CANO PETROLEUM, INC
Form 10-K
October 20, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended: June 30, 2011

OR

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

For the transition period from to

Commission file number: 001-32496

Cano Petroleum, Inc.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**77-0635673** (I.R.S. Employer Identification No.)
6500 North Belt Line Road, Suite 200 **Irving, Texas** (Address of principal executive offices)	**75063** (Zip Code)

(214) 687-0030

(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
COMMON STOCK, PAR VALUE $.0001 PER SHARE	NYSE AMEX

Securities registered pursuant to Section 12(g) of the Exchange Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No x

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

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

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

The aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates, computed by reference to the closing sales price of such stock, as of December 31, 2010, was approximately $17.1 million. (For purposes of determination of the aggregate market value, only directors, executive officers and 10% or greater stockholders have been deemed affiliates.)

The number of shares outstanding of the registrant s common stock, par value $.0001 per share, as of October 19, 2011, was 45,057,992 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Document	**Part of the Form 10-K into which the document is incorporated**
Our definitive proxy statement relating to our 2012 annual meeting of stockholders, to be filed not later than 120 days after the end of the fiscal year covered by this report	Part III

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PART I

Items 1 and 2. Business and Properties.

Introduction

Cano Petroleum, Inc. (together with its direct and indirect subsidiaries, Cano, we, us, or the Company) is an independent oil and natural gas company. In the past, our strategy had been to convert our proved undeveloped reserves into proved producing reserves, improve operational efficiencies in our existing properties and acquire accretive proved producing assets suitable for secondary and enhanced oil recovery at low cost. Due to the Company s current financial constraints, including continued losses, defaults under our loan agreements and our Series D Preferred Stock, no available borrowing capacity, constrained cash flow, negative working capital, and limited to no other capital availability, we are reviewing strategic alternatives which include the sale of the Company, the sale of some or all of our existing oil and gas properties and assets, potential business combinations, debt restructuring including recapitalizing the Company, and bankruptcy. We continue to focus on cash management and cost reduction efforts to improve both our cash flow from operations and profitability. Our assets are located onshore in the U.S. in Texas, New Mexico, and Oklahoma.

We were organized as a corporation under the laws of the State of Delaware in May 2003 as Huron Ventures, Inc. On May 28, 2004, we merged with Davenport Field Unit, Inc., an Oklahoma corporation, and certain other entities (the Davenport Merger). In connection with the Davenport Merger, we changed our name to Cano Petroleum, Inc. Prior to the Davenport Merger, we were inactive with no significant operations.

As discussed under *Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity / Going Concern,* on July 20, 2010, we terminated our announced merger with Resaca Exploitation, Inc. (Resaca) that had been initiated pursuant to an Agreement and Plan of Merger dated September 29, 2009. On July 26, 2010, we announced the engagement of Canaccord Genuity Inc. and Global Hunter Securities to assist our management and board of directors in a review of strategic alternatives. That review is ongoing. However, even if we are able to execute successfully one of our strategic alternatives, we may not be able to meet our obligations as they become due and to continue as a going concern.

See the Glossary of Selected Oil and Natural Gas Terms at the end of Items 1 and 2 for the definition of certain terms in this annual report.

Our Properties

Cato Properties. The Cato properties include approximately 20,662 net acres across three fields in Chavez and Roosevelt Counties, New Mexico. The prime asset is the Cato Field, which covers approximately 15,000 acres. The field produces from the historically prolific San Andres formation. Although the San Andres has been successfully developed with secondary and tertiary recovery projects in the Permian Basin for decades, initiatives for enhanced recovery of the Cato Field were limited to a small area prior to Cano s acquisition. The company has designed a six-phase waterflood development plan for the field, with Phase 1 currently in operation. Estimated PDP reserves as of June 30, 2011, attributable to the Cato Properties were 314 MBbls of crude oil and 627 MMcf of natural gas (equivalent approximately to 419 MBOE).

Net production for the three months ended June 30, 2011, was 158 Bopd and 278 Mcfd (equivalent to approximately 205 BOEPD). Cano s working and net revenue interests in the Cato properties are 97% and 82%, respectively.

Panhandle Properties. The Panhandle properties include approximately 20,387 net acres in Carson, Gray and Hutchinson Counties, Texas. The majority of these properties were not waterflooded prior to Cano s acquisition. The company initiated a waterflood at the Cockrell Ranch and Harvey Ranch units in July 2007, but suspended the flood in Fiscal Year 2011 in an effort to gain improved operational efficiencies and because of capital constraints. Cano has also received approval to flood the Pond and Olive-Cooper leases, but these development plans are currently suspended. Estimated PDP reserves as of June 30, 2011, attributable to the Panhandle Properties were 1,050 MBbls of crude oil and 2,804 MMcf of natural gas (equivalent to approximately 1,517 MBOE). Net production for the three months ended June 30, 2011, was 283 Bopd and 754 Mcfd (equivalent to approximately 409 BOEPD). Cano s working and net revenue interests in the Panhandle properties are 100% and 81%, respectively.

Desdemona Properties. The Desdemona properties include approximately 10,677 net acres in mature oil fields in central Texas. Production from these properties has been primarily from the Barnett Shale and Duke Sand formations.

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Estimated PDP reserves as of June 30, 2011, attributable to the Desdemona properties were 0.4 MBbls of crude oil and 9.6 MMcf of natural gas (equivalent to approximately 2 MBOE). Net production for the three months ended June 30, 2011, was 20 Bopd and 352 Mcfd (equivalent to approximately 78 BOEPD). Cano s working and net revenue interests in the Desdemona properties are 100% and 83%, respectively.

Nowata Properties. The Nowata properties include approximately 4,594 net acres and 220 wells producing from the Bartlesville Sandstone in Nowata County, Oklahoma. These properties have been waterflooded by previous owners, and are currently being flooded by Cano. Estimated PDP reserves as of June 30, 2011, attributable to the Nowata Properties were 1,586 MBbls of crude oil and 557 MMcf of natural gas (equivalent to approximately 1,678 MBOE). Net production for the three months ended June 30, 2011, was 191 Bopd and129 Mcfd (equivalent to approximately 212 BOEPD). Cano s working and net revenue interests in the Nowata properties are 100% and 85%, respectively.

Davenport Properties. The Davenport properties include approximately 2,178 net acres and 28 wells in Lincoln County, Oklahoma. These properties were previously waterflooded, and are currently being flooded by Cano. Estimated PDP reserves as of June 30, 2011, attributable to the Cato Properties were 642 MBbls of crude oil and 125 MMcf of natural gas (equivalent to approximately 663 BOEPD). Net production for the three months ended June 30, 2011, was 69 Bopd and 16 Mcfd (equivalent to approximately 72 BOEPD). Cano s working and net revenue interests in the Davenport properties are 100% and 78%, respectively.

We have no reportable estimated proved undeveloped reserves or estimated proved developed nonproducing reserves with respect to any of our properties because we have no reasonable expectation of financing their development. Cano previously reported estimated PUD and estimated PDNP reserves in SEC filings, and would likely report estimated PUD and estimated PDNP reserves in future filings if financing for development of these reserves were to be obtained. Successful conversion of estimated PUD to estimated PDP reserves is a function of many factors and involves significant capital investment, lead times and risk. See Item1A---*Risk Factors.*

Our Strategy

Due to the our current financial constraints, which include continued losses, defaults under our loan agreements and our Series D Preferred Stock, no available borrowing capacity, constrained cash flow, negative working capital, and limited to no other capital availability, we are no longer able to pursue our historical and capital intensive strategies. These have included exploitation and development of existing properties, drilling of known formations, and acquisition of strategic assets. We are currently in the process of reviewing our strategic alternatives. We believe that these alternatives include the following:

- Sale of the Company,
- Sale of some or all of our existing oil and gas properties and assets,
- Business combinations,
- Debt restructuring, including recapitalizing the Company, with or without bankruptcy, and
- Bankruptcy.

We have engaged Canaccord Genuity Inc. as our advisor to assist in that review. After a thorough review, we believe that we are nearing the conclusion of a process that has solicited interest and offers from third parties for either the sale or combination of the entire company and/or the sale of some or all of its assets. If we are able to implement one of these options, we expect that the proceeds will be used primarily to satisfy the obligations of the company.

Proved Reserves

The following table summarizes proved reserves as of June 30, 2011, and was prepared according to the rules and regulations of the Securities and Exchange Commission (SEC).

