)	459,764	456,296	(802,651)
Other income (expense), net:			
Interest expense	(63,156)	(49,032)	(37,167)
Gain on commodity derivatives	313,732	325,452	146,517
Litigation expense	—	(9,902)	—
Other income (expense), net	532	260	(2,888)
Total other income (expense), net	251,108	266,778	106,462
Income (loss) before income tax provision (benefit)	710,872	723,074	(696,189)
Income tax provision (benefit)	257,670	258,615	(245,136)
Net income (loss)	$ 453,202	$464,459	$ (451,053)
Basic Earnings per Share:			
Net income (loss) per common share — basic	$ 2.97	$ 3.05	$ (2.98)
Fully Diluted Earnings per Share:			
Net income (loss) per common share — fully diluted	$ 2.94	$ 3.01	$ (2.98)
Weighted average common shares outstanding — basic	152,754	152,346	151,367
Weighted average common shares outstanding — fully diluted	154,336	154,253	151,367

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(Amounts in thousands of U.S. dollars, except share data)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 11,307	$ 70,834
Restricted cash	121	98
Oil and gas revenue receivable	88,243	95,142
Joint interest billing and other receivables	82,370	48,561
Derivative assets	230,385	133,991
Inventory	1,164	2,760
Prepaid drilling costs and other current assets	6,330	9,663
Total current assets	419,920	361,049
Oil and gas properties, net, using the full cost method of accounting:		
Proved	3,651,622	2,589,423
Unproved	537,526	486,247
Property, plant and equipment	246,586	149,104
Long-term derivative assets	—	2,066
Deferred financing costs and other	14,051	7,726
Total assets	$4,869,705	$ 3,595,615
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 295,873	$ 210,311
Production taxes payable	62,117	53,382
Interest payable	30,306	26,878
Derivative liabilities	—	718
Deferred tax liabilities	73,380	42,685
Capital cost accrual	209,303	84,042
Total current liabilities	670,979	418,016
Long-term debt	1,903,000	1,560,000
Deferred income tax liabilities	635,009	420,711
Long-term derivative liabilities	—	5,337
Other long-term obligations	67,008	52,575
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Common stock — no par value; authorized — unlimited; issued and outstanding — 152,476,564 and 152,567,813, at December 31, 2011 and 2010, respectively	463,221	426,779
Treasury stock	(14,951)	—
Retained earnings	1,145,439	712,197
Total shareholders' equity	1,593,709	1,138,976
Total liabilities and shareholders' equity	$4,869,705	$ 3,595,615

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(Amounts in thousands of U.S. dollars, except share data)

	Shares Issued and Outstanding	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Treasury Stock	Total Shareholders' Equity
Balances at December 31, 2008	151,233	$346,832	$ 774,117	$ 15,577	$(45,740)	$1,090,786
Stock options exercised	666	1,430	—	—	—	1,430
Employee stock plan grants	85	—	3,397	—	—	3,397
Shares re-issued from treasury	—	(1,430)	(33,785)	—	35,215	—
Net share settlements	(225)	—	(11,293)	—	—	(11,293)
Fair value of employee stock plan grants	—	16,294	—	—	—	16,294
Tax benefit of stock options exercised	—	14,213	—	—	—	14,213
Comprehensive earnings:						
Net earnings		—	(451,053)	—	—	(451,053)
Change in derivative instruments,						
Reclassification of derivative fair value into earnings, net of taxes	—	—	—	(15,577)	—	(15,577)
Total comprehensive earnings						(466,630)
Balances at December 31, 2009	151,759	$377,339	$ 281,383	$ —	$(10,525)	$ 648,197
Stock options exercised	1,206	6,561	—	—	—	6,561
Employee stock plan grants	105	4,841	—	—	—	4,841
Shares re-issued from treasury	—	(587)	(9,938)	—	10,525	—
Net share settlements	(502)	—	(23,707)	—	—	(23,707)
Fair value of employee stock plan grants	—	21,103	—	—	—	21,103
Tax benefit of stock options exercised	—	17,522	—	—	—	17,522
Net income	—	—	464,459	—	—	464,459
Balances at December 31, 2010	152,568	$426,779	$ 712,197	$ —	$ —	$1,138,976
Stock options exercised	672	9,928	—	—	—	9,928
Employee stock plan grants	150	—	—	—	700	700
Shares repurchased	(588)	—	—	—	(20,868)	(20,868)
Shares re-issued from treasury	—	(686)	(4,531)	—	5,217	—
Net share settlements	(325)	—	(15,429)	—	—	(15,429)
Fair value of employee stock plan grants	—	20,988	—	—	—	20,988
Tax benefit of stock options exercised	—	6,212	—	—	—	6,212
Net income	—	—	453,202	—	—	453,202
Balances at December 31, 2011	152,477	$463,221	$1,145,439	$ —	$(14,951)	$1,593,709

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2011	2010	2009
	(Amounts in thousands of U.S. dollars)		
Cash provided by (used in):			
Operating activities:			
Net income (loss) for the period	$ 453,202	$ 464,459	$ (451,053)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depletion and depreciation	346,394	241,796	201,826
Write-down of proved oil and gas properties	—	—	1,037,000
Deferred and current non-cash income taxes	251,206	253,926	(253,966)
Unrealized (gain) loss on commodity derivatives	(100,383)	(208,625)	92,849
Excess tax benefit from stock based compensation	(6,212)	(17,522)	(14,213)
Stock compensation	13,919	12,944	10,901
Other	1,495	734	1,023
Net changes in operating assets and liabilities:			
Restricted cash	(23)	1,583	1,046
Accounts receivable	(26,910)	(31,966)	14,974
Other current assets	17	—	(2,913)
Prepaid expenses and other	(1,291)	(229)	4,268
Other non-current assets	—	(1,176)	(2,905)
Accounts payable and accrued liabilities	86,079	91,982	(38,079)
Production taxes payable	8,735	(7,439)	(596)
Interest payable	3,428	14,867	5,902
Other long-term obligations	433	6,035	(13,638)
Current taxes payable	3,203	3,359	215
Net cash provided by operating activities	1,033,292	824,728	592,641
Investing Activities:			
Acquisition of oil and gas properties	—	(403,806)	—
Oil and gas property expenditures	(1,435,611)	(1,164,389)	(673,518)
Gathering system expenditures	(83,996)	(76,703)	(67,833)
Proceeds from sale of oil and gas properties	5,821	68,420	—
Change in capital cost accrual	125,261	19,826	(56,327)
Restricted cash	—	28,257	(28,257)
Inventory	1,595	1,738	4,024
Purchase of property, plant and equipment	(21,865)	(2,442)	1,300
Net cash used in investing activities	(1,408,795)	(1,529,099)	(820,611)
Financing activities:			
Borrowings on long-term debt	1,257,000	1,000,000	817,000
Payments on long-term debt	(914,000)	(1,260,000)	(827,000)
Proceeds from issuance of Senior Notes	—	1,025,000	235,000
Deferred financing costs	(6,866)	(4,425)	(1,283)
Repurchased shares/net share settlements	(36,298)	(23,707)	(11,293)
Excess tax benefit from stock based compensation	6,212	17,522	14,213
Proceeds from exercise of options	9,928	6,561	1,430
Net cash provided by financing activities	315,976	760,951	228,067
(Decrease) increase in cash during the period	(59,527)	56,580	97
Cash and cash equivalents, beginning of period	70,834	14,254	14,157
Cash and cash equivalents, end of period	$ 11,307	$ 70,834	$ 14,254
SUPPLEMENTAL INFORMATION:			
Cash paid for:			
Interest	$ 88,964	$ 53,291	$ 30,579
Income taxes	$ 7,260	$ 2,537	$ 11,403

See accompanying notes to consolidated financial statements.

(All amounts are expressed in thousands of U.S. dollars (except per share data), unless otherwise noted).

Ultra Petroleum Corp. (the "Company") is an independent oil and natural gas company engaged in the acquisition, exploration, development, and production of oil and natural gas properties. The Company is incorporated under the laws of the Yukon Territory, Canada. The Company's principal business activities are in the Green River Basin of southwest Wyoming and the north-central Pennsylvania area of the Appalachian Basin. In addition, the Company has recently acquired acreage in eastern Colorado's Denver Julesburg Basin.

1. SIGNIFICANT ACCOUNTING POLICIES:

(a) *Basis of presentation and principles of consolidation:* The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. The Company presents its financial statements in accordance with U.S. Generally Accepted Accounting Principles ("GAAP"). All inter-company transactions and balances have been eliminated upon consolidation.

(b) *Cash and cash equivalents:* The Company considers 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) *Property, plant and equipment:* Capital assets are recorded at cost and depreciated using the declining-balance method based on a seven-year useful life. Gathering system expenditures are recorded at cost and depreciated using the straight-line method based on a 30-year useful life.

(e) *Oil and natural gas properties:* On January 6, 2010, the FASB issued an ASU updating oil and gas reserve estimation and disclosure requirements. The ASU amends FASB ASC 932 to align the reserve calculation and disclosure requirements with the requirements in SEC Release No. 33-8995. SEC Release No. 33-8995, amends 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 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. Accordingly, the Company adopted the update to FASB ASC 932 as of December 31, 2009. The implementation of this rule did not result in material additions to the Company's proved reserves included in this report.

The Company uses the full cost method of accounting for exploration and development activities as defined by the Securities and Exchange Commission ("SEC"). Separate cost centers are maintained for each country in which the Company incurs costs. Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. 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 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 the average of prices in effect on the first day of the month for the preceding twelve month period in accordance with SEC Release No. 33-8995. 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 results in a lower depletion, depreciation and amortization ("DD&A") rate 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.

(f) *Inventories:* Materials and supplies inventories are carried at lower of cost or market. 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 December 31, 2011, inventory of $1.2 million primarily includes the cost of pipe and production equipment that will be utilized during the 2012 drilling program.

(g) *Derivative instruments and hedging activities:* Currently, the Company largely relies on commodity derivative contracts to manage its exposure to commodity price risk. These commodity derivative contracts are typically referenced to natural gas index prices as published by independent third parties. Additionally, and from time to time, the Company enters into physical, fixed price forward natural gas sales in order to mitigate its commodity price exposure on a portion of its natural gas production. These fixed price forward gas sales are considered normal sales in the ordinary course of business and outside the scope of FASB ASC Topic 815, Derivatives and Hedging ("FASB ASC 815"). The Company does not offset the value of its derivative arrangements with the same counterparty. (See Note 8).

(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 described in FASB ASC Topic 740, Income Taxes. In addition, the Company recognizes 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 components of basic and diluted net income (loss) per common share:

	December 31, 2011	December 31, 2010	December 31, 2009
Net income (loss)	$453,202	$464,459	$(451,053)
Weighted average common shares outstanding during the period	152,754	152,346	151,367
Effect of dilutive instruments	1,582	1,907	— (1)
Weighted average common shares outstanding during the period including the effects of dilutive instruments	154,336	154,253	151,367
Net income (loss) per common share — basic	$ 2.97	$ 3.05	$ (2.98)
Net income (loss) per common share — fully diluted	$ 2.94	$ 3.01	$ (2.98)
Number of shares not included in dilutive earnings per share that would have been anti-dilutive because the exercise price was greater than the average market price of the common shares	1,030	1,214	— (1)

(1) Due to the net loss for the year ended December 31, 2009, 2.2 million shares for options and restricted stock units 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.