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Summary of Estimated Oil and Gas Reserves as of Fiscal-Year End

Based on Average Fiscal-Year Prices

	Reserves (1)		
Reserves Category	**Crude Oil (MBbls)**	**Natural Gas (MMcf)**	**Total (MBOE)**
PROVED			
Developed			
Cato Properties	**314**	**627**	**419**
Panhandle Properties	**1,050**	**2,804**	**1,517**
Desdemona Properties		**10**	**2**
Nowata Properties	**1,586**	**558**	**1,678**
Davenport Properties	**642**	**125**	**663**
Subtotal	**3,592**	**4,124**	**4,279**
Undeveloped			
Cato Properties			
Panhandle Properties			
Desdemona Properties			
Nowata Properties			
Davenport Properties			
Subtotal			
TOTAL PROVED	**3,592**	**4,124**	**4,279**

(1) Separate estimated reserves are not reported for NGLs; instead, estimated natural gas reserves are reported on a wet basis that includes the NGLs that are subsequently removed from the gas stream

Our estimates of proved oil and natural gas reserves as of June 30, 2011, have been prepared by Haas Petroleum Engineering Services, Inc. (Haas), our independent reserves engineers. A copy of their reserve report of the year ended June 30, 2011, is included as Exhibit 99.1 to this Annual Report on Form 10-K. Haas has prepared our reserve estimates since the mid-year update, December 31, 2009. See Note 17 Supplementary Financial Information for Oil and Gas Producing Activities to our consolidated financial statements for additional information. Our reserve estimates as of June 30, 2011, are made in accordance with the SEC s final rule, *Modernization of Oil and Gas Reporting,* issued in December 2008 and effective for annual reports on Form 10-K for years ending on or after December 31, 2009, which amended Rule 4-10 of Regulation S-X (the Final Rule).

The prices used to compute our estimated proved oil and natural gas reserves are the average crude oil and natural gas prices during the twelve month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. For the period ending June 30, 2011, we have computed the unweighted average first-day-of-the-month NYMEX crude oil and natural gas prices to be $90.09 per barrel and $4.21 per MMBTU, respectively. Adjusting for BTU content (including NGL content), basis differentials, marketing costs and fees, crude oil quality, and transportation costs, the average net prices realized by the Company are $84.14 per barrel and $8.48 per MCF, respectively

Reserves engineering is a subjective process of estimating underground accumulations of crude oil, condensate, natural gas, and natural gas liquids that cannot be measured in an exact manner. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The reserves actually recovered, the timing of production of those reserves, as well as operating costs and the amount and timing of development expenditures may be substantially different from original estimates. Revisions result primarily from new information obtained from development drilling, production history, field tests, data analysis, and from changes in economic factors, including expectation and assumptions as to availability of financing for development projects.

We have not reported our reserves to any federal authority or agency other than the SEC pursuant to our filings with the SEC.

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Internal Controls for Reserves Estimation

Haas Petroleum Engineering Services, Inc. (Haas), our independent reserves engineers, has prepared our estimates of proved oil and natural gas reserves as of June 30, 2011. The technical personnel responsible for preparing the reserve estimates at Haas meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the SPE Standards. Haas is an independent firm of petroleum engineers, geologists, geophysicists and petrophysicists; they do not own an interest in our properties and are not employed on a contingent fee basis. Haas also prepared our estimates of proved oil and natural gas reserves for the year ended June 30, 2010. For the years ended June 30, 2009, and 2008, Miller and Lents, LTD. prepared estimates of our proved oil and natural gas reserves.

The process for preparation of our oil and gas reserves estimates is completed in accordance with our prescribed internal control procedures, which include verification of data, management review and review of the independent third party reserves report. Our reserve estimates are prepared in compliance with SEC rules, regulations and guidance and prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Properties Information (Revision as of February 19, 2007) promulgated by the Society of Petroleum Engineers (SPE Standards). A registered independent engineering firm prepares our reserve reports at the end of every year based on information provided by our Engineering and Operations Department. Eric J. Hyman, the consulting engineer responsible for overseeing the process for preparation of the reserves estimates has a Bachelor of Science degree in Petroleum Engineering, is a registered Professional Engineer in the state of Texas, has twenty-seven years of experience in reservoir engineering, and is a member of the Society of Petroleum Engineers, the Society of Petroleum Evaluation Engineers and the American Association of Petroleum Geologists. Our senior management, including our Chief Executive Officer and Chief Financial Officer, reviews our reserves estimates before these estimates are finalized and disclosed in a public filing or presentation.

Our Engineering and Operations Department accumulates historical production data for our wells, calculates historical lease operating expenses and commodity price differentials, updates working interests and net revenue interests, obtains updated authorizations for expenditure and obtains logs, 3-D seismic and other geological and geophysical information. This data is forwarded to our registered independent engineering firm as requested.

Proved Developed Producing Reserves

The following table summarizes the changes in our estimated proved developed producing reserves from June 30, 2010, to June 30, 2011.

Summary of Changes in estimated Proved Developed Producing Reserves	**MBOE**
Estimated Reserves at June 30, 2010	6,041
Reserves Revisions	(1,403)
Production for the year ended June 30, 2011	(359)
Estimated Reserves at June 30, 2011	**4,279**

Most of the revisions to our estimated proved developed producing reserves are a result of disruptions in production due to events outside the control of the company. The October 2010 fire in the Cato Field was caused by lightning, and this event not only caused an immediate impact on production, but it has also resulted in a prolonged reduction in production. The Cato waterflood was suspended for 30 days and field production declined as a result. Once injection was returned to previous levels, production has not returned to pre-fire levels. To compound the problem, a variety of mechanical and electrical issues have hampered the company s ability to improve production. Due to the production decline, Haas reduced the estimated PDP reserves projection by placing it immediately on decline. Previously, based on Cano s analytical waterflood models, the production had been held flat for several years, and then placed on decline. Haas reduced our estimated PDP reserves of the Cato properties by 431 MBOE.

During the first quarter of Fiscal Year 2011, we reduced the rate of water injection at the Cockrell Ranch and Harvey Ranch units to gain improved operational efficiencies and because of capital constraints. Consequently, the production for these Panhandle properties declined at a quicker pace than previously estimated. Due to the decline in production, Haas reduced our estimated PDP reserves of the Panhandle properties by 718 MBOE.

Reserve revisions for the Desdemona properties are relatively insignificant to us as a whole. However, operating costs increased and gas production fell below the estimates used to prepare our 2010 reserves report. Haas reduced our estimated PDP reserves of the Desdemona properties by 167 MBOE.

Haas made no significant changes to the estimated PDP reserves for the Davenport and Nowata properties.

Capital constraints during this reporting period have inhibited the Company s ability to enhance and fully maintain production.

Our operational and development activities are more fully described below under *Development Capital Expenditures and Operating Activities Update.*

Proved Undeveloped Reserves and Proved Developed Non-Producing Reserves

As of June 30, 2011, the Company has no reportable estimated proved undeveloped reserves or estimated proved developed non-producing reserves. This is a decrease of 27.0 MMBO and 43.3 MMCF (equivalent to approximately 34.2 MMBOE) from the estimated proved undeveloped reserves and a decrease of 1.3 MMBO and 5.7 MMCF (equivalent to approximately 2.3 MMBOE) from the estimated proved developed non-producing reserves reported by the Company as of June 30, 2010.

These decreases are the result of the application of the requirements of the previously cited Final Rule. Among other things, guidance for the Final Rule for the reporting of estimated proved undeveloped reserves requires that a company must have adopted a development plan and have made a final investment decision for their development. The mere intent to develop is not sufficient for reporting estimated proved undeveloped reserves. For all estimated reserves, the Final Rule requires that there must exist, or there must be a reasonable expectation that there will exist, the financing required to implement the development projects. The capital requirement for development of the estimated proved undeveloped and

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estimated proved developed non-producing reserves previously reported by the Company as of June 30, 2010, was estimated to be approximately $303.5 million and approximately$7.0 million respectively. Due to the Company s current financial constraints, including continued losses, defaults under our loan agreements and our Series D Preferred Stock, no available borrowing capacity, constrained cash flow, negative working capital, and limited to no other capital availability, there is not a reasonable expectation that the Company can obtain the financing required to implement these projects within a reasonable time, even though we believe these projects, in and of themselves, remain technically feasible and economically attractive. Therefore, we have recorded the aforementioned reduction to our estimated reserves.

Production/Operating Revenues

The following table presents sales, unit prices and average unit costs for the years ended June 30, 2011, 2010, and 2009.

	Years Ended June 30,					
		2011		**2010**		**2009**
Operating Revenues (1): (000 s)	**$**	**26,127**	**$**	**22,849**	**$**	**23,433**
Sales:						
Oil (MBbls)		266		285		308
Gas (MMcf)		447		426		545
MBOE		340		356		399
Average Price (1):						
Oil ($/Bbl)	$	84.14	$	68.98	$	62.13
Gas ($/Mcf)	$	8.48	$	7.53	$	7.28
$/BOE	$	76.85	$	64.24	$	57.93
Expense (per BOE):						
Lease operating	$	37.40	$	44.19	$	46.44
Production and ad valorem taxes	$	6.08	$	5.22	$	5.29
General and administrative expense, net	$	20.11	$	33.22	$	48.00
Depreciation and depletion	$	58.34	$	13.19	$	14.20
Total	$	121.93	$	96.62	$	113.92

(1) Excludes the effect of commodity price risk management activities

Productive Wells

The following table shows our gross and net interests in productive oil and natural gas working interest wells as of June 30, 2011. Productive wells include wells currently producing or capable of production.

	Gross(1)			Net(2)	
Oil	**Gas**	**Total**	**Oil**	**Gas**	**Total**
1,860	40	1,900	1,851	40	1,891

(1) Gross refers to wells in which we have a working interest.

(2) Net refers to the aggregate of our percentage working interest in gross wells before royalties or other payout, as appropriate

Acreage

The following table shows our gross and net acreage position in each of our properties as of June 30, 2011. We have no undeveloped acreage.

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Property	Gross Acreage (developed)	Net Acreage (developed)
Cato Properties	21,122	20,662
Panhandle Properties	20,387	20,387
Desdemona Properties	10,677	10,677
Nowata Properties	4,594	4,594
Davenport Properties	2,178	2,178
Total	58,958	58,498

Drilling Activity

The following table shows our drilling activities on a gross basis for the years ended June 30, 2011, 2010, and 2009. We own 100% working interests in all wells drilled.

	Years Ended June 30,		
	2011	2010	2009
Net Exploratory Wells			
Productive			4
Dry			
Net Development Wells			
Productive		1	14
Dry			
Total			
Productive		1	18
Dry			

Present Activities

Our present activities primarily involve continued production operations at our Panhandle, Cato, Desdemona, Nowata, and Davenport Properties. Due to the Company s current financial constraints, including continued losses, defaults under our loan agreements and our Series D Preferred Stock, no available borrowing capacity, constrained cash flow, negative working capital, and limited to no other capital availability, capital expenditures for development activities at these properties during the year ended June 30, 2011, have been limited to $1.2 million (excluding capitalized general and administrative and interest expenses), for work to maintain production primarily at our Cato, Panhandle, and Desdemona Properties. These activities are discussed in greater detail at *Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Overview Drilling Capital Development and Operating Activities Update*.

Delivery Commitments

At June 30, 2011, we had no delivery commitments with our purchasers and currently have no delivery commitments.

Title/Mortgages

Our oil and natural gas properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions as well as mortgage liens in accordance with our credit agreements. We do not believe that any of these burdens materially interferes with the use of our properties in the operation of our business.

We believe that we have generally satisfactory title to or rights in all of our producing properties. When we make acquisitions, we make title investigations, but may not receive title opinions of local counsel until we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with our use of them in the operation of our business.

Acquisitions

In the year ended June 30, 2011, the Company made no material acquisitions of oil and natural gas properties and related assets or entities owning oil and natural gas properties and related assets. Due to our ongoing financial constraints, it is unlikely that we will make any acquisitions of oil and gas properties and related assets or entities owning such assets in the foreseeable future.

Competition

We face competition from other oil and natural gas companies in all aspects of our business, including in the acquisition of producing properties and oil and natural gas leases, and in obtaining goods, services and labor. Many of our competitors have substantially greater financial and other resources than we do. Factors that affect our ability to acquire producing properties include available funds, available information about the property and our standards established for minimum projected return on investment.

Customers

We sell our crude oil and natural gas production to multiple independent purchasers pursuant to contracts generally terminable by either party upon thirty days prior written notice to the other party. During the year ended June 30, 2011, 10% or more of our total revenues were attributable to three customers accounting for: 34% (Valero Marketing Supply Co.), 24% (Coffeyville Resources Refinery and Marketing, LLC) and 11% (Sunoco, Inc.) of total operating revenue, respectively.

Title to the produced commodities transfers to the purchaser at the time the purchaser collects or receives such commodities. Prices for such production are defined in sales contracts and are readily determinable based on certain publicly available indices. The purchasers of such production have historically made payment for crude oil and natural gas purchases within thirty-five days of the end of each production month. We periodically review the difference between the dates of production and the dates we collect payment for such production to ensure that receivables from those purchasers are collectible. The point of sale for our oil and natural gas production is the title transfer point in our field gathering systems.

In the event that one or more of these significant purchasers ceases doing business with us, we believe that there are potential alternative purchasers with whom we could establish new relationships and that those relationships would result in the replacement of one or more lost purchasers. We would not expect the loss of any single purchaser to have a material adverse effect on our operations. However, the loss of a single purchaser could potentially reduce the competition for our crude oil and natural gas production, which could negatively affect the prices we receive.

Governmental Regulation

Our operations are subject to extensive and continually changing regulation affecting the oil and natural gas industry. Many departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding on the oil and natural gas industry and its individual participants. The failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability. While we do not believe that we are affected in a significantly different manner by these regulations than are our competitors, a disruption in our cash flow as a result of a governmental department or agency enforcing its regulations will likely have a disproportionate impact on us because of our current financial condition and lack of capital.

The production of crude oil and natural gas is subject to regulation under a wide range of state and federal statutes, rules, orders and regulations. State and federal statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. Texas, Oklahoma and New Mexico   the states in which we own and operate properties   have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells, the spacing of wells, and the plugging and abandonment of wells and removal of related production equipment. Texas, Oklahoma and New Mexico also restrict production to the market demand for crude oil and natural gas. These regulations can limit the amount of oil and natural gas we can produce from our wells, limit the number of wells, and limit the locations at which we can conduct drilling

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operations. Moreover, each state generally imposes a production or severance tax with respect to production and sales of crude oil, natural gas and gas liquids within its jurisdiction.

Transportation and Sale of Natural Gas

Our natural gas sales were approximately 15% of our total sales revenue during the year ended June 30, 2011. The interstate transportation and sale for resale of natural gas is subject to federal regulation, including transportation rates and various other matters, by the Federal Energy Regulatory Commission (FERC). Federal wellhead price controls on all domestic natural gas were terminated on January 1, 1993, and none of our natural gas sales prices are currently subject to FERC regulation. We cannot predict the impact of future government regulation on our natural gas operations.

Insurance

Our insurance policies currently provide for $1,000,000 general liability coverage for bodily injury and property damage including pollution, underground resources, blowout and cratering. We have an Owned-Hired and Non-Owned commercial automobile liability limit of $1,000,000. Additionally, we have a $2,000,000 policy for control of well, re-drill, and pollution on drilling wells and producing wells. At June 30, 2011, we had $50,000,000 umbrella coverage in excess of the general liability and automobile liability. At the renewal of our policies in August 2011, we reduced the umbrella coverage to $35,000,000, leaving all other coverage unchanged.

Environmental Regulations

Our operations are subject to numerous stringent and complex laws and regulations at the federal, state and local levels governing the discharge of materials into the environment or otherwise relating to human health and environmental protection. These laws and regulations may, among other things, require acquisition of a permit before drilling or development commences, restrict the types, quantities and concentrations of various materials that can be released into the environment in connection with development and production activities, and limit or prohibit construction or drilling activities in certain ecologically sensitive and other protected areas. Failure to comply with these laws and regulations or to obtain or comply with permits may result in the assessment of administrative, civil and criminal penalties, imposition of remedial requirements and the imposition of injunctions to force future compliance. Our business and prospects could be adversely affected to the extent laws are enacted or other governmental action is taken that prohibits or restricts our development and production activities or imposes environmental protection requirements that result in increased costs to us or the oil and natural gas industry in general.

We conduct our development and production activities to comply with all applicable environmental regulations, permits and lease conditions, and we monitor subcontractors for environmental compliance. While we believe our operations conform to those conditions, we remain at risk for inadvertent noncompliance, conditions beyond our control and undetected conditions resulting from activities of prior owners or operators of properties in which we own interests.

Occupational Safety Regulation

We are subject to various federal and state laws and regulations intended to promote occupational health and safety. Although all of our wells are drilled by independent subcontractors under our footage or day rate drilling contracts, we have adopted environmental and safety policies and procedures designed to protect the safety of our own supervisory staff and to monitor all subcontracted operations for compliance with applicable regulatory requirements and lease conditions, including environmental and safety compliance. This program includes regular field inspections of our drill sites and producing wells by members of our operations staff and internal assessments of our compliance procedures. We consider the cost of compliance a manageable and necessary part of our business.

Federal, State or Native American Leases

Our operations on federal, state or Native American oil and natural gas leases are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the U.S. Department of Interior, Bureau of Land Management, the Office of Natural Resources Revenue, and other agencies.

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Employees

We and our wholly-owned subsidiaries have 29 employees as of June 30, 2011. All of our employees are full-time employees. None of our employees are represented by a labor union. We have never experienced an interruption in operations from any kind of labor dispute, and we consider the working relationships among the members of our staff to be generally good.

During the year ended June 30, 2011, we reduced employees at our home office by approximately 89%. Many home office functions are now performed by independent contractors.

Principal Executive Offices

Our principal executive offices are located at 6500 North Belt Line Road, Suite 200, Irving, TX 75063. Our principal executive offices consist of 9,163 square feet and are subject to a lease that expires on March 31, 2016.