(k) *Accounting for share-based compensation:* The Company measures and recognizes compensation expense for all share-based payment awards made to employees and directors, including employee stock options, based on estimated fair values in accordance with FASB ASC Topic 718, Compensation – Stock Compensation.

(l) *Fair value accounting:* The Company follows FASB ASC Topic 820, Fair Value Measurements and Disclosures (“FASB ASC 820”), which defines fair value, establishes a framework for measuring fair value under GAAP, and expands disclosures about fair value measurements. This statement applies under other accounting topics that require or permit fair value measurements. See Note 9 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:* The Company generally sells natural gas and condensate under both long-term and short-term agreements at prevailing market prices and under multi-year contracts that provide for a fixed price of oil and natural gas. The Company recognizes revenues when the oil and natural gas is delivered, which occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectability is reasonably assured. The Company accounts for oil and natural gas sales using the "entitlements method." Under the entitlements method, revenue is recorded based upon the Company's ownership share of volumes sold, regardless of whether it has taken its ownership share of such volumes. The Company records a receivable or a liability to the extent it receives less or more than its share of the volumes and related revenue. 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. At December 31, 2011 and 2010, the Company had a net natural gas imbalance liability of $1.3 million and $0.9 million, respectively.

Make-up provisions and ultimate settlements of volume imbalances are generally governed by agreements between the Company and its partners with respect to specific properties or, in the absence of such agreements, through negotiation. The value of volumes over- or under-produced can change based on changes in commodity prices. The Company prefers the entitlements method of accounting for oil and natural gas sales because it allows for recognition of revenue based on its actual share of jointly owned production, results in better matching of revenue with related operating expenses, and provides balance sheet recognition of the estimated value of product imbalances.

(o) *Capitalized interest:* Interest is capitalized on the cost of unevaluated gas and oil properties that are excluded from amortization and actively being evaluated as well as on work in process relating to gathering systems that are not currently in service.

(p) *Capital cost accrual:* The Company accrues for exploration and development costs in the period incurred, while payment may occur in a subsequent period.

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

(r) *Recent accounting pronouncements:* In May 2011, the FASB issued ASU No. 2011-04, which amends FASB ASC 820. The amended guidance clarifies many requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements. Additionally, the amendments clarify the FASB's intent about the application of existing fair value measurement requirements. The guidance provided in ASU No. 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The Company does not expect the adoption of this amendment to have a material impact on its consolidated financial statements.

2. OTHER COMPREHENSIVE INCOME:

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

	Year Ended December 31,		
	2011	2010	2009
Net income (loss)	$453,202	$464,459	$(451,053)
Unrealized gain on derivative instruments*	—	—	(24,002)
Tax expense on unrealized gain on derivative instruments	—	—	8,425
Total comprehensive income (loss)	$453,202	$464,459	$(466,630)

* 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 8). The net gain or loss in accumulated other comprehensive income at November 3, 2008 remained on the balance sheet and the respective month's gains or losses were reclassified from accumulated other comprehensive income to earnings as the counterparty settlements affected earnings (January through December 2009). 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.

3. ASSET RETIREMENT OBLIGATIONS:

The Company is required to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of the assets. The following table summarizes the activities for the Company's asset retirement obligations for the years ended:

	December 31,	
	2011	2010
Asset retirement obligations at beginning of period	$28,052	$17,372
Accretion expense	3,088	2,099
Liabilities incurred	10,878	8,564
Liabilities settled	(3)	(17)
Revisions of estimated liabilities	37	34
Asset retirement obligations at end of period	42,052	28,052
Less: current asset retirement obligations	—	—
Long-term asset retirement obligations	$42,052	$28,052

4. OIL AND GAS PROPERTIES:

	December 31, 2011	December 31, 2010
Developed Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$ 5,974,604	$ 4,575,222
Less: Accumulated depletion, depreciation and amortization	(2,322,982)	(1,985,799)
	3,651,622	2,589,423
Unproven Properties:		
Acquisition and exploration costs not being amortized(1),(2)	537,526	486,247
Net capitalized costs — oil and gas properties	$ 4,189,148	$ 3,075,670

On a unit basis, DD&A from continuing operations was $1.41, $1.13 and $1.12 per Mcfe for the years ended December 31, 2011, 2010 and 2009, respectively.

(1) In 2010, a wholly-owned subsidiary of the Company acquired, for $403.8 million in cash, non-producing mineral acres and a small number of producing gas wells in the Pennsylvania Marcellus Shale. Additionally, the Company purchased additional undeveloped acreage in the Marcellus Shale for approximately $63.4 million during 2010.

(2) Interest is capitalized on the cost of unevaluated oil and natural gas properties that are excluded from amortization and actively being evaluated as well as on work in process relating to gathering systems that are not currently in service. For the years ended December 31, 2011 and 2010, total interest on outstanding debt was $93.9 million and $70.2 million, respectively, of which, $30.7 million and $21.2 million, respectively, was capitalized on the cost of unevaluated oil and natural gas properties and work in process relating to gathering systems that are not currently in service.

The Company holds interests in domestic projects in which costs related to these interests are not being depleted pending determination of existence of estimated proved reserves. The Company will continue to assess and allocate the unproven properties over the next several years as proved reserves are established and as exploration dictates whether or not future areas will be developed.

	Total	2011	2010	2009	Prior
Acquisition costs	$ 681,370	$ 69,330	$521,149	$ 36,432	$ 54,459
Exploration costs	22,439	3,364	2,985	2,829	13,261
Capitalized interest	48,084	28,474	19,610	—	—
Sales	(77,498)	(5,821)	(68,420)	(3,257)	—
Less transfers to proved	(136,869)	(44,068)	(44,621)	(36,004)	(12,176)
	$ 537,526	$ 51,279	$430,703	$ —	$ 55,544

5. PROPERTY, PLANT AND EQUIPMENT:

	December 31, 2011			2010
	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
Gathering systems	$226,747	$ (7,736)	$219,011	$141,817
Computer equipment	2,426	(1,401)	1,025	993
Office equipment	444	(335)	109	124
Leasehold improvements	686	(379)	307	151
Land	22,150	—	22,150	2,437
Other	7,777	(3,793)	3,984	3,582
Property, Plant and Equipment, Net	$260,230	$ (13,644)	$246,586	$149,104

Historically, the Company's condensate production was gathered from its Wyoming well locations by tanker trucks and then shipped to other locations for injection into crude oil pipelines or other facilities. During 2010, the Company initiated service on its final two, of four total, central gathering facilities. These facilities are part of the Company's liquids gathering system designed to gather condensate and water from various leases and wells operated by the Company. The condensate and water are transported to central points in the field where condensate can be loaded into trucks or delivered into pipelines for delivery to the Company's customers.

Produced water is disposed of or recycled and re-used. At the end of 2011, more than 80% of the Company's operated condensate production in Wyoming was delivered from the Company's liquids gathering system directly into a pipeline, further reducing truck traffic and improving flow assurance as well as realized pricing.

In Pennsylvania, the Company and its partners continue constructing gas gathering pipelines and facilities, compression facilities and pipeline delivery stations to gather production from its newly completed natural gas wells. Construction on these facilities is expected to continue throughout 2012 allowing the Company to manage its midstream capacity to coincide with increased capacity requirements from its drilling activities. These facilities are gathering systems and related infrastructure, and their construction is expected to continue until the Company's properties in Pennsylvania are fully developed. To date, none of the Company's natural gas production in Pennsylvania has required processing, treating or blending in order to remove natural gas liquids or other impurities and it is anticipated that facilities of this type will not be required in the future to accommodate the Company's production.

6. LONG-TERM LIABILITIES:

	December 31, 2011	December 31, 2010
Bank indebtedness	$ 343,000	$ —
Senior notes	1,560,000	1,560,000
Other long-term obligations	67,008	52,575
	$1,970,008	$1,612,575

Aggregate maturities of debt at December 31, 2011:

2012	2013	2014	2015	2016	Beyond 5 years	Total
$—	$—	$—	$100,000	$405,000	$1,398,000	$1,903,000

Bank indebtedness. The Company (through its subsidiary, Ultra Resources) was a party to a revolving credit facility with a syndicate of banks led by JP Morgan Chase Bank, N.A. which was to mature in April 2012 (the "2007 Credit Agreement"). On October 6, 2011, in anticipation of the upcoming maturity of the 2007 Credit Agreement, the Company, through Ultra Resources (the "Borrower"), replaced the 2007 Credit Agreement in its entirety with a senior unsecured revolving credit facility with JP Morgan Chase Bank, N.A. as administrative agent, and the lenders party thereto (the "2011 Credit Agreement") and repaid all amounts outstanding under the 2007 Credit Agreement with proceeds of loans drawn under the 2011 Credit Agreement.

The 2011 Credit Agreement reflects an increased borrowing capacity as compared to the 2007 Credit Agreement with an initial loan commitment of $1.0 billion (which may be increased up to $1.25 billion at the request of the Borrower and with the lenders' consent), provides for the issuance of letters of credit of up to $250.0 million in aggregate, and matures in October 2016 (which term may be extended for up to two successive one-year periods at the Borrower's request and with the lenders' consent).

Loans under the 2011 Credit Agreement are unsecured and bear interest, at the Borrower's option, based on (A) a rate per annum equal to 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, in either case plus a margin based on a grid of the Borrower's consolidated leverage ratio (for Eurodollar borrowings, 175 basis points per annum as of December 31, 2011). Payment of loans under the 2011 Credit Agreement are guaranteed by Ultra Petroleum Corp. and UP Energy Corporation. The Company also pays commitment fees on the unused commitment under the facility based on a grid of our consolidated leverage ratio.

The 2011 Credit Agreement contains typical and customary representations, warranties, covenants and events of default. The 2011 Credit Agreement includes restrictive covenants requiring the Borrower to maintain a consolidated leverage ratio of no greater than three and one half times to one and, as long as the Company's debt rating is below investment grade, the maintenance of an annual ratio of the net present value of the Company's oil and gas properties to total funded debt of no less than one and one half times to one. At December 31, 2011, the Company was in compliance with all of its debt covenants under the 2011 Credit Agreement.

Senior Notes: The Company's Senior Notes rank pari passu with the Company's 2011 Credit Agreement. Payment of the Senior Notes is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation.

The Senior Notes are pre-payable in whole or in part at any time and are subject to representations, warranties, covenants and events of default customary for a senior note financing. At December 31, 2011, the Company was in compliance with all of its debt covenants under the Senior Notes.

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

7. SHARE BASED COMPENSATION:

The Company sponsors a share based compensation plan: the 2005 Stock Incentive Plan (the "2005 Plan"). The plan is administered by the Compensation Committee of the Board of Directors (the "Committee"). The share based compensation plan is an important component of the total compensation package offered to the Company's key service providers, and reflects the importance that the Company places on motivating and rewarding superior results.

The 2005 Plan was adopted by the Company's Board of Directors on January 1, 2005 and approved by the Company's shareholders on April 29, 2005. The purpose of the 2005 Plan is to foster and promote the long-term financial success of the Company and to increase shareholder value by attracting, motivating and retaining key employees, consultants, and outside directors, and providing such participants with a program for obtaining an ownership interest in the Company that links and aligns their personal interests with those of the Company's shareholders, and thus, enabling such participants to share in the long-term growth and success of the Company. To accomplish these goals, the 2005 Plan permits the granting of incentive stock options, non-statutory stock options, stock appreciation rights, restricted stock, and other stock-based awards, some of which may require the satisfaction of performance-based criteria in order to be payable to participants. The Committee determines the terms and conditions of the awards, including, any vesting requirements and vesting restrictions or forfeitures that may occur. The Committee may grant awards under the 2005 Plan until December 31, 2014, unless terminated sooner by the Board of Directors.