Internet Address/Availability of Reports

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, are made available free of charge on our website at *http://www.canopetro.com* as soon as reasonably practicable after we electronically file such material with, or otherwise furnish it to, the SEC. The information presented on our website is not considered to be part of this filing or any other filing that we make with the SEC.

Glossary of Selected Oil and Natural Gas Terms

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

BOE. Barrels of oil equivalent. BTU equivalent of six thousand cubic feet (Mcf) of natural gas, which is equal to the BTU equivalent of one barrel of oil.

BOEPD BOE per day.

Bopd Barrels of oil per day.

BTU. British Thermal Unit.

DRY HOLE. A development or exploratory well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

ENHANCED OIL RECOVERY or EOR. The use of certain methods, such as waterflooding or gas injection, into existing wells to increase the recovery from a reservoir.

EXPLORATORY WELL A well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir. We incur costs associated with secondary and tertiary techniques that involve drilling and equipping exploratory wells. This occurs within reservoirs for which we already have proved developed reserves recorded from existing primary or secondary development; however, there are no proved reserves for subsequent secondary or tertiary activities.

FLUID INJECTION. Pumping fluid into a producing formation to increase or maintain reservoir pressure and, thus, production.

GROSS ACRES or GROSS WELLS. The total number of acres or wells, as the case may be, in which a working or any type of royalty interest is owned.

MBbls. One thousand Bbls.

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MBOE. One thousand BOE.

Mcf. One thousand cubic feet of natural gas.

Mcfd One thousand cubic feet of natural gas per day.

MMBOE. One million BOE.

MMcf. One million cubic feet of natural gas.

NET ACRES or NET WELLS. The sum of the fractional working or any type of royalty interests owned in gross acres or wells, as the case may be.

NGL. Natural Gas Liquids. Components of natural gas that are liquid at the surface in field facilities or in gas-processing plants. Natural gas liquids can be classified according to their vapor pressures as low (condensate), intermediate (natural gasoline) and high (liquefied petroleum gas) vapor pressure. Natural gas liquids include propane, butane, pentane, hexane and heptane, but not methane and ethane, since these hydrocarbons need refrigeration to be liquefied.

PRIMARY RECOVERY. The period of production in which oil moves from its reservoir through the wellbore under naturally occurring reservoir pressure.

PRODUCING WELL or PRODUCTIVE WELL. A well that is capable of producing oil or natural gas in economic quantities.

PDP or PROVED DEVELOPED PRODUCING RESERVES. The oil and natural gas reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

PDNP or PROVED DEVELOPED NON-PRODUCING RESERVES. The oil and natural gas reserves that can be estimated to be recovered through existing wells with existing equipment and operating methods, but are not currently producing.

PORE VOLUME INJECTION or PVI means the injection of water or surfactants, polymers and other additives into the void space of a producing formation. The amount of a pore volume injection or PVI is the amount of void space of a producing formation that has been displaced with water or surfactants, polymers and other additives.

PROVED RESERVES. Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible - from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations - prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas based on available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the

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potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PUD or PROVED UNDEVELOPED RESERVES. The oil and natural gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery techniques is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

ROYALTY INTEREST. An interest in an oil and natural gas property entitling the owner to a share of oil and natural gas production free of production costs.

SECONDARY RECOVERY. The recovery of oil and natural gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Secondary recovery methods are often applied when production slows due to depletion of the natural pressure.

STANDARDIZED MEASURE. Under the Standardized Measure, future cash flows are estimated by applying year-end prices, adjusted for fixed and determinable changes, to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pretax cash inflows. Future income taxes are computed by applying the statutory tax rate to the excess inflows over a company s tax basis in the associated properties. Tax credits, net operating loss carry-forwards and permanent differences also are considered in the future tax calculation. Future net cash inflows after income taxes are discounted using a 10% annual discount rate to arrive at the Standardized Measure.

SURFACTANT-POLYMER FLOODING AND ALKALINE-SURFACTANT-POLYMER (ASP) FLOODING. Enhanced oil recovery techniques that can be employed to recover additional oil over and above primary and secondary recovery methods. Low concentrations of surfactants, polymers and other additives that are added to the waterflood operations already in place to clean stubborn or hard to reach oil from the reservoir.

TERTIARY RECOVERY. The use of improved recovery methods that not only restores formation pressure but also improves oil displacement or fluid flow in the reservoir and removes additional oil after secondary recovery.

U.S. The United States of America.

WATERFLOODING. A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and sweep oil into the producing wells.

WORKING INTEREST. The operating interest (not necessarily as operator) that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production, subject to all royalties, overriding

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royalties and other burdens, and to all exploration, development and operational costs including all risks in connection therewith.

Item 1A. Risk Factors.

Our business involves a high degree of risk. Investors should carefully consider the risks and uncertainties described below. Each of the following risks may materially and adversely affect our business, results of operations and financial condition. These risks may cause the market price of our common stock to decline, which may cause you to lose all or a part of the money you paid to buy our common stock.

Risks Related to Our Business

Our auditors have issued a   going concern   audit opinion.

Our consolidated financial statements as of June 30, 2011, have been prepared on the assumption that we will continue as a going concern. Our independent accountants have issued a report dated October 20, 2011, stating that our significant losses from operations and net capital deficiency raise substantial doubt as to our ability to continue as a going concern. There can be no assurance that we will be able to continue as a going concern.

If we file for bankruptcy protection, holders of our common stock and preferred stock may be severely diluted or eliminated entirely in connection with a bankruptcy filing or restructuring transaction.

If we are unable to successfully execute one of our strategic alternatives, restructure our existing indebtedness, obtain further waivers or forbearance from our existing lenders or otherwise raise significant additional capital, it is unlikely that we will be able to meet our obligations as they become due and to continue as a going concern. As a result, we will likely file for bankruptcy or seek similar protection. Moreover, it is possible that our creditors may seek to initiate involuntary bankruptcy proceedings against us or against one or more of our subsidiaries, which would force us to make defensive voluntary filing(s) of our own. In addition, if we restructure our debt or file for bankruptcy protection, it is very likely that our common stock and preferred stock will be severely diluted if not eliminated entirely.

We have no borrowing capacity under our credit agreements, and unless we are able to successfully execute one of our strategic alternatives, restructure our existing indebtedness, obtain further waivers or forbearance from our existing lenders or otherwise raise significant capital, it is unlikely that we will be able to meet our obligations as they become due and to continue as a going concern.

We have sustained recurring losses and negative cash flows from operations. Over the periods presented in the accompanying financial statements, our growth has been funded through a combination of equity financings, borrowings under our credit agreements, the sale of assets and cash flows from operating activities. As of June 30, 2011, we had approximately $1.7 million of cash and cash equivalents available to fund operations and essentially no additional funds available for operations.

On July 20, 2010, we terminated our announced merger with Resaca that had been initiated pursuant to an Agreement and Plan of Merger dated September 29, 2009. On July 26, 2010, we announced the engagement of Canaccord Genuity and Global Hunter Securities to assist our Board in a review of strategic alternatives, with a goal of maximizing economic value for our shareholders. The strategic alternatives we are considering include the sale of the Company, the sale of some or all of our existing oil and gas properties and assets, potential business combinations, and debt restructuring, including possible bankruptcy and recapitalizing the Company.

We currently have limited access to capital. On August 5, 2010, we finalized Consent and Forbearance Agreements with the lenders under our credit agreements that waived covenant compliance issues for the period ended June 30, 2010,and potential covenant compliance issues for the period ending September 30, 2010, set certain deadlines for the execution of our strategic alternatives process and allowed us to sell certain natural gas commodity derivative contracts for cash proceeds of $0.8 million, which was intended to provide Cano sufficient liquidity to complete our strategic alternatives process. The Consent and Forbearance Agreements were terminated as our lenders delivered Reservation of Rights Letters dated September 24, 2010, January 5, 2011, and September 23, 2011. On August 31, 2011, we failed to make a required payment of interest under our senior credit agreement. Our failure to make such payment of interest constituted an Event of Default under our senior and subordinated credit agreements, for which the lenders under such credit agreements may terminate their obligation to extend credit to us and declare all amounts payable under our senior and subordinated credit agreements due and payable in full. We have not received any

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notice from the lenders with respect to the exercise of their respective rights, including any right to accelerate the amounts payable by us. We continue to work with our lenders and advisors as we consider strategic alternatives. We currently have no available borrowing capacity under our senior and subordinated credit agreements.

The accompanying Consolidated Financial Statements have been prepared on a going concern basis which contemplates continuity of operations, realization of assets and liquidation of liabilities in the ordinary course of business. As a result of losses incurred and our current negative working capital, there is no assurance that the carrying amounts of assets will be realized or that liabilities will be settled for the amounts recorded. The ability of the Company to continue as a going concern will be dependent upon the outcome of the strategic alternatives review. Unless we are able to successfully execute one of our strategic alternatives, restructure our existing indebtedness, obtain further waivers or forbearance from our existing lenders or otherwise raise significant additional capital, it is unlikely that we will be able to meet our obligations as they become due and to continue as a going concern. We can provide no assurance that we will be successful in our efforts to execute one of our strategic alternatives, restructure our existing indebtedness, obtain further waivers or forbearance from our existing lenders or otherwise raise significant additional capital.

We are unable to redeem, and do not expect in the foreseeable future to be able to redeem, our Series D Convertible Preferred Stock.

Pursuant to the terms of our Series D Convertible Preferred Stock (the Preferred Stock), we were required to redeem all outstanding shares of Preferred Stock as of September 6, 2011, its maturity date. However, the subordination provisions of our Preferred Stock prohibit us from redeeming our Preferred Stock while we are in default under our senior credit agreement. As a result of our defaults under our senior and subordinated credit agreements, we were not able to redeem our outstanding Preferred Stock as of its maturity date. Without successfully implementing one of our strategic alternatives or restructuring our existing indebtedness, we do not expect to be able to cure our defaults under our senior and subordinated credit agreements any time in the foreseeable future. Accordingly, we do not expect to be able to redeem our outstanding Preferred Stock in the foreseeable future.

In addition, we cannot issue any preferred stock that is senior or on par with the Preferred Stock with regard to dividends or liquidation without the approval of holders of a majority of the Preferred Stock.

We are subject to many restrictions imposed by our lenders under our credit agreements which may adversely impact our future operations.

We currently have limited access to capital. On August 5, 2010, we finalized Consent and Forbearance Agreements with the lenders under our credit agreements that waived potential covenant compliance issues for the periods ending June 30, 2010,and September 30, 2010, set certain deadlines for the execution of our strategic alternatives process and allowed us to sell certain natural gas commodity derivative contracts for cash proceeds of $0.8 million, which was intended to provide Cano sufficient liquidity to complete its strategic alternatives process. The Consent and Forbearance Agreements were terminated as our lenders delivered Reservation of Rights Letters dated September 24, 2010, January 5, 2011, and September 23, 2011. On August 31, 2011, we failed to make a required payment of interest under our senior credit agreement. Our failure to make such payment of interest constituted an Event of Default under our senior and subordinated credit agreements, for which the lenders under such credit agreements may terminate their obligation to extend credit to us and declare all amounts payable under our senior and subordinated credit agreements due and payable in full. We have not received any notice from the lenders with respect to the exercise of their respective rights, including any right to accelerate the amounts payable by us. We currently have no available borrowing capacity under our senior and subordinated credit agreements.

Our lenders have terminated each of the Consent and Forbearance Agreements with respect to our credit agreements, and we have no guarantee that they will not declare the amounts owed under our credit agreements immediately payable and exercise any other available rights and remedies.

On September 24, 2010, the lenders under our credit agreements notified us, through the delivery of Reservation of Rights Letters, subsequently updated on January 5, 2011, and September 23, 2011, that we had failed to timely comply with certain covenants in the Consent and Forbearance Agreements dated August 5, 2010, with such parties, and, as a result thereof, such Consent and Forbearance Agreements were terminated. We have not received any notice from the lenders with respect to the exercise of their respective rights, including any right to accelerate the amounts payable by us. On August 31, 2011, we failed to make a required payment of interest under the amended and restated credit agreement (ARCA). Our failure to make such payment of interest

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constituted an Event of Default under the ARCA and the subordinated credit agreement (SCA), for which the lenders under such credit agreements may terminate their obligation to extend credit to us and declare all amounts payable under the ARCA and the SCA due and payable in full. We have not received any notice from the lenders with respect to the exercise of their respective rights, including any right to accelerate the amounts payable by us. However, if our lenders declare the amounts owed under our credit agreements immediately due and payable, we are unsure of our ability to continue as a going concern. We have not obtained any further waiver or forbearance from the lenders with respect to our credit agreements, and there is no guarantee that we will be able to obtain any waiver or forbearance in the future.

If we cannot obtain sufficient capital when needed, we will not be able to continue with our historical business strategy.

Our business strategy has historically included developing and acquiring interests in mature oil fields with established primary and/or secondary reserves that may possess significant remaining upside exploitation potential by implementing various secondary and/or tertiary EOR techniques. If we are able to continue our historical business plan, we will require additional capital to finance acquisitions as well as to conduct our EOR operations. Due to our current liquidity constraints, it is unlikely that we will make any acquisitions of oil and gas properties and related assets or entities owning such assets for the foreseeable future. Additionally, in the future, we may not be able to obtain financing in sufficient amounts or on acceptable terms when needed, which could adversely affect our operating results and prospects. If we cannot raise the capital required to implement our historical business strategy, we may be required to curtail operations, which could adversely affect our financial condition and results of operations. Further, any debt financing must be repaid and redeemable preferred stock must be redeemed regardless of whether or not we generate profits or cash flows from our business activities.

Our operations could be adversely affected if we fail to maintain required bonds.

Federal and state laws require bonds or cash deposits to secure our obligations with respect to various parts of our operations. Our failure to maintain, or inability to acquire, bonds that are required by state and federal law would have a material adverse effect on us. That failure could result from a variety of factors including: our failure to comply with rules and regulations of Federal and state governmental agencies, including the United States Bureau of Land Management, the lack of availability of bonding, higher expense or unfavorable market terms of new bonds; and the exercise by third-party bond issuers of their right to refuse to renew the bonds. If we fail to maintain required bonds, our production may significantly decrease, which would significantly decrease our already constrained cash flow.

The actual quantities and present value of our proved reserves may be lower than we have estimated.

This annual report contains estimates of our proved reserves. The process of estimating oil and natural gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from these estimates and vary over time. Such variations may be significant and could materially affect the estimated quantities and present value of our proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of drilling, results of secondary and tertiary recovery applications, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

We have no proved undeveloped reserves and, for the foreseeable future, we will not be able to develop any of our properties.

We do not have any reportable estimated proved undeveloped or estimated proved developed nonproducing reserves with respect to any of our properties, because we have no reasonable expectation of financing the development of our properties. We have no borrowing capacity under our credit agreements. Unless we are able to successfully raise significant additional capital, we will not be able to further develop any of our properties. We can provide no assurance that we will be successful in our efforts to raise significant additional capital.

We may not achieve the production growth we anticipate from our properties or properties we acquire.

Our operational strategy has historically been to implement waterflood and EOR techniques upon our existing properties. The performance of waterflood and EOR techniques is often difficult to predict and takes an extended period of time from first investment until actual production. Additionally, we may not achieve the anticipated production growth from properties we own or acquire in the future.

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Acquisitions may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities.

Our historical growth has been due in part to acquisitions of exploration and production companies, producing properties and undeveloped leaseholds. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, recovery applicability from waterflood and EOR techniques, future oil and natural gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform reviews of acquired properties which we believe are generally consistent with industry practices. However, such reviews will not reveal all existing or potential problems. In addition, these reviews may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Additionally, we do not inspect every well or property. Even when we inspect a well or property, we do not always discover structural, subsurface and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an as is basis with limited remedies for breaches of representations and warranties. As a result of these factors, we may not be able to acquire oil and natural gas properties that contain economically recoverable reserves or recover oil from the properties we have acquired.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. It has been our historical intention to focus on acquiring properties located in onshore United States. To the extent that we acquire properties substantially different from the properties in our primary operating regions or acquire properties that require different technical expertise, we may not be able to realize the economic benefits of these acquisitions

Exploration and development drilling and the application of waterflooding and EOR techniques may not result in commercially productive reserves.

The new wells we drill or participate in, whether undertaken in primary drilling or utilizing waterflood or EOR techniques may not be productive and we may not recover all or any portion of our investment. The engineering data and other technologies we use do not allow us to know conclusively, prior to beginning a project, that crude oil or natural gas is present in the reservoir or that those reserves can be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Our efforts will be unprofitable if we drill dry holes or wells that are productive but do not produce enough reserves to generate an economic return. Further, our drilling and other operations may be curtailed, delayed or canceled as a result of a variety of factors, including but not limited to:

- unexpected drilling conditions;
- title and permitting problems;
- pressure or irregularities in formations;

- equipment failures or accidents;
- volatility in crude oil and natural gas prices;
- adverse weather conditions; and
- increases in the costs of, or shortages or delays in the availability of, chemicals, drilling rigs and equipment.

Certain of our current development and exploration (waterflood or EOR techniques where no proved waterflood or EOR reserves have previously been recorded) activities may not be successful and, if unsuccessful, this failure could have an adverse effect on our future results of operations and financial condition. While all crude oil and natural gas activities, whether developmental or exploratory, involve these risks, exploratory activities involve greater risks of failure to find and produce commercial quantities of crude oil or natural gas.