Valuation and Expense Information

	Year Ended December 31,		
	2011	2010	2009
Total cost of share-based payment plans	$21,688	$21,805	$18,872
Amounts capitalized in fixed assets	$ 7,769	$ 8,861	$ 7,971
Amounts charged against income, before income tax benefit	$13,919	$12,944	$10,901
Amount of related income tax benefit recognized in income	$ 4,997	$ 4,595	$ 3,826

Securities Authorized for Issuance Under Equity Compensation Plans

As of December 31, 2011, the Company had the following securities issuable pursuant to outstanding award agreements or reserved for issuance under the Company's previously approved stock incentive plans. Upon exercise, shares issued will be newly issued shares or shares issued from treasury.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options	Weighted Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in the First Column)
Equity compensation plans approved by security holders	1,459	$ 48.29	3,554
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	1,459	$ 48.29	3,554

Changes in Stock Options and Stock Options Outstanding

The following table summarizes the changes in stock options for the three year period ended December 31, 2011:

	Number of Options	Weighted Average Exercise Price (US$)		
Balance, December 31, 2008	4,213	$ 0.25	to	$98.87
Forfeited	(43)	$51.60	to	$78.55
Exercised	(666)	$ 0.25	to	$33.57
Balance, December 31, 2009	3,504	$ 1.49	to	$98.87
Forfeited	(68)	$51.60	to	$76.01
Exercised	(1,206)	$ 1.49	to	$45.95
Balance, December 31, 2010	2,230	$ 3.91	to	$98.87
Forfeited	(99)	$51.60	to	$75.18
Exercised	(672)	$ 3.91	to	$33.57
Balance, December 31, 2011	1,459	$16.97	to	$98.87

The following tables summarize information about the stock options outstanding at December 31, 2011:

	Options Outstanding			
Range of Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value
$16.97 - $19.18	70	2.37	$ 17.44	$ 853
$25.08 - $55.58	637	3.60	$ 38.69	$ 179
$46.05 - $65.04	179	4.53	$ 56.67	$ —
$49.05 - $65.94	373	5.31	$ 54.58	$ —
$51.14 - $98.87	200	6.40	$ 70.51	$ —

	Options Exercisable			
Range of Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value
$16.97 - $19.18	70	2.37	$ 17.44	$ 853
$25.08 - $55.58	637	3.60	$ 38.69	$ 179
$46.05 - $65.04	179	4.53	$ 56.67	$ —
$49.05 - $65.94	373	5.31	$ 54.58	$ —
$51.14 - $98.87	200	6.40	$ 70.51	$ —

The aggregate intrinsic value in the preceding tables represents the total pre-tax intrinsic value, based on the Company's closing stock price of $29.63 on December 30, 2011, which would have been received by the option holders had all option holders exercised their options as of that date. The total number of in-the-money options exercisable as of December 31, 2011 was 0.1 million options.

The following table summarizes information about the weighted-average grant-date fair value of share options:

	2011	2010	2009
Non-vested share options at beginning of year	$30.72	$26.28	$26.18
Non-vested share options at end of year	$ —	$30.72	$26.28
Options vested during the year	$30.73	$23.86	$25.07
Options forfeited during the year	$25.80	$28.36	$29.57

The fair value of stock options that vested during the years ended December 31, 2011, 2010 and 2009 was $6.4 million, $9.8 million and $3.9 million, respectively. The total intrinsic value of stock options exercised during the years ended December 31, 2011, 2010 and 2009 was $21.5 million, $50.7 million and $33.2 million, respectively.

At December 31, 2011, there was no unrecognized compensation cost related to non-vested, employee stock options as all options had fully vested as of December 31, 2011.

PERFORMANCE SHARE PLANS:

Long Term Incentive Plans. The Company offers 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. In 2009, 2010 and 2011, the Compensation Committee (the "Committee") approved an award consisting of performance-based restricted stock units to be awarded to each participant.

For each LTIP award, the Committee establishes performance measures at the beginning of each performance period. 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 as a "target" value which corresponds to the number of shares of the Company's common stock the participant is eligible to receive if the target level for all performance measures is met. In addition, each participant is assigned threshold and maximum award levels in the event that actual performance is below or above target levels. For the 2009, 2010 and 2011 LTIP awards, the Committee established the following performance measures: return on equity, reserve replacement ratio, and production growth.

For the year ended December 31, 2011, the Company recognized $10.7 million in pre-tax compensation expense related to the 2009, 2010 and 2011 LTIP awards of restricted stock units. For the year ended December 31, 2010, the Company recognized $8.6 million in pre-tax compensation expense related to the 2008, 2009 and 2010 LTIP awards of restricted stock units. For the year ended December 31, 2009, the Company recognized $5.8 million in pre-tax compensation expense related to the 2007, 2008 and 2009 LTIP awards of restricted stock units. The amounts recognized during the year ended December 31, 2011 assumes that maximum performance objectives are attained. If the Company ultimately attains these performance objectives, the associated total compensation, estimated at December 31, 2011, for each of the three year performance periods is expected to be approximately $24.1 million, $12.0 million, and $12.1 million related to the 2009, 2010 and 2011 LTIP awards of restricted stock units, respectively. The 2008 LTIP Common Stock Award was paid in shares of the Company's stock to employees during the first quarter of 2011 and totaled $4.3 million (41,443 net shares).

8. DERIVATIVE FINANCIAL INSTRUMENTS:

Objectives and Strategy: 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.

The Company relies on various types of 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's hedging policy limits the amounts of resources hedged to not more than 50% of its forecast production without Board approval. As a result of its hedging activities, the Company may realize prices that are less than or greater than the spot prices that it would have received otherwise. The Company's board approved hedging greater than 50% of the Company's forecast 2011 production.

Commodity Derivative Contracts: 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 provided operational flexibility to curtail gas production in the event of 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 settlements for production months through December 2010. The natural gas reference prices of these commodity derivative contracts are typically referenced to natural gas index prices as published by independent third parties or natural gas futures settlement prices as traded on the NYMEX.

From time to time, 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 FASB ASC 815, Derivatives and Hedging.

Fair Value of Commodity Derivatives: FASB ASC 815 requires that all derivatives be recognized on the balance sheet as either an asset or liability and be measured at fair value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The Company does not apply hedge accounting to any of its derivative instruments. The application of hedge accounting was discontinued by the Company for periods beginning on or after November 3, 2008.

Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at fair value on the balance sheet and the associated unrealized gains and losses are recorded as current expense or income in the income statement. Unrealized gains or losses on commodity derivatives represent the non-cash change in the fair value of these derivative instruments and do not impact operating cash flows on the cash flow statement.

At December 31, 2011, 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 9 for the detail of the asset and liability values of the following derivatives. The Board has approved our hedging greater than 50% of our forecast 2012 production.

Type	Commodity Reference Price	Remaining Contract Period	Volume - MMBTU/Day	Average Price/MMBTU	Fair Value - December 31, 2011
					Asset
Swap	NYMEX	April - October 2012	90,000	$ 5.00	$ 34,310
Swap	NYMEX	Calendar 2012	300,000	$ 5.03	$ 196,075

Subsequent to December 31, 2011 and through February 10, 2012, the Company has entered into 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:

Type	Commodity Reference Price	Remaining Contract Period	Volume - MMBTU/Day	Average Price/MMBTU
Swap	NYMEX	April - December 2012	200,000	$ 3.02

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 years ended December 31, 2011, 2010 and 2009 (refer to Note 2 for details of unrealized gains or losses included in accumulated other comprehensive income in the Consolidated Balance Sheets):

	For the Year Ended December 31,		
	2011	2010	2009
Natural Gas Commodity Derivatives:			
Realized gain on commodity derivatives(1)	$213,349	$116,827	$239,366
Unrealized gain (loss) on commodity derivatives(1)	100,383	208,625	(92,849)
Total gain on commodity derivatives	$313,732	$325,452	$146,517

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

9. FAIR VALUE MEASUREMENTS:

As required by the Fair Value Measurements and Disclosure Topic of the FASB Accounting Standards Codification, we define 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 measurement date and establishes a three level hierarchy for measuring fair value. Fair value measurements are 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 December 31, 2011. The company has no derivative instruments which qualify for cash flow hedge accounting.

	Level 1	Level 2	Level 3	Total
Assets:				
Current derivative asset	$ —	$230,385	$ —	$230,385

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.

Fair 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. The carrying amount of floating-rate debt approximates fair value because the interest rates are variable and reflective of market rates. We use available market data and valuation methodologies to estimate the fair value of our fixed rate debt. This disclosure is presented in accordance with FASB ASC Topic 825, Financial Instruments, and does not impact our financial position, results of operations or cash flows.

	December 31, 2011		December 31, 2010	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-Term Debt:				
5.45% Notes due 2015, issued 2008	$ 100,000	$ 111,475	$ 100,000	$ 108,572
7.31% Notes due 2016, issued 2009	62,000	74,817	62,000	72,153
4.98% Notes due 2017, issued 2010	116,000	128,570	116,000	119,385
5.92% Notes due 2018, issued 2008	200,000	231,091	200,000	212,660
7.77% Notes due 2019, issued 2009	173,000	219,552	173,000	203,051
5.50% Notes due 2020, issued 2010	207,000	229,423	207,000	206,233
4.51% Notes due 2020, issued 2010	315,000	318,925	315,000	284,207
5.60% Notes due 2022, issued 2010	87,000	94,165	87,000	84,818
4.66% Notes due 2022, issued 2010	35,000	34,631	35,000	30,989
5.85% Notes due 2025, issued 2010	90,000	99,022	90,000	87,211
4.91% Notes due 2025, issued 2010	175,000	173,835	175,000	152,064
Credit Facility	343,000	343,000	—	—
	$1,903,000	$2,058,506	$1,560,000	$1,561,343

10. INCOME TAXES:

The consolidated income tax provision is comprised of the following:

	Year Ended December 31, 2011	2010	2009
Current	$ 6,464	$ 4,763	$ 8,830
Current tax benefit on equity compensation	6,212	17,522	14,213
Total current tax	12,676	22,285	23,043
Deferred	244,994	236,330	(268,179)
Total income tax provision (benefit)	$257,670	$258,615	$(245,136)

The income tax provision (benefit) for continuing operations differs from the amount that would be computed by applying the U.S. federal income tax rate of 35% to pretax income as a result of the following:

	Year Ended December 31, 2011	2010	2009
Income tax provision (benefit) computed at the U.S. statutory rate	$248,805	$253,076	$(243,666)
State income tax provision (benefit) net of federal benefit	6,329	3,608	(698)
Canadian net operating loss valuation allowance	—	(677)	—
Tax effect of rate change	4,228	1,939	—
Other, net	(1,692)	669	(772)
	$257,670	$258,615	$(245,136)

The tax effects of temporary differences that give rise to significant components of the Company's deferred tax assets and liabilities for continuing operations are as follows:

	Year Ended December 31, 2011	2010
Deferred tax assets — current:		
Derivative instruments, net	$ —	$ 255
Incentive compensation/other, net	9,329	4,627
Net deferred tax assets — current	$ 9,329	$ 4,882
Deferred tax liabilities — current:		
Derivative instruments, net	$ 82,709	$ 47,567
Net deferred tax liabilities — current	$ 82,709	$ 47,567
Net deferred tax liability — current	$ 73,380	$ 42,685
Deferred tax assets — non-current:		
U.S. federal tax credit carryforwards	13,280	13,714
Capital loss carryforwards	1,929	—
Derivative instruments, net	—	1,161
Incentive compensation/other, net	13,030	14,745
	28,239	29,620
Valuation allowance — Foreign Tax Credit (FTC)	(1,692)	(1,692)
Valuation allowance (Capital loss carryforwards)	(1,929)	—
Net deferred tax assets — non-current	$ 24,618	$ 27,928

	Year Ended December 31, 2011	2010
Deferred tax liabilities — non-current:		
Property and equipment	659,040	448,298
Other	587	341
Net non-current tax liabilities	$ 659,627	$ 448,639
Net non-current tax liability	$ 635,009	$ 420,711

In assessing the realizability of the deferred tax assets, management considers whether it is more likely than not that some or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future taxable income during the periods in which the temporary differences become deductible. Among other items, management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and available tax planning strategies.

The Company did not have any unrecognized tax benefits and there was no effect on our financial condition or results of operations as a result of implementing the standard related to accounting for uncertain tax positions. The amount of unrecognized tax benefits did not change as of December 31, 2011.

It is expected that the amount of unrecognized tax benefits may change in the next twelve months; however Ultra does not expect the change to have a significant impact on the results of operations or the financial position of the Company. The Company currently has no unrecognized tax benefits that if recognized would affect the effective tax rate.

Estimated interest and penalties related to potential underpayment on any unrecognized tax benefits are classified as a component of tax expense in the Consolidated Statement of Operations. The Company has not recorded any interest or penalties associated with unrecognized tax benefits.

The Company files a consolidated federal income tax return in the United States federal jurisdiction and various combined, consolidated, unitary, and separate filings in several states, and international jurisdictions. With certain exceptions, the Company is no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 2008.

As of December 31, 2011, the Company had approximately $11.6 million of U.S. federal alternative minimum tax (AMT) credits available to offset regular U.S. federal income taxes. These AMT credits do not expire and can be carried forward indefinitely. In addition, as of December 31, 2011, the Company has $1.7 million of foreign tax credit carryforwards, none of which expire prior to 2017. However, with the 2007 sale of Sino American Energy, the Company no longer has foreign source income for which to utilize its foreign tax credit carryforwards. Therefore, a valuation allowance has been placed on the remaining foreign tax credit carryforwards.

The Company had an unutilized capital loss carryforward of approximately $5.4 million as of December 31, 2011. The majority of this carryforward expires in 2013. Due to the unpredictability of future capital gains that would allow for the utilization of this carryforward, a valuation allowance has be placed on the full amount of the carryforward.

The Company had Canadian net operating loss carryforwards of approximately $2.7 million as of December 31, 2009. The unexpired portion of the Canadian net operating loss carryforward was fully utilized in 2010, and thus the valuation allowance at December 31, 2009 has been removed and no deferred tax asset related to the Canadian net operating loss exists as of December 31, 2010.

The undistributed earnings of the Company's U.S. subsidiaries are considered to be indefinitely invested outside of Canada. Accordingly, no provision for Canadian income taxes and/or withholding taxes has been provided thereon.

The Company periodically uses derivative instruments designated as cash flow hedges for tax purposes as a method of managing its exposure to commodity price fluctuations. To the extent these hedges are effective, changes in the fair value of these derivative instruments are recorded in Other Comprehensive Income, net of income tax. To the extent these hedges are ineffective, they are marked to market with gains and losses recorded in the statement of operations. At December 31, 2011 and 2010, the Company also recorded a total deferred tax liability of $82.7 million and $46.2 million, respectively, attributable to the unrealized gains and losses recorded in the statement of operations.

11. EMPLOYEE BENEFITS:

The Company sponsors a qualified, tax-deferred savings plan in accordance with provisions of Section 401(k) of the Internal Revenue Code for its employees. Employees may defer up to 100% of their compensation, subject to certain limitations. The Company matches 100% of the employee's contribution up to 5% of compensation, as defined by the plan, along with an employer discretionary contribution of 8%. The expense associated with the Company's contribution was $1.4 million, $1.2 million and $1.1 million for the years ended December 31, 2011, 2010 and 2009, respectively.

12. COMMITMENTS AND CONTINGENCIES:

Transportation contract. The Company is an anchor shipper on REX securing pipeline infrastructure providing sufficient capacity to transport a portion of its natural gas production away from southwest Wyoming and to provide for reasonable basis differentials for its natural gas in the future. REX begins at the Opal Processing Plant in southwest Wyoming and traverses Wyoming and several other states to an ultimate terminus in eastern Ohio. The Company's commitment involves a capacity of 200 MMMBtu per day of natural gas for a term of 10-years commencing in November 2009, 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.

Subsequently, the Company entered into agreements to secure an additional capacity of 50 MMMBtu per day on the REX pipeline system, beginning in January 2012 through December 2018. This additional capacity will provide the Company with the ability to move additional volumes from its producing wells in Wyoming to markets in the eastern U.S.

The Company currently projects that demand charges related to the remaining term of the contract will total approximately $776.3 million.

Drilling contracts. As of December 31, 2011, the Company had committed to drilling obligations with certain rig contractors totaling $60.5 million ($45.5 million due in 2012, $15.0 million due in 2013). The commitments expire in 2013 and were entered into to fulfill the Company's drilling program initiatives in Wyoming.

Office space lease. The Company's maintains office space in Colorado, Texas, Wyoming and Pennsylvania with total remaining commitments for office leases of $2.5 million at December 31, 2011 ($1.0 million in 2012, $1.5 million in 2013 to 2015).

During the years ended December 31, 2011, 2010 and 2009, the Company recognized expense associated with its office leases in the amount of $0.9 million, $0.8 million, and $0.9 million, respectively.

Other. 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, management, after consultation with legal counsel, is of the opinion that the final resolution of all such currently pending or threatened litigation is not likely to have a material adverse effect on the consolidated financial position, results of operations or cash flows of the Company.

13. CONCENTRATION OF CREDIT RISK:

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and commodity derivative contracts associated with the Company's hedging program. The Company's revenues related to natural gas sales are derived principally from a diverse group of companies, including major energy companies, natural gas utilities, oil refiners, pipeline companies, local distribution companies, financial institutions and end-users in various industries.

Concentrations of credit risk with respect to receivables is limited due to the large number of customers and their dispersion across geographic areas. Commodity-based contracts may expose the Company to the credit risk of nonperformance by the counterparty to these contracts. This credit exposure to the Company is diversified primarily among as many as ten major investment grade institutions and will only be present if the reference price of natural gas established in those contracts is less than the prevailing market price of natural gas, from time to time.

The Company maintains credit policies intended to monitor and mitigate the risk of uncollectible accounts receivable related to the sale of natural gas, condensate as well as its commodity derivative positions. The Company performs a credit analysis of each of its customers and counterparties prior to making any sales to new customers or extending additional credit to existing customers. Based upon this credit analysis, the Company may require a standby letter of credit or a financial guarantee. The Company did not have any outstanding, uncollectible accounts for its natural gas or condensate sales, nor derivative settlements sales at December 31, 2011.

A significant counterparty is defined as one that individually accounts for 10% or more of the Company's total revenues during the year. In 2011, the Company had no single customer that represented 10% or more of its total revenues.

14. SUBSEQUENT EVENTS:

FASB ASC Topic 855, Subsequent Events ("FASB ASC 855"), sets forth principles and requirements to be applied to the accounting for and disclosure of subsequent events. FASB ASC 855 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. The FASB issued ASU No. 2010-09, Subsequent Events (FASB ASC 855), Amendments to Certain Recognition and Disclosure Requirement*s,* on February 24, 2010, in an effort to remove some contradictions between the requirements of U.S. GAAP and the SEC's filing rules. The amendments remove the requirement that public companies disclose the date through which their financial statements are evaluated for subsequent events in both issued and revised financial statements. The Company has evaluated the period subsequent to December 31, 2011 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.

15. SUPPLEMENTAL INFORMATION RELATING TO EVENT SUBSEQUENT TO FEBRUARY 17, 2012 (Unaudited):

The Company has evaluated the period subsequent to February 17, 2012 (the date of the Auditor's Report) for events that did not exist but arose after that date and determined that the subsequent event described below should be disclosed in order to prevent the financial statements from being misleading.

During December 2012, the Company entered into a purchase and sale agreement for the sale of its Wyoming liquids gathering system ("LGS") to Pinedale Corridor, LP for $225.0 million, and intends to concurrently enter into a Lease Agreement under a long-term triple net lease. The Lease Agreement provides for an initial term of 15 years and potential successive renewal terms of 5 years or 75% of the then remaining useful life of the LGS at the sole discretion of the Company. Annual rent for the initial term under the Lease Agreement will be a minimum of $20 million (as adjusted annually for changes based on the consumer price index) and a maximum of $27.5 million, with the exact amount being determined depending on changes in the product volume handled by the LGS. During the initial fifteen year term, Pinedale Corridor, LP will receive fixed monthly rental payments of $1,666,667 and variable quarterly rental payments based on the volume of liquid hydrocarbons and water that flowed through the LGS in the prior quarter. The Company's sale leaseback transaction will be treated as a "normal leaseback" and qualifies for sales recognition under the provisions of FASB ASC Topic 840, *Leases*. The Lease will be classified as an operating lease.

16. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED):

	2011				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Revenues from continuing operations	$257,290	$ 280,567	$ 293,141	$ 270,798	$1,101,796
Gain on commodity derivatives	15,635	47,606	114,166	136,325	313,732
Expenses from continuing operations	145,666	151,365	160,543	184,458	642,032
Interest expense	14,590	15,590	15,902	17,074	63,156
Other income (expense), net	20	(4)	(3)	519	532
Income before income tax provision	112,689	161,214	230,859	206,110	710,872
Income tax provision	43,969	57,709	81,713	74,279	257,670
Net income	$ 68,720	$ 103,505	$ 149,146	$ 131,831	$ 453,202
Net income per common share — basic	$ 0.45	$ 0.68	$ 0.98	$ 0.86	$ 2.97
Net income per common share — fully diluted	$ 0.44	$ 0.67	$ 0.97	$ 0.86	$ 2.94

	2010				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Revenues from continuing operations	$273,124	$ 228,388	$ 240,374	$ 237,500	$979,386
Gain (loss) on commodity derivatives	181,351	14,566	150,186	(20,651)	325,452
Expenses from continuing operations	124,260	125,999	128,489	144,342	523,090
Interest expense	11,718	11,437	11,382	14,495	49,032
Litigation expense	—	9,902	—	—	9,902
Other (expense) income , net	151	22	12	75	260
Income before income tax provision	318,648	95,638	250,701	58,087	723,074
Income tax provision	116,272	34,145	88,059	20,139	258,615
Net income	$202,376	$ 61,493	$ 162,642	$ 37,948	$464,459
Net income per common share — basic	$ 1.33	$ 0.40	$ 1.07	$ 0.25	$ 3.05
Net income per common share — fully diluted	$ 1.31	$ 0.40	$ 1.05	$ 0.25	$ 3.01

17. DISCLOSURE ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED):

The following information about the Company's oil and natural gas producing activities is presented in accordance with FASB ASC Topic 932, Oil and Gas Reserve Estimation and Disclosures:

A. OIL AND GAS RESERVES:

On January 6, 2010, the FASB issued an ASU updating oil and gas reserve estimation and disclosure requirements. The ASU amends FASB ASC 932 to align the reserve calculation and disclosure requirements with the requirements in SEC Release No. 33-8995. SEC Release No. 33-8995, amends 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 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.