Our board of directors and management team have recently changed, and our failure to successfully adapt to these changes, a failure by our new management team to successfully manage our operations, or our inability to fill vacant key management positions may adversely affect our business.

We have experienced several recent departures at our board of directors and executive levels, including the departure of five directors, our Chief Executive Officer, our Chief Financial Officer and our General Counsel. Our future success is dependent on the personal efforts, performance and abilities of key management, including James R. Latimer, III,

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our new Chief Executive Officer and member of our board of directors, and John H. Homier, our new Chief Financial Officer. Each of these individuals are integral parts of our daily operations. We do not maintain any key life insurance policies for any of our executive officers or other personnel. The further loss of any of our current officers could significantly impact our business until adequate replacements can be identified and put in place.

As a result of our strategic alternatives process, we are operating with a reduced work force which may affect our ability to run our business. Additionally, we may not be able to hire qualified replacements for lost employees in the future.

We face strong competition from larger oil and natural gas companies.

Our competitors include large integrated oil and natural gas companies and numerous independent oil and natural gas companies, individuals and drilling and income programs. Many of these competitors are well-established companies with substantially larger operating staffs and greater capital resources than we have. These larger competitors may be able to pay more for exploratory prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, such companies may be able to expend greater resources on the existing and changing technologies that we believe are, and will be, increasingly important to attaining success in the industry.

The geographic concentration of our oil and gas reserves may have a greater effect on our ability to sell oil and gas compared to larger, more geographically diverse companies and may make us more sensitive to price volatility.

All of our oil and gas reserves are located in Texas, New Mexico and Oklahoma. Since our reserves are not as diversified geographically as many of our larger, more geographically diverse competitors, our business could be more subject to local conditions than other, more diversified companies. Any regional events, including price fluctuations, natural disasters, oil and gas processing or transportation interruptions, and restrictive regulations, that increase costs, reduce availability of equipment or supplies, reduce demand or limit our production may impact our operations more than if our reserves were more geographically diversified. For example, if Cushing, OK, a major crude oil trading hub in North America, experienced a shortage in capacity, then our crude oil price might be adversely affected. In 2011, this actually occurred, and the crude oil price at Cushing lost parity with other world benchmark prices.

Our business will depend on gathering and transportation facilities owned by others. Any limitation in the availability of those facilities would interfere with our ability to market the oil and natural gas that we produce.

The marketability of our crude oil and natural gas production will depend in part on the availability, proximity and capacity of gathering and pipeline systems owned by third parties. The amount of crude oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering or transportation system, or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or pipeline capacity, or significant delay in the construction of necessary gathering and transportation facilities, could adversely affect our business, results of operations, financial condition and prospects.

Our ability to use net operating loss carryovers to offset future taxable income may be limited.

Depending on the outcome of our strategic alternatives review as discussed in Note 2 of the Consolidated Financial Statements, our federal income tax net operating loss (NOL) carry-forwards could be subject to the ownership change limitation provisions of the Internal Revenue Code. This will result in a limitation on the use of NOL carry-forwards to a specified amount per year. The Company may not able to fully utilize these existing NOL carry-forwards in future years and there can be no certainty that any of our NOL carry-forwards will be utilized by us in the future.

Derivative activities create a risk of potentially limiting the ability to realize profits when prices increase.

From time to time, we may maintain commodity derivative contracts to mitigate the impact of a decline in crude oil and natural gas prices. Such commodity derivative contracts could prevent us from realizing the full advantage of increases in crude oil or natural gas prices if the NYMEX crude oil and natural gas prices exceed the contract price ceiling. In addition, these transactions may expose us to the risk of financial loss if the counterparties to our derivative contracts fail to perform under the contracts. Also, increases in crude oil and natural gas prices would negatively affect the fair value of commodity

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derivatives contracts that we would be required to record on our balance sheet and, consequently, our reported net income. Changes in the recorded fair value of our derivatives contracts would be marked to market through earnings and the decrease in the fair value of these contracts during any period could result in significant charges to earnings. We are currently unable to estimate the effects on earnings in future periods, but the effects could be significant

We reported material weaknesses in our internal control over financial reporting. Failure to maintain effective internal controls could have a material adverse effect on our operations.

We are subject to Section 404 of the Sarbanes-Oxley Act, which requires annual management assessments of the effectiveness of our internal control over financial reporting. Effective internal controls are necessary for us to produce reliable financial reports. If, as a result of deficiencies in our internal controls, we cannot provide reliable financial reports, our business decision process may be adversely affected, our business and operating results could be harmed, we may be in violation of our lending covenants, investors could lose confidence in our reported financial information and the price of our stock could decrease as a result.

During our evaluation of disclosure controls and procedures for the year ended June 30, 2010 and based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), we concluded that our internal control over financial reporting was not effective because of the material weaknesses described below.

A material weakness is a significant deficiency, or combination of significant deficiencies, that results in there being a more than remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

Our independent registered public accounting firm advised our audit committee that the following material weaknesses in internal control existed as of June 30, 2011:

- Our review of our valuation of commodity derivatives did not detect errors in the unrealized loss on commodity derivatives that resulted in a material audit adjustment to our financial statements.

- Our review of certain other computations did not detect errors in such calculations that resulted in adjustments to our financial statements that were less than material, but important enough to merit attention by those responsible for our financial reporting oversight. The aggregate effect of this deficiency when combined with the material weakness described above constitutes a material weakness in internal control over financial reporting.

- We were unable to complete our internal control procedures over financial reporting in a sufficient amount of time to allow us to include our consolidated financial statements in this Annual Report and file it within the time periods specified in the rules and forms of the SEC.

In our judgment, the material weaknesses listed above resulted from significant turnover of our accounting and finance personnel that left us with new accounting and finance personnel who lacked familiarity with our accounting systems, methods and policies.

Until they are fully remediated, these material weaknesses could lead to errors in our reported financial results and could have a material adverse effect on our operations, investor confidence in our reported financial information and the trading price of our securities. We cannot guarantee that we will be successful in remediating any material weaknesses in our internal control over financial reporting. Further, we cannot assure you that additional significant deficiencies or material weaknesses in our internal control over financial reporting will not be identified in the future. Any failure to maintain or implement required new or improved controls, or any difficulties we encounter in their implementation, could result in additional significant deficiencies and material weaknesses, and cause us to fail to meet our periodic reporting obligations or result in material misstatements in our financial statements.

Our business involves many operating risks, which may result in substantial losses, and insurance may be unavailable or inadequate to protect us against these risks.

Our operations are subject to hazards and risks inherent in drilling for, producing and transporting oil and natural gas, such as:

- fires;
- natural disasters;
- explosions;
- pressure forcing oil or natural gas out of the wellbore at a dangerous velocity coupled with the potential for fire or explosion;
- weather;
- failure of oilfield drilling and service tools;
- changes in underground pressure in a formation that causes the surface to collapse or crater;
- pipeline ruptures or cement failures;

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- environmental hazards such as natural gas leaks, oil spills and discharges of toxic gases; and
- availability of needed equipment at acceptable prices, including steel tubular products.

Any of these risks can cause substantial losses resulting from:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

Part of our business is seasonal in nature, which may affect the price of our oil and natural gas sales, and severe weather may adversely affect our ability to deliver oil and natural gas production.

Weather conditions affect the demand for and price of oil and natural gas. Demand for oil and natural gas is typically higher during winter months than summer months. However, warm winters can also lead to downward price trends. Therefore, our results of operations may be adversely affected by seasonal conditions. Severe weather can cause interruptions to our production and temporarily shut-in production from our wells.

Unfavorable results of litigation could have a material adverse impact on our financial statements.

We are subject to a variety of claims and lawsuits that arise from time to time in the ordinary course of our business. Management currently believes that resolving any of such matters, individually or in the aggregate, will not have a material adverse impact on our financial position or results of operations. The litigation and claims are subject to inherent uncertainties and management s view of these matters may change in the future. There exists the possibility of a material adverse impact on our financial position and the results of operations for the period in which the effect of an unfavorable final outcome becomes probable and reasonably estimable. Please see *Legal Proceedings* for a discussion of our material pending legal proceedings.

Currently, our lease operating expense per BOE is high in comparison to the oil and natural gas industry as a whole.

Until we achieve significant production growth from our waterfloods, our lease operating expense per BOE should remain higher than companies drilling for primary production. These higher operating costs could have an adverse effect on our results of operations.

Risks Related to Our Industry

Crude oil and natural gas prices are volatile. A substantial or sustained decline in prices could adversely affect our financial position, financial results, cash flows and access to capital.

Our revenues and operating results depend primarily upon the prices we receive for the crude oil and natural gas we produce and sell. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Historically, the markets for crude oil and natural gas have been volatile and they are likely to continue to be volatile. The prices we receive for our crude oil and natural gas are based upon factors that are beyond our control, including:

- worldwide and domestic demands and supplies of oil and natural gas;

- weather conditions;

- the price and availability of alternative fuels;

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- the availability of pipeline capacity;
- the price and level of foreign imports;
- domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil-producing regions; and
- the overall economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future crude oil and natural gas price movements with any certainty. Declines in crude oil and natural gas prices would not only reduce revenue, but could reduce the amount of oil and natural gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves.