Our policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the SEC's regulations and GAAP. The Vice President — Reservoir Engineering & Development is primarily responsible for overseeing the preparation of the Company's reserve estimates by our independent engineers, Netherland, Sewell & Associates, Inc. The Vice President – Reservoir Engineering & Development has a Bachelor and Master of Science degree in Petroleum Engineering and is a licensed Professional Engineer with over 17 years of experience. The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

All of the information regarding reserves in this annual report is derived from the report of Netherland, Sewell & Associates, Inc. The report of Netherland, Sewell & Associates, Inc. is included as an Exhibit to this annual report. The principal engineer at Netherland, Sewell & Associates, Inc. responsible for preparing our reserve estimates has a Bachelor of Science degree in Mechanical Engineering and is a licensed Professional Engineer with over 25 years of experience, including significant experience throughout the Rocky Mountain basins.

The Company's proved undeveloped reserves are limited to economic locations that are scheduled in accordance with the Company's current planning and budgeting process. The inventory of bookable locations available to the Company is substantially larger than the amount ultimately included in the Company's year-end reserves. From time to time, the Company may adjust the inventory and schedule of its proved undeveloped locations in response to changes in capital budget, economics, new opportunities in the portfolio or resource availability. The Company has not scheduled any proved undeveloped reserves beyond five years nor does it have any proved undeveloped locations that have been part of its inventory of proved undeveloped locations for over five years.

The determination of oil and natural gas reserves is complex and highly interpretive. Assumptions used to estimate reserve information may significantly increase or decrease such reserves in future periods. The estimates of reserves are subject to continuing changes and, therefore, an accurate determination of reserves may not be possible for many years because of the time needed for development, drilling, testing, and studies of reservoirs.

In estimating proved reserves and future revenue as of December 31, 2011, the Company's independent reserve engineer, Netherland, Sewell & Associates, Inc., used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The reserves were estimated using deterministic methods; these estimates were prepared in accordance with generally accepted petroleum engineering and evaluation principles. Standard engineering and geoscience methods, such as performance analysis, volumetric analysis and analogy, that were considered to be appropriate and necessary to establish reserve quantities and reserve categorization that conform to SEC definitions and guidelines, were also used. In evaluating the information at their disposal, Netherland, Sewell & Associates, Inc. excluded from their consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geoscience. As in all aspects of oil and natural gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, Netherland, Sewell & Associates, Inc.'s conclusions necessarily represent only informed professional judgment.

The following unaudited tables as of December 31, 2011, 2010, and 2009 are based upon estimates prepared by Netherland, Sewell & Associates, Inc. in reports dated February 1, 2012, January 31, 2011, and January 27, 2010, respectively. These are estimated quantities of proved oil and natural gas reserves for the Company and the changes in total proved reserves as of December 31, 2011, 2010 and 2009. All such reserves are located in the Green River Basin in Wyoming and the Appalachian Basin of Pennsylvania.

Since January 1, 2011, no crude oil or natural gas reserve information has been filed with, or included in any report to, any federal authority or agency other than the SEC and the Energy Information Administration ("EIA") of the U.S. Department of Energy. We file Form 23, including reserve and other information, with the EIA.

B. ANALYSES OF CHANGES IN PROVEN RESERVES:

	United States	
	Oil (MBbls)	Natural Gas (MMcf)
Reserves, December 31, 2008	27,007	3,355,788
Extensions, discoveries and additions	5,902	758,659
Production	(1,320)	(172,189)
Revisions	(2,404)	(205,657)
Reserves, December 31, 2009	29,185	3,736,601
Extensions, discoveries and additions	7,369	1,055,047
Production	(1,334)	(205,613)
Revisions	(3,536)	(385,880)
Reserves, December 31, 2010	31,684	4,200,155
Extensions, discoveries and additions	4,592	1,112,147
Production	(1,408)	(236,832)
Revisions	(1,787)	(296,916)
Reserves, December 31, 2011	33,081	4,778,554

	United States	
	Oil (MBbls)	Natural Gas (MMcf)
Proved:		
Developed	11,462	1,412,562
Undeveloped	15,546	1,943,225
Total Proved — 2008	27,007	3,355,788
Developed	11,627	1,541,813
Undeveloped	17,558	2,194,788
Total Proved — 2009	29,185	3,736,601
Developed	11,013	1,678,697
Undeveloped	20,671	2,521,458
Total Proved — 2010	31,684	4,200,155
Developed	11,794	1,973,391
Undeveloped	21,287	2,805,163
Total Proved — 2011	33,081	4,778,554

During 2011, substantially all of our extensions and discoveries in the proved developed category were attributable to wells drilled in 2011, and substantially all of our extensions and discoveries in the proved undeveloped category were attributable to our ongoing drilling activities and its associated effect on our proved undeveloped reserves estimates.

C. STANDARDIZED MEASURE:

The following table sets forth a standardized measure of the estimated discounted future net cash flows attributable to the Company's proved natural gas reserves. Natural gas prices have fluctuated widely in recent years. The calculated weighted average sales prices utilized for the purposes of estimating the Company's proved reserves and future net revenues at December 31, 2011, 2010 and 2009 was $4.035, $4.05 and $3.04 per Mcf, respectively, for natural gas and $88.19, $68.93 and $52.18 per barrel, respectively, for condensate, based upon the average of the price in effect on the first day of the month for the preceding twelve month period.

The future production and development costs represent the estimated future expenditures to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expense was computed by applying statutory income tax rates to the difference between pretax net cash flows relating to the Company's proved reserves and the tax basis of proved properties and available operating loss carryovers.

	As of December 31,		
	2011	2010	2009
Future cash inflows	$ 22,196,913	$ 19,186,072	$ 12,870,816
Future production costs	(6,113,282)	(5,253,509)	(3,916,222)
Future development costs	(4,294,375)	(3,052,843)	(2,249,993)
Future income taxes	(3,340,516)	(3,198,413)	(1,998,114)
Future net cash flows	8,448,740	7,681,307	4,706,487
Discount at 10%	(4,652,684)	(4,155,739)	(2,679,787)
Standardized measure of discounted future net cash flows	$ 3,796,056	$ 3,525,568	$ 2,026,700

The estimate of future income taxes is based on the future net cash flows from proved reserves adjusted for the tax basis of the oil and gas properties but without consideration of general and administrative and interest expenses.

D. SUMMARY OF CHANGES IN THE STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS:

	December 31,		
	2011	2010	2009
Standardized measure, beginning	$3,525,568	$2,026,700	$ 3,017,686
Net revisions of previous quantity estimates	(446,677)	(592,919)	(216,946)
Extensions, discoveries and other changes	1,654,793	1,601,154	782,763
Changes in future development costs	(741,658)	(606,449)	(103,056)
Sales of oil and gas, net of production costs	(896,434)	(787,409)	(513,958)
Net change in prices and production costs	108,108	1,501,002	(1,772,644)
Development costs incurred during the period that reduce future development costs	464,880	404,402	395,092
Accretion of discount	499,358	288,713	444,387
Net changes in production rates and other	(338,982)	297,957	(572,380)
Net change in income taxes	(32,900)	(607,583)	565,756
Aggregate changes	270,488	1,498,868	(990,986)
Standardized measure, ending	$3,796,056	$3,525,568	$ 2,026,700

There are numerous uncertainties inherent in estimating quantities of proved reserves and projected future rates of production and timing of development expenditures, including many factors beyond the control of the Company. The reserve data and standardized measures set forth herein represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. Further, the estimated future net revenues from proved reserves and the present value thereof are based upon certain assumptions, including geologic success, prices, future production levels and costs that may not prove correct over time. Predictions of future production levels are subject to great uncertainty, and the meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based. Historically, oil and natural gas prices have fluctuated widely.

E. COSTS INCURRED IN OIL AND GAS EXPLORATION AND DEVELOPMENT ACTIVITIES:

	Years Ended December 31,		
	2011	2010	2009
United States			
Acquisition costs — unproved properties, net	$ 91,983	$ 472,339	$ 33,176
Exploration	48,998	249,029	102,217
Development	1,372,805	855,110	605,958
Total	$1,513,786	$1,576,478	$741,351

F. RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES:

	Years Ended December 31,		
	2011	2010	2009
United States			
Oil and gas revenue	$1,101,796	$ 979,386	$ 666,762
Production expenses	(205,363)	(191,978)	(152,804)
Depletion and depreciation	(346,394)	(241,796)	(201,826)
Write-down of proved oil and gas properties	—	—	(1,037,000)
Income taxes	(197,464)	(193,692)	254,429
Total	$ 352,575	$ 351,920	$ (470,439)

G. CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES:

	December 31,	
	2011	2010
Developed Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$ 5,974,604	$ 4,575,222
Less: accumulated depletion, depreciation and amortization	(2,322,982)	(1,985,799)
	3,651,622	2,589,423
Unproven Properties:		
Acquisition and exploration costs not being amortized	537,526	486,247
	$ 4,189,148	$ 3,075,670

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
	(Unaudited) (Amounts in thousands, except per share data)			
Revenues:				
Natural gas sales	$ 169,594	$262,147	$ 501,470	$743,898
Oil sales	26,781	30,994	91,319	87,101
Total operating revenues	196,375	293,141	592,789	830,999
Expenses:				
Lease operating expenses	16,741	12,381	45,982	35,853
Production taxes	15,047	25,676	46,634	73,796
Gathering fees	10,274	14,445	46,591	41,363
Transportation charges	21,055	16,061	63,477	48,492
Depletion, depreciation and amortization	86,645	85,795	314,115	238,773
Ceiling test and other impairments	606,827	—	2,475,963	—
General and administrative	6,741	6,185	19,308	19,298
Total operating expenses	763,330	160,543	3,012,070	457,575
Operating (loss) income	(566,955)	132,598	(2,419,281)	373,424
Other income (expense), net:				
Interest expense	(25,369)	(15,902)	(62,414)	(46,082)
(Loss) gain on commodity derivatives	(9,896)	114,166	77,100	177,407
Rig cancellation fees	291	—	(9,220)	—
Other (expense) income, net	(42)	(3)	(27)	14
Total other (expense) income, net	(35,016)	98,261	5,439	131,339
(Loss) income before income tax provision (benefit)	(601,971)	230,859	(2,413,842)	504,763
Income tax provision (benefit)	175	81,713	(708,977)	183,392
Net (loss) income	$(602,146)	$149,146	$(1,704,865)	$321,371
Net (loss) income per common share—basic	$ (3.94)	$ 0.98	$ (11.16)	$ 2.10
Net (loss) income per common share—fully diluted	$ (3.94)	$ 0.97	$ (11.16)	$ 2.08
Weighted average common shares outstanding—basic	152,929	152,817	152,817	152,772
Weighted average common shares outstanding—fully diluted	152,929	154,280	152,817	154,418

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

CONSOLIDATED BALANCE SHEETS

	September 30, 2012 (Unaudited)	December 31, 2011
	(Amounts in thousands of U.S. dollars, except share data)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 59,194	$ 11,307
Restricted cash	121	121
Oil and gas revenue receivable	62,237	88,243
Joint interest billing and other receivables	21,816	82,370
Derivative assets	52,716	230,385
Prepaid drilling costs and other current assets	6,406	7,494
Total current assets	202,490	419,920
Oil and gas properties, net, using the full cost method of accounting:		
Proven	2,095,823	3,651,622
Unproven properties not being amortized	—	537,526
Property, plant and equipment	271,284	246,586
Deferred tax assets	11,586	—
Deferred financing costs and other	12,445	14,051
Total assets	$ 2,593,628	$4,869,705
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 143,751	$ 295,873
Production taxes payable	60,084	62,117
Deferred tax liabilities	11,586	73,380
Interest payable	8,495	30,306
Derivative liabilities	5,470	—
Capital cost accrual	239,671	209,303
Total current liabilities	469,057	670,979
Long-term debt	2,160,000	1,903,000
Deferred tax liabilities	—	635,009
Other long-term obligations	74,174	67,008
Commitments and contingencies		
Shareholders' equity:		
Common stock—no par value; authorized—unlimited; issued and outstanding—152,928,937 and 152,476,564 at September 30, 2012 and December 31, 2011, respectively	470,081	463,221
Treasury stock	(33)	(14,951)
Retained earnings	(579,651)	1,145,439
Total shareholders' equity	(109,603)	1,593,709
Total liabilities and shareholders' equity	$ 2,593,628	$4,869,705

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(Unaudited) (Amounts in thousands of U.S. dollars)	
Cash provided by (used in):		
Operating activities:		
Net (loss) income for the period	$(1,704,865)	$ 321,371
Adjustments to reconcile net (loss) income to cash provided by operating activities:		
Depletion, depreciation and amortization	314,115	238,773
Ceiling test and other impairments	2,475,963	—
Deferred income tax (benefit) provision	(712,363)	176,566
Unrealized loss (gain) on commodity derivatives	183,139	(33,658)
Reduction in (excess) tax benefits from stock based compensation	4,215	(6,441)
Stock compensation	7,830	9,892
Other	1,663	783
Net changes in operating assets and liabilities:		
Restricted cash	—	(11)
Accounts receivable	86,560	(22,329)
Prepaid expenses and other	1,418	(1,927)
Other non-current assets	—	(135)
Accounts payable and accrued liabilities	(151,016)	1,637
Production taxes payable	(2,033)	8,204
Interest payable	(21,811)	8,175
Other long-term obligations	(1,747)	14,432
Taxation payable/receivable, net	(993)	4,460
Net cash provided by operating activities	480,075	719,792
Investing Activities:		
Oil and gas property expenditures	(588,808)	(1,081,450)
Gathering system expenditures	(115,972)	(35,179)
Change in capital cost accrual	30,368	72,568
Inventory	(1,035)	1,212
Purchase of capital assets	(4,133)	(939)
Net cash used in investing activities	(679,580)	(1,043,788)
Financing activities:		
Borrowings on long-term debt	749,000	896,000
Payments on long-term debt	(492,000)	(618,000)
Repurchased shares/net share settlements	(6,550)	(28,625)
(Reduction in) excess tax benefits from stock based compensation	(4,215)	6,441
Proceeds from exercise of options	1,157	9,655
Net cash provided by financing activities	247,392	265,471
Increase (decrease) in cash during the period	47,887	(58,525)
Cash and cash equivalents, beginning of period	11,307	70,834
Cash and cash equivalents, end of period	$ 59,194	$ 12,309

See accompanying notes to consolidated financial statements.

(All amounts 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 development, production, operation, exploration and acquisition of oil and natural 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 and in the north-central Pennsylvania area of the Appalachian Basin.

1. SIGNIFICANT ACCOUNTING POLICIES:

The accompanying financial statements, other than the balance sheet data as of December 31, 2011, are unaudited and were prepared from the Company's records, but do not include all disclosures required by U.S. Generally Accepted Accounting Principles ("GAAP"). Balance sheet data as of December 31, 2011 was derived from the Company's audited financial statements. 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.

Basis of presentation and principles of consolidation: The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. The Company presents its financial statements in accordance with U.S. GAAP. All inter-company transactions and balances have been eliminated upon consolidation.

(a) *Cash and Cash Equivalents:* The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

(b) *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.

(c) *Property, Plant and Equipment:* Capital assets are recorded at cost and depreciated using the declining-balance method based on a seven-year useful life. Gathering system expenditures are recorded at cost and depreciated using the straight-line method based on a 30-year useful life. The gathering system assets are depreciated separately from proven oil and gas properties because they are expected to be used to transport oil and gas not currently included in the Company's proved reserves, including production expected from probable and possible reserves, as well as from third parties.

The Company recognized impairments of $92.5 million during the nine months ended September 30, 2012 related to the decline in fair value as defined in FASB ASC 820 as a result of forecast decreased throughput volumes on its gathering facilities in Pennsylvania due to the decline in commodity prices. These assets are included in Property, Plant and Equipment in the Consolidated Balance Sheets.

(d) *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") Release No. 33-8995, Modernization of Oil and Gas Reporting Requirements ("SEC Release No. 33-8995") and Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 932, Extractive Activities – Oil and Gas ("FASB ASC 932"). 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 Company's proved reserves. 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 the average of prices in effect on the first day of the month for the preceding twelve month period in accordance with SEC Release No. 33-8995. 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 results in a lower depletion, depreciation and amortization ("DD&A") rate 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 Company recorded a $2.4 billion non-cash write-down of the carrying value of its proved oil and natural gas properties for the nine months ended September 30, 2012 as a result of ceiling test limitations, which is reflected with ceiling test and other impairments in the accompanying Consolidated Statements of Operations. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve month period at September 30, 2012 and June 30, 2012 of $2.83 per MMBtu and $3.15 per MMBtu for Henry Hub natural gas, respectively, and $94.97 per barrel and $95.67 per barrel for West Texas Intermediate oil, respectively, adjusted for market differentials.

(e) *Derivative Instruments and Hedging Activities:* Currently, the Company largely relies on commodity derivative contracts to manage its exposure to commodity price risk. These commodity derivative contracts are typically referenced to natural gas index prices as published by independent third parties. Additionally, and from time to time, the Company enters into physical, fixed price forward natural gas sales in order to mitigate its commodity price exposure on a portion of its natural gas production. These fixed price forward natural gas sales are considered normal sales in the ordinary course of business and outside the scope of FASB ASC Topic 815, Derivatives and Hedging ("FASB ASC 815"). The Company does not offset the value of its derivative arrangements with the same counterparty. (See Note 6).

(f) *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 described in FASB ASC Topic 740, Income Taxes. In addition, the Company recognizes 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.

(g) *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.

	Three Months Ended		Nine Months Ended	
	September 30, 2012	September 30, 2011	September 30, 2012	September 30, 2011
	(Share amounts in 000's)			
Net (loss) income	$ (602,146)	$ 149,146	$(1,704,865)	$ 321,371
Weighted average common shares outstanding—basic	152,929	152,817	152,817	152,772
Effect of dilutive instruments	—	1,463	—	1,646
Weighted average common shares outstanding—fully diluted	152,929	154,280	152,817	154,418
Net (loss) income per common share—basic	$ (3.94)	$ 0.98	$ (11.16)	$ 2.10
Net (loss) income per common share—fully diluted	$ (3.94)	$ 0.97	$ (11.16)	$ 2.08
Number of shares not included in dilutive earnings per share that would have been anti-dilutive because the exercise price was greater than the average market price of the common shares	1,373	1,168	1,893	968

(h) *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.

(i) *Accounting for Share-Based Compensation:* The Company measures and recognizes compensation expense for all share-based payment awards made to employees and directors, including employee stock options, based on estimated fair values in accordance with FASB ASC Topic 718, Compensation – Stock Compensation.

(j) *Fair Value Accounting:* The Company follows FASB ASC Topic 820, Fair Value Measurements and Disclosures ("FASB ASC 820"), which defines fair value, establishes a framework for measuring fair value under GAAP, and expands disclosures about fair value measurements. This statement applies under other accounting topics that require or permit fair value measurements. See Note 7 for additional information.

(k) *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 changes in service and equipment costs and changes in the estimated timing of settling asset retirement obligations.

(l) *Revenue Recognition:* The Company generally sells natural gas and condensate under both long-term and short-term agreements at prevailing market prices and under multi-year contracts that provide for a fixed price of oil and natural gas. The Company recognizes revenues when the oil and natural gas is delivered, which occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectability is reasonably assured. The Company accounts for oil and natural gas sales using the "entitlements method." Under the entitlements method, revenue is recorded based upon the Company's ownership share of volumes sold, regardless of whether it has taken its ownership share of such volumes. The Company records a receivable or a liability to the extent it receives less or more than its share of the volumes and related revenue. 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.

Make-up provisions and ultimate settlements of volume imbalances are generally governed by agreements between the Company and its partners with respect to specific properties or, in the absence of such agreements, through negotiation. The value of volumes over- or under-produced can change based on changes in commodity prices. The Company prefers the entitlements method of accounting for oil and natural gas sales because it allows for recognition of revenue based on its actual share of jointly owned production, results in better matching of revenue with related operating expenses, and provides balance sheet recognition of the estimated value of product imbalances.

(m) *Capitalized Interest:* Interest is capitalized on the cost of unevaluated gas and oil properties that are excluded from amortization and actively being evaluated as well as on work in process relating to gathering systems.

(n) *Capital Cost Accrual:* The Company accrues for exploration and development costs and construction of gathering systems in the period incurred, while payment may occur in a subsequent period.

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

(p) *Recent Accounting Pronouncements:* In May 2011, the FASB issued ASU No. 2011-04, which amends FASB ASC 820. The amended guidance clarifies many requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements. Additionally, the amendments clarify the FASB's intent about the application of existing fair value measurement requirements. The guidance provided in ASU No. 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The adoption of this amendment did not have a material impact on the Company's consolidated financial statements.

2. OIL AND GAS PROPERTIES AND EQUIPMENT:

	September 30, 2012	December 31, 2011
Proven Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$ 7,106,729	$ 5,974,604
Less: Accumulated depletion, depreciation and amortization(2)	(5,010,906)	(2,322,982)
	2,095,823	3,651,622
Unproven Properties:		
Acquisition and exploration costs not being amortized(1)	—	537,526
Net capitalized costs—oil and gas properties	$ 2,095,823	$ 4,189,148
Property, Plant and Equipment:		
Gathering Systems(1)	$ 346,520	$ 226,747
Less: Accumulated depreciation(3)	(104,425)	(7,736)
	242,095	219,011
Other Property and Equipment	14,697	11,333
Less: Accumulated depreciation	(7,851)	(5,908)
	6,846	5,425
Land	22,343	22,150
Net capitalized costs—property, plant and equipment	$ 271,284	$ 246,586

(1) For the nine months ended September 30, 2012 and 2011, total interest on outstanding debt was $77.2 million and $69.0 million, respectively, of which, $14.8 million and $22.9 million, respectively, was capitalized on the cost of unevaluated oil and natural gas properties and on work in process relating to gathering systems.