Government regulation may adversely affect our business and results of operations.

Oil and natural gas operations are subject to various and numerous federal, state and local government regulations, which may be changed from time to time. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, spacing of wells, injection of substances, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity in order to conserve supplies of oil and natural gas. Certain federal, state and local laws and regulations applicable to the development, production, handling, storage, transportation and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations, exist for the purpose of protecting the human health and the environment. The transportation and storage of refined products include the risk that refined products and other hydrocarbons may be suddenly or gradually released into the environment, potentially causing substantial expenditures for a response action, significant government penalties, liability to government agencies and private parties for natural resources damages, personal injury, or property damages and significant business interruption. We own or lease a number of properties that have been used to store or distribute refined and unrefined products for many years. Many of these properties have also been operated by third parties whose handling, disposal, or release of hydrocarbons and other wastes were not under our control. As a result, we may incur substantial expenditures and/or liabilities to third parties or governmental entities which could have a material adverse effect on us.

The oil and natural gas industry is capital intensive, and we will likely be unable to raise the capital needed to conduct our operations as planned or to make strategic acquisitions.

The oil and natural gas industry is capital intensive. We make substantial capital expenditures for the acquisition of, exploration for and development of, crude oil and natural gas reserves. Due to our current liquidity constraints, it is unlikely that we will make any acquisitions of oil and gas properties and related assets or entities owning such assets for the foreseeable future.

Historically, we have financed capital expenditures with cash generated by operations, proceeds from bank borrowings and sales of equity securities. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

Any one of these variables can materially affect our ability to access the capital markets.

If our revenues decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to fund future development projects. We may, from time to time, seek additional financing, either in the form of bank borrowings, public or private sales of debt or

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equity securities or other forms of financing, or consider selling non-core assets to raise additional operating capital. However, we may not be able to obtain additional financing or sell non-core assets upon terms acceptable to us.

Any prolonged, substantial reduction in the demand for oil and gas, or distribution problems in meeting this demand, could adversely affect our business.

Our success is materially dependent upon the demand for oil and gas. The availability of a ready market for our oil and gas production depends on a number of factors beyond our control, including the demand for and supply of oil and gas, the availability of alternative energy sources, the proximity of reserves to, and the capacity of, oil and gas gathering systems, pipelines or trucking and terminal facilities. We may also have to shut-in some of our wells temporarily due to a lack of market or adverse weather conditions. If the demand for oil and gas diminishes, our financial results would be negatively impacted.

In addition, there are limitations related to the methods of transportation for our production. Substantially all of our oil and gas production is transported by pipelines and trucks owned by third parties. The inability or unwillingness of these parties to provide transportation services to us for a reasonable fee could result in us having to find transportation alternatives, increased transportation costs or involuntary curtailment of a significant portion of our oil and gas production, any of which could have a negative impact on our results of operation and cash flows.

Environmental liabilities could adversely affect our financial condition.

The oil and gas business is subject to environmental hazards, such as oil spills, gas leaks and ruptures and discharges of petroleum products and hazardous substances, and historic disposal activities. These environmental hazards could expose us to material liabilities for property damages, personal injuries or other environmental harm, including costs of investigating and remediating contaminated properties. A variety of stringent federal, state and local laws and regulations govern the environmental aspects of our business and impose strict requirements for, among other things:

• well drilling or workover, operation and abandonment;

• waste management;

• land reclamation;

• financial assurance under the Oil Pollution Act of 1990; and

• controlling air, water and waste emissions.

Any noncompliance with these laws and regulations could subject us to material administrative, civil or criminal penalties or other liabilities. Additionally, our compliance with these laws may, from time to time, result in increased costs of production, development or exploration, or decreased production, and may affect our costs of acquisitions.

Our liability for environmental hazards includes those created either by the previous owners of properties that we purchase or lease or by acquired companies prior to the date we acquire them. We maintain insurance against some, but not all, of the risks described above. Our insurance policies currently provide for $1,000,000 general liability coverage for bodily injury and property damage including pollution, underground resources, blowout and cratering. We have   an   Owned-Hired and Non-Owned   Commercial Automobile liability limit of $1,000,000. There is a $2,000,000 policy for control of well, re-drill, and pollution on drilling wells and producing wells. Our insurance may not be adequate to cover casualty losses or liabilities. At June 30, 2011, we had $50,000,000 umbrella coverage in excess of the general liability and automobile liability. At the renewal of our policies in August 2011, we reduced the umbrella coverage to $35,000,000, leaving all other coverage unchanged. In the future, we may not be able to obtain insurance at premium levels that justify its purchase.

We do not insure against the loss of oil or natural gas reserves as a result of operating hazards, insure against business interruption or insure our field production equipment against loss. Losses could occur for uninsurable or uninsured risks, or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could harm our financial condition and results of operations. Additionally, pollution and similar environmental risks generally are not fully insurable.

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Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

President Obama s budget proposal for fiscal year 2012, or the Budget Proposal, contains a proposal to eliminate certain key U.S. federal income tax preferences currently available to coal, oil and gas exploration and production companies. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for U.S. production activities and (iv) the increase in the amortization period from two years to seven years for geophysical costs paid or incurred in connection with the exploration for, or development of, oil or gas within the United States. It is unclear whether any such changes will actually be enacted or, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of the Budget Proposal or any other similar change in U.S. federal income tax law could affect certain tax deductions that are currently available with respect to oil and gas exploration and production and could negatively impact the value of an investment in our common stock.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

On December 15, 2009, the U.S. Environmental Protection Agency (EPA) officially published its findings that emissions of carbon dioxide, methane and other greenhouse gases (GHG) present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth s atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its findings that would require a reduction in emissions of greenhouse gases from motor vehicles and that could also lead to the imposition of greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. In March 2010, the EPA announced a proposed rulemaking that would expand its final rule on reporting of GHG emissions to include owners and operators of onshore oil and natural gas production facilities. If the proposed rule is finalized in its current form, reporting of GHG emissions from such facilities would be required on an annual basis beginning in 2012 for emissions occurring in 2011. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the oil and natural gas that we produce.

Federal and state governments are considering enacting new legislation and promulgating new regulations governing or restricting the emission of greenhouse gases. The EPA has already made findings and issued proposed regulations that could lead to the imposition of restrictions on greenhouse gas emissions from motor vehicles and certain stationary sources and that could require us to establish and report an inventory of greenhouse gas emissions. In addition, the U.S. Congress has been considering various bills that would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. Such a program, if enacted, could require phased reductions in greenhouse gas emissions over several or many years as could the issuance of a declining number of tradable allowances to sources that emit greenhouse gases into the atmosphere. Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require us to incur additional operating costs and could adversely affect demand for the oil and natural gas that we sell. The potential increase in our operating costs could include new or increased costs to obtain permits, operate and maintain our equipment and facilities, install new emission controls on our equipment and facilities, acquire allowances to authorize our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for oil and natural gas.

Derivatives regulation included in current financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices.

From time to time, we enter into derivatives contracts in order to hedge portions of our natural gas and oil production. The United States Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as ours, that participate in that market. The legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, was signed into law by the President on July 21, 2010, and its provisions generally are effective 360 days from the date of enactment, on July 16, 2011. Provisions that require a rulemaking by the Commodities Futures Trading Commission, or the CFTC, and/or the SEC will not take effect until at least 60 days after publication of the related final rule. The CFTC and the SEC have not completed all of the rulemaking the Dodd-Frank Act directs them to carry out. The regulators have granted temporary relief from the general effective date for various requirements of the Dodd-Frank Act, and also have indicated they may phase in implementation of various requirements of the new rules. In its rulemaking under the Dodd-Frank Act, the

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CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivatives activities, although the application of those provisions to us is uncertain at this time. The Dodd-Frank Act may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivatives contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect our business, financial condition or results of operations.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

The Fracturing Responsibility and Awareness of Chemicals Act, or the FRAC Act, was introduced in, but not passed by, the 111th Congress and reintroduced in the 112th Congress, to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. If adopted, such legislation could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Certain states in which we operate, including Texas, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas, or the RCT, and the public disclosure of certain information regarding the components used in the hydraulic-fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct, operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic-fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic-fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands.

Additionally, certain members of the Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural-gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural-gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency s estimates regarding natural-gas reserves, including reserves from shale formations, as well as uncertainties

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associated with those estimates. These on-going or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanism.

Further, on July 28, 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion, or REC, techniques developed in EPA s Natural Gas STAR program along with pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology, or MACT, standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently researching the effect these proposed rules could have on our business. Final action on the proposed rules is expected no later than February 28, 2012.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

Risks Related to Our Common Stock

Failure to obtain a satisfactory result from our strategic alternatives process could adversely affect our common stock price, and our future business and financial results.

On July 20, 2010, following our termination of the Agreement and Plan of Merger with Resaca we announced the initiation of a strategic alternatives process designed to achieve the best available economic value for our shareholders. The strategic alternatives we are considering include the sale of the Company, the sale of some or all of our existing oil and gas properties and assets, or potential business combinations. We currently have a severe shortage of working capital and funds to pay our liabilities, and we currently have no available borrowing capacity under our senior or subordinated credit agreements. We were not in compliance with the interest coverage ratio, leverage ratio, and other requirements of our credit agreements. On August 5, 2010, we finalized Forbearance Agreements with our lenders that set certain deadlines for the execution of our strategic alternatives process and allowed us to sell certain natural gas commodity derivative contracts for $0.8 million. The cash proceeds from the sale of the derivative contracts were expected to provide us sufficient liquidity to complete our strategic alternatives process. The Consent and Forbearance Agreements were terminated as our lenders delivered Reservation of Rights Letters dated September 24, 2010, January 5, 2011, and September 23, 2011. On August 31, 2011, we failed to make a required payment of interest under our senior credit agreement. Our failure to make such payment of interest constituted an Event of Default under our senior and subordinated credit agreements, for which the lenders under such credit agreements may terminate their obligation to extend credit to us and declare all amounts payable under our senior and subordinated credit agreements due and payable in full. We have not received any notice from the lenders with respect to the exercise of their respective rights, including any right to accelerate the amounts payable by us. We continue to work with our lenders and advisors as we consider strategic alternatives. Our Consolidated Financial Statements have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets and liquidation of liabilities in the ordinary course of business. As a result of the losses incurred and current negative working capital, there is no assurance that the carrying amounts of assets will be realized or that liabilities will be liquidated or settled for the amounts recorded. The ability of Cano to continue as a going concern is dependent upon the strategic alternatives process, as previously discussed. There can be no assurance that our strategic alternatives process will adequately resolve issues regarding our liquidity or going concern status.

Our historic stock price has been volatile and the future market price for our common stock may continue to be volatile. This may make it difficult for you to sell our common stock for a positive return on your investment.

The public market for our common stock has historically been very volatile. On October 19, 2011, our closing price on the NYSE Amex was $0.17. Any future market price for our shares may continue to be very volatile. The stock market in general has experienced extreme price and volume fluctuations that often are unrelated or disproportionate to the operating performance of companies. Broad market factors and the investing public s negative perception of our business may reduce

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our stock price, regardless of our operating performance. Market fluctuations and volatility, general economic, market and political conditions, as well as our operating and financial performance, could reduce our stock price. As a result, this may make it difficult or impossible for you to sell our common stock for a positive return on your investment.

If we fail to meet continued listing standards of NYSE Amex or fail to adequately address the low selling price of our common stock, our common stock may be delisted which would have a material adverse effect on the price of our common stock.

In order for our common stock to be eligible for continued listing on NYSE Amex, we must remain in compliance with certain listing standards. Among other things, these standards require that we remain current in our filings with the SEC and comply with certain provisions of the Sarbanes-Oxley Act of 2002. We received a notice on November 10, 2010, from the NYSE Amex LLC (the Exchange) specifying that we did not meet one of the Exchange s continued listing standards in that we failed to hold our 2009 annual meeting of stockholders prior to June 30, 2010. On December 9, 2010, we provided to the Exchange our plan to regain compliance with the continued listing standards by May 10, 2011.

On January 14, 2011, we received notification from the Exchange indicating that the Exchange has determined that we have made a reasonable demonstration of our ability to regain compliance with the continued listing standards and therefore granted us an extension to regain compliance with the applicable listing standard by May 10, 2011. On April 21, 2011, we held our Annual Meeting of Stockholders. On April 25, 2011, we received a letter from the Exchange notifying us that the continued listing deficiency referenced above had been resolved. As a result, the Company has achieved compliance with Section 704 of the AMEX Company Guide, and the Company s common stock continues to trade on the Exchange. However, we cannot assure you that we will maintain compliance with NYSE Amex s continued listing requirements in the future. If we were to again become noncompliant with NYSE Amex s continued listing requirements, our common stock may be delisted which would have a material adverse affect on the price of our common stock.

On October 5, 2011, we received a letter from NYSE Amex informing us that over the 30 trading days immediately preceding the date of such letter, the price of our common stock averaged $0.19 per share, and as of October 4, 2011, it closed at $0.14 per share. The letter constituted notification that the staff of NYSE Regulation s corporate compliance department deems it appropriate for us to effect a reverse stock split. If we do not adequately address our low selling price, through either a reverse stock split or other action, within a reasonable amount of time after such letter, NYSE Amex may initiate delisting proceedings.

If we are delisted from NYSE Amex, our common stock may become subject to the penny stock rules of the SEC, which would make transactions in our common stock cumbersome and may reduce the value of an investment in our stock.

The SEC has adopted Rule 3a51-1 which establishes the definition of a penny stock, for the purposes relevant to us, as any equity security that is not listed on a national securities exchange or registered national securities association s automated quotation system and has a market price of less than $5.00 per share, subject to certain exceptions. For any transaction involving a penny stock, unless exempt, Rule 15g-9 requires:

- that a broker or dealer approve a person s account for transactions in penny stocks; and

- the broker or dealer receives from the investor a written agreement to the transaction, setting forth the identity and quantity of the penny stock to be purchased.

In order to approve a person s account for transactions in penny stocks, the broker or dealer must:

- obtain financial information and other information regarding the investment experience and objectives of the person; and

- make a reasonable determination that the transactions in penny stocks are suitable for that person and the person has sufficient knowledge and experience in financial matters to be capable of evaluating the risks of transactions in penny stocks.

The broker or dealer must also deliver, prior to any transaction in a penny stock, a disclosure schedule prescribed by the SEC relating to the penny stock market, which, in highlight form:

- sets forth the basis on which the broker or dealer made the suitability determination; and

- confirms the broker or dealer received a signed, written agreement from the investor prior to the transaction.

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Generally, brokers may be less willing to execute transactions in securities subject to the penny stock rules. This may make it more difficult for investors to dispose of our common stock and cause a decline in the market value of our stock.

If securities analysts downgrade our stock or cease coverage of us, the price of our stock could decline.

The trading market for our common stock relies in part on the research and reports that industry or financial analysts publish about our business or us. We do not control the reports these analysts publish about us. Furthermore, there are many large, well-established, publicly-traded companies active in our industry and market, which may make it less likely that we will receive widespread analyst coverage. If one or more of the analysts who do cover us downgraded our stock, our stock price would likely decline rapidly. If one or more of these analysts cease coverage of our company, we could lose visibility in the market, which in turn could cause our stock price to decline.

We do not pay dividends on our common stock.

We have never paid dividends on our common stock, and do not intend to pay cash dividends on the common stock in the foreseeable future. Net income from our operations, if any, will be used for the development of our business, including capital expenditures, and to retire debt. Any decisions to pay dividends on the common stock in the future will depend upon our profitability at the time, available cash and other factors. Our ability to pay dividends on our common stock is further limited by the terms of our credit agreements and our Preferred Stock.

Provisions in our corporate governance and loan documents, the terms of our Preferred Stock and Delaware law may delay or prevent an acquisition of Cano, which could decrease the value of our common stock.

Our certificate of incorporation, our Preferred Stock, our bylaws, our credit agreements and the Delaware General Corporation Law contain provisions that may discourage other persons from initiating a tender offer or takeover attempt that a stockholder might consider to be in the best interest of all stockholders, including takeover attempts that might result in a premium to be paid over the market price of our stock.

The terms of our Preferred Stock give its holders the right to have their Preferred Stock redeemed upon a change of control. In addition, the terms of our Preferred Stock do not permit us to enter into certain transactions that would constitute a change of control unless the successor entity assumes all of our obligations relating to the Preferred Stock and the holders of a majority of our Preferred Stock approve such assumption and the successor entity is publicly-traded on the NYSE Amex, the New York Stock Exchange, the Nasdaq Global Select Market, the Nasdaq Global Market or the Nasdaq Capital Market.

In addition, subject to the terms of the Preferred Stock, we are authorized to issue additional shares of preferred stock. Subject to the terms of the Preferred Stock and our certificate of incorporation, our board of directors has total discretion in the issuance and the determination of the rights and privileges of any shares of preferred stock that might be issued in the future, which rights and privileges may be detrimental to the holders of the common stock. It is not possible to state the actual effect of the authorization and issuance of a new series of preferred stock upon the rights of holders of the common stock and other series of preferred stock unless and until the board of directors determines the attributes of any new series of preferred stock and the specific rights of its holders. These effects might include:

- restrictions on dividends on common stock and other series of preferred