(2) The Company recorded a $2.4 billion non-cash write-down of the carrying value of its proved oil and natural gas properties for the nine months ended September 30, 2012 as a result of ceiling test limitations, which is reflected with ceiling test and other impairments in the accompanying Consolidated Statements of Operations. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve month period at September 30, 2012 and June 30, 2012 of $2.83 per MMBtu and $3.15 per MMBtu for Henry Hub natural gas, respectively, and $94.97 per barrel and $95.67 per barrel for West Texas Intermediate oil, respectively, adjusted for market differentials.

(3) The Company recognized impairments of $92.5 million during the nine months ended September 30, 2012 related to the decline in fair value as defined in FASB ASC 820 as a result of forecast decreased throughput

volumes on its gathering facilities in Pennsylvania due to the decline in commodity prices. These assets are included in Property, Plant and Equipment in the Consolidated Balance Sheets. (See Note 7 for additional information on fair value).

3. LONG-TERM LIABILITIES:

	September 30, 2012	December 31, 2011
Bank indebtedness	$ 600,000	$ 343,000
Senior Notes	1,560,000	1,560,000
Other long-term obligations	74,174	67,008
	$ 2,234,174	$1,970,008

Bank indebtedness: The Company (through its subsidiary, Ultra Resources, Inc.) is a party to a revolving credit facility with a syndicate of banks led by JP Morgan Chase Bank, N.A. (the "Credit Agreement"). The Credit Agreement provides an initial loan commitment of $1.0 billion, which may be increased up to $1.25 billion at the request of the borrower and with the lenders' consent, provides for the issuance of letters of credit of up to $250.0 million in aggregate, and matures in October 2016 (which term may be extended for up to two successive one-year periods at the Borrower's request and with the lenders' consent). At September 30, 2012, the Company had $600.0 million in outstanding borrowings and $400.0 million of available borrowing capacity under the Credit Facility.

Loans under the Credit Agreement are unsecured and bear interest, at the Borrower's option, based on (A) a rate per annum equal to the prime rate or the weighted average fed funds rate on overnight transactions during the preceding business day plus 100 basis points, or (B) a base Eurodollar rate, substantially equal to the LIBOR rate, plus a margin based on a grid of the Borrower's consolidated leverage ratio (200 basis points per annum as of September 30, 2012).

The Credit Agreement contains typical and customary representations, warranties, covenants and events of default. The Credit Agreement includes restrictive covenants requiring the Borrower to maintain a consolidated leverage ratio of no greater than three and one half times to one and, as long as the Company's debt rating is below investment grade, the maintenance of an annual ratio of the net present value of the Company's oil and gas properties to total funded debt of no less than one and one half times to one. At September 30, 2012, the Company was in compliance with all of its debt covenants under the Credit Agreement.

Senior Notes: The Senior Notes rank pari passu with the Company's Credit Agreement. Payment of the Senior Notes is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation. The Senior Notes are pre-payable in whole or in part at any time and are subject to representations, warranties, covenants and events of default customary for a senior note financing. At September 30, 2012, the Company was in compliance with all of its debt covenants under the Master Note Purchase Agreement for Senior Notes.

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

4. SHARE BASED COMPENSATION:

Valuation and Expense Information

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Total cost of share-based payment plans	$ 4,497	$ 5,344	$ 11,513	$ 15,475
Amounts capitalized in fixed assets	$ 1,448	$ 1,898	$ 3,683	$ 5,583
Amounts charged against income, before income tax benefit	$ 3,049	$ 3,446	$ 7,830	$ 9,892
Amount of related income tax benefit recognized in income before valuation allowance	$ 1,265	$ 1,237	$ 3,249	$ 3,551

Changes in Stock Options and Stock Options Outstanding

The following table summarizes the changes in stock options for the nine months ended September 30, 2012 and the year ended December 31, 2011:

	Number of Options (000's)	Weighted Average Exercise Price (US$)		
Balance, December 31, 2010	2,230	$ 3.91	to	$98.87
Forfeited	(99)	$51.60	to	$75.18
Exercised	(672)	$ 3.91	to	$33.57
Balance, December 31, 2011	1,459	$16.97	to	$98.87
Forfeited	(44)	$25.08	to	$75.18
Exercised	(33)	$16.97	to	$25.68
Balance, September 30, 2012	1,382	$16.97	to	$98.87

***Performance Share Plans*:**

Long Term Incentive Plans. The Company offers 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. In 2010, 2011 and 2012, the Compensation Committee (the "Committee") approved an award consisting of performance-based restricted stock units to be awarded to each participant.

For each LTIP award, the Committee establishes performance measures at the beginning of each performance period. Under each LTIP, the Committee establishes a percentage of base salary for each participant which is multiplied by the participant's base salary and individual performance level to derive a Long Term Incentive Value as a "target" value which corresponds to the number of shares of the Company's common stock the participant is eligible to receive if the target level for all performance measures is met. In addition, each participant is assigned threshold and maximum award levels in the event that actual performance is below or above target levels. For LTIP awards in each of 2010, 2011 and 2012, the Committee established the following performance measures: return on equity, reserve replacement ratio, and production growth.

For the nine months ended September 30, 2012, the Company recognized $5.6 million in pre-tax compensation expense related to the 2010, 2011 and 2012 LTIP awards of restricted stock units as compared to $7.5 million during the nine months ended September 30, 2011 related to the 2009, 2010 and 2011 LTIP awards of restricted stock units. The amounts recognized during the nine months ended September 30, 2012 assume that maximum performance objectives are attained under each plan. If the Company ultimately attains these performance objectives, the associated total compensation, estimated at September 30, 2012, for each of the three year performance periods is expected to be approximately $11.5 million, $11.6 million, and $11.9 million related to the 2010, 2011 and 2012 LTIP awards of restricted stock units, respectively. The 2009 LTIP award of restricted stock units was paid in shares of the Company's stock to employees during the first quarter of 2012 and totaled $24.1 million (409,160 net shares).

5. INCOME TAXES:

The Company's overall effective tax rate on pre-tax (loss) income was different than the statutory rate of 35% due primarily to valuation allowances, state income taxes and other permanent differences.

As a result of the tax effect of the ceiling test and other impairments recorded during the nine months ended September 30, 2012, the Company's previously recorded net deferred tax liability fully reversed into a net deferred tax asset. The Company has recorded a full valuation allowance against its net deferred tax asset balance of $279.2 million as of September 30, 2012. This valuation allowance may be reversed in future periods against future taxable income.

6. DERIVATIVE FINANCIAL INSTRUMENTS:

Objectives and Strategy: 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 natural gas production. Historically, prices received for natural gas production have been volatile and unpredictable. Pricing volatility is expected to continue. As a result of its hedging activities, the Company may realize prices that are less than or greater than the spot prices that it would have received otherwise.

The Company relies on various types of 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's hedging policy limits the amounts of resources hedged to not more than 50% of its forecast production without Board approval. The Board approved hedging greater than 50% of the Company's forecast 2012 production.

Fair Value of Commodity Derivatives: FASB ASC 815 requires that all derivatives be recognized on the balance sheet as either an asset or liability and be measured at fair value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The Company does not apply hedge accounting to any of its derivative instruments.

Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at fair value on the balance sheet and the associated unrealized gains and losses are recorded as current income or expense in the Consolidated Statements of Operations. Unrealized gains or losses on commodity derivatives represent the non-cash change in the fair value of these derivative instruments and do not impact operating cash flows on the cash flow statement. See Note 7 for the detail of the fair value of the following derivatives.

Commodity Derivative Contracts: At September 30, 2012, 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. The natural gas reference prices of these commodity derivative contracts are typically referenced to natural gas index prices as published by independent third parties.

Type	Commodity Reference Price	Remaining Contract Period	Volume - MMBTU/ Day	Average Price/ MMBTU	Fair Value - September 30, 2012 Asset
Swap	NYMEX	Oct-Dec 2012	500,000	$ 4.23	$ 41,720
Swap	NYMEX	Oct 2012	90,000	$ 5.00	$ 5,526

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 periods ended September 30, 2012 and 2011:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
Natural Gas Commodity Derivatives:	2012	2011	2012	2011
Realized gain on commodity derivatives(1)	$ 83,433	$ 53,630	$ 260,239	$143,749
Unrealized (loss) gain on commodity derivatives(1)	(93,329)	60,536	(183,139)	33,658
Total (loss) gain on commodity derivatives	$ (9,896)	$114,166	$ 77,100	$177,407

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

7. FAIR VALUE MEASUREMENTS:

As required by FASB ASC 820, the Company 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 measurement date and establishes a three level hierarchy for measuring fair value. Fair value measurements are classified and disclosed in one of the following categories:

Level 1: Quoted prices (unadjusted) in active markets for identical assets and liabilities that the Company has 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 the Company's assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis, as of September 30, 2012. The Company has no derivative instruments which qualify for cash flow hedge accounting.

	Level 1	Level 2	Level 3	Total
Assets:				
Current derivative asset	$ —	$52,716	$ —	$52,716
Liabilities:				
Current derivative liability	$ —	$ 5,470	$ —	$ 5,470

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.

Fair Value of Long-Lived Assets

The Company recognized impairments of $92.5 million during the nine months ended September 30, 2012 related to the decline in fair value as defined in FASB ASC 820 as a result of forecast decreased throughput volumes on its gathering facilities in Pennsylvania due to the decline in commodity prices. These facilities are included in Property, Plant and Equipment in the Consolidated Balance Sheets and were impaired to a fair value of $82.6 million based on the income approach, estimated using Level 3 fair value inputs.

Fair Value of Financial Instruments

The estimated fair value of financial instruments is the estimated amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Consolidated Balance Sheets 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. The Company uses available market data and valuation methodologies to estimate the fair value of its debt. The valuation assumptions utilized to measure the fair value of the Company's debt are considered Level 2 inputs. This disclosure is presented in accordance with FASB ASC Topic 825, Financial Instruments, and does not impact the Company's financial position, results of operations or cash flows.

	September 30, 2012		December 31, 2011	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-Term Debt:				
5.45% Notes due 2015, issued 2008	$ 100,000	$ 109,190	$ 100,000	$ 111,475
7.31% Notes due 2016, issued 2009	62,000	73,344	62,000	74,817
4.98% Notes due 2017, issued 2010	116,000	130,133	116,000	128,570
5.92% Notes due 2018, issued 2008	200,000	235,617	200,000	231,091
7.77% Notes due 2019, issued 2009	173,000	223,101	173,000	219,552
5.50% Notes due 2020, issued 2010	207,000	237,431	207,000	229,423
4.51% Notes due 2020, issued 2010	315,000	333,430	315,000	318,925
5.60% Notes due 2022, issued 2010	87,000	97,218	87,000	94,165
4.66% Notes due 2022, issued 2010	35,000	35,540	35,000	34,631
5.85% Notes due 2025, issued 2010	90,000	101,292	90,000	99,022
4.91% Notes due 2025, issued 2010	175,000	179,071	175,000	173,835
Credit Facility	600,000	600,000	343,000	343,000
	$2,160,000	$2,355,367	$1,903,000	$2,058,506

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:

The Company has evaluated the period subsequent to September 30, 2012 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.

CorEnergy Infrastructure Trust, Inc.
Unaudited Pro Forma Condensed Consolidated Balance Sheet

	At August 31, 2012		
	Historical	Pro Forma Adjustments	Pro Forma Combined
Assets			
Trading securities, at fair value	$ 57,321,502	$ —	$ 57,321,502
Other equity securities, at fair value	19,529,783	—	19,529,783
Leased property, net of accumulated depreciation of $824,066	13,302,783	227,468,914 (1)	240,771,697
Cash and cash equivalents	11,783,529	65,000,000 (2)	18,981,077
		141,790,106 (3)	
		(112,123) (4)	
		(834,191) (5)	
		(225,000,000) (1)	
		(1,177,330) (2)	
		(2,468,914) (1)	
		30,000,000 (3)	
Property and equipment, net of accumulated depreciation of $1,610,766	3,659,240	—	3,659,240
Intangible lease asset, net of accumulated amortization of $267,611	754,176	—	754,176
Prepaid expenses	516,427	(427,398) (3)	89,029
Other assets	4,677,908	(403,762) (5)	4,097,146
		(177,000) (2)	
Deferred leasing costs	—	834,191 (5)	834,191
Deferred debt issuance expenses	—	1,177,330 (2)	1,177,330
Total Assets	$111,545,348	$ 235,669,823	$347,215,171
Liabilities and Stockholders' Equity			
Liabilities			
Line of Credit	$ 125,000	—	$ 125,000
Long-term debt	910,863	65,000,000 (2)	65,910,863
Deferred tax liability	7,388,060	—	7,388,060
Accrued expenses and other liabilities	2,945,571	(34,250) (3)	2,259,174
		(403,762) (5)	
		(177,000) (2)	
		(71,385) (4)	
Total Liablities	11,369,494	64,313,603	75,683,097
Stockholders' Equity			
Stockholders' Equity			
Warrants, no par value: 945,594 issued and outstanding at November 30, 2011 (5,000,000 authorized)	1,370,700	—	1,370,700
Capital stock, non-convertible, $0.001 par value; 9,184,463 and 27,684,463 shares issued and outstanding at August 31, 2012 historical and pro forma, respectively (100,000,000 shares authorized)	9,185	18,500 (3)	27,685
Additional paid-in capital, net of offering costs of $11,228,042 pro forma	92,719,962	141,805,856 (3)	234,098,420
		(427,398) (3)	
Accumulated retained earnings	6,076,007	(40,738) (4)	6,035,269
Total Stockholders' Equity	100,175,854	141,356,220	241,532,074
Non-controlling Interest Stockholders' Equity	—	30,000,000 (3)	30,000,000
Total Stockholder's Equity	100,175,854	171,356,220	271,532,074
Total Liabilities and Stockholders' Equity	$111,545,348	$ 235,669,823	$347,215,171

See accompanying notes to pro forma financial statements

CorEnergy Infrastructure Trust, Inc.
Unaudited Pro Forma Condensed Consolidated Statement of Income

	For the Year Ended November 30, 2011			
	Historical	Pro Forma Adjustments		Pro Forma Combined
Revenue				
Sales Revenue	$ 2,161,723	$ —		$ 2,161,723
Lease Income	1,063,740	20,000,000	(6)	21,063,740
Total Revenue	3,225,463	20,000,000		23,225,463
Expenses				
Cost of Sales (excluding depreciation expense)	1,689,374	—		1,689,374
Management fees, net of expense reimbursements	968,163	2,176,620	(7)	3,144,783
Depreciation expense	364,254	8,748,804	(1)	9,113,058
Operating expenses	196,775	—		196,775
Interest expense	36,508	2,642,743	(2)	2,679,251
Amortization of deferred lease costs		55,613	(5)	55,613
Other expenses	1,440,810	—		1,440,810
Total Expenses	4,695,884	13,623,780		18,319,664
Gain (Loss) from Operations	(1,470,421)	6,376,220		4,905,799
Other Income				
Other income	5,275,421	—		5,275,421
Total Other Income	5,275,421	—		5,275,421
Income before Income Taxes	3,805,000	6,376,220		10,181,220
Income tax expense, net	(882,857)	(2,486,726)	(8)	(3,369,583)
Net Income	$ 2,922,143	$ 3,889,494		6,811,637
Less: Net income attributable to non-controlling interest		1,560,893	(9)	1,560,893
Net income attributable to CorEnergy Stockholders				$ 5,250,744
Earnings Per Common Share attributable to CorEnergy Stockholders:				
Basic and Diluted	$ 0.32			$ 0.19
Weighted Average Shares of Common Stock Outstanding:				
Basic and Diluted	9,159,809	18,500,000	(3)	27,659,809
Dividends declared per share	$ 0.40			

See accompanying notes to pro forma financial statements.

CorEnergy Infrastructure Trust, Inc.
Unaudited Pro Forma Condensed Consolidated Statement of Income

	For the nine months ended August 31, 2012		
	Historical	Pro Forma Adjustments	Pro Forma Combined
Revenue			
Sales Revenue	$ 5,804,894	$ —	$ 5,804,894
Lease Income	1,914,732	15,000,000(6)	16,914,732
Total Revenue	7,719,626	15,000,000	22,719,626
Expenses			
Cost of Sales (excluding depreciation expense)	4,416,947	—	4,416,947
Management fees, net of expense reimbursements	800,397	1,628,348(7)	2,428,745
Asset acquisition expense	238,969	—	238,969
Depreciation expense	740,437	6,561,603(1)	7,302,040
Operating expenses	558,450	—	558,450
Interest expense	69,418	1,982,057(2)	2,051,475
Amortization of deferred leasing costs		41,710(5)	41,710
Other expenses	1,037,679	—	1,037,679
Total Expenses	7,862,297	10,213,718	18,076,015
Gain (loss) from Operations	(142,671)	4,786,282	4,643,611
Other Income			
Other income	20,299,841	—	20,299,841
Total Other Income	20,299,841	—	20,299,841
Income before Income Taxes	20,157,170	4,786,282	24,943,452
Income tax expense, net	(7,444,861)	(1,866,650)(8)	(9,311,511)
Net Income	$12,712,309	$ 2,919,632	$15,631,941
Less: Net income attributable to non-controlling interest		1,170,670(9)	1,170,670
Net income attributable to CorEnergy Stockholders			$14,461,271
Earnings Per Common Share attributable to CorEnergy Stockholders:			
Basic and Diluted	$ 1.38		$ 0.52
Weighted Average Shares of Common Stock Outstanding:			
Basic and Diluted	9,180,776	18,500,000(3)	27,680,776
Dividends declared per share	$ 0.33		

See accompanying notes to pro forma financial statements

CorEnergy Infrastructure Trust, Inc.

Notes to the Unaudited Pro Forma Consolidated Financial Statements

Note 1. Basis of Presentation

These unaudited pro forma condensed consolidated financial statements and underlying pro forma adjustments are based upon currently available information and certain estimates and assumptions made by management; therefore, actual results could differ materially from the pro forma information. However, we believe the assumptions provide a reasonable basis for presenting the significant effects of the transactions noted herein. We believe the pro forma adjustments give appropriate effect to those assumptions and are properly applied in the pro forma information.

Note 2. Pro Forma Adjustments

(1) Represents leased property of $227,468,914 including $2,468,914 of Asset Acquisition Costs capitalized and amortized over the 26 year depreciable life of the leased property. The purchase price allocation is subject to finalization upon completion of asset appraisals. The amount of incremental pro forma depreciation expense is $8,748,804 and $6,561,603 for the year ended November 30, 2011 and the nine month period ended August 31, 2012, respectively.

(2) Represents proceeds from the secured credit facility with KeyBank National Association. The loan is classified as non-current due to interest-only debt service in year 1 of the debt agreement. Outstanding balances under the credit facility will generally accrue interest at a variable annual rate equal to LIBOR plus 3.25%, or 3.462% as of December 7, 2012. The amount of incremental pro forma cash interest expense is $2,250,300 and $1,687,724 for the year ended November 30, 2011 and the nine month period ended August 31, 2012, respectively. Debt issuance costs of $1,177,330 will be paid from the proceeds of the credit facility and will be deferred and amortized over the life of the credit facility. At August 31, 2012, $177,000 of the debt issuance costs was recorded as a component of other assets and accrued expenses and has been reclassified in the pro forma adjustments. The amount of incremental pro forma interest expense related to the amortization of these deferred debt issuance costs is $392,443 and $294,333 for the year ended November 30, 2011 and the nine month period ended August 31, 2012, respectively.

Funding of the credit facility is conditioned on the contribution of the proceeds of this offering to our wholly-owned subsidiary, Pinedale LP and the receipt by Pinedale LP of the co-investment funds from Prudential. A 1/8% variance in interest rates would impact pro forma net income by $81,250 and $60,938 for the pro forma year ended November 30, 2011 and the none month period ended August 31, 2012, respectively.

(3) In connection with this offering, it is expected that the Company will issue 18,500,000 shares of $0.001 par value common stock at an assumed public offering price of $8.25 (the last reported sale price of our common stock on the NYSE on December 7, 2012). Equity proceeds of $141,396,958 reflected as an increase to stockholders' equity are net of $11,228,042 of equity issuance costs and private equity placement fees. At August 31, 2012, $427,398 of the equity issuance costs were recorded as a component of prepaid expenses. Of this total amount, $393,148 were paid as of August 31, 2012 and $34,250 was accrued. These amounts have been reclassified in the pro forma adjustments. In conjunction with the Acquisition, Prudential will contribute $30,000,000 of private equity to Pinedale LP in exchange for an approximate 18% limited partner interest in Pinedale LP.

(4) Represents the use of proceeds to pay asset acquisition expenses of $138,169 net of the tax impact of $26,046 calculated at a statutory rate of 39% that result from these expenses. At August 31, 2012, asset acquisition expenses totaled $238,969, of which $71,385 were accrued. The $66,784 that was not expensed and accrued at August 31, 2012 is reflected as a reduction in accumulated retained earnings, net of the tax impact of $26,046 calculated at a statutory rate of 39%.

(5) Represents the use of proceeds to pay $834,191 of leasing and related costs that qualify for deferral to be capitalized and amortized over the 15-year lease term. Of this amount, $403,762 was accrued and reflected in the balance sheet at August 31, 2012 as a component of other assets and accrued expenses. The amount of incremental pro forma deferred leasing cost expense is $55,613 and $41,710 for the year ended November 30, 2011 and the nine month period ended August 31, 2012, respectively.

(6) Represents lease income from Lease Agreement. The amount of incremental pro forma lease income is $20,000,000 and $15,000,000 for the year ended November 30, 2011 and the nine month period ended August 31, 2012, respectively.

(7) Represents the adjustment for a 1.0% annual management fee payable to our related party, external adviser, Corridor InfraTrust Management, LLC, on approximately $217,000,000 of additional managed assets. Such fee results in an expense of $2,176,620 and $1,628,348 for the year ended November 30, 2011 and the nine month period ended August 31, 2012, respectively.

(8) Reflects the income tax expense related to the effect of the pro forma adjustments at a combined estimated federal and state (net of federal benefit) statutory income tax rate of 39.0%.

(9) Net income attributable to non-controlling interest is based on 18.25% of the consolidated net income of the Company’s majority owned subsidiary, Pinedale LP. Pinedale LP’s net income is comprised of all of the pro forma adjustments to the statements of income except that it excludes pro forma Management fees and income tax expense adjustments, as these are expenses that will not be incurred by Pinedale LP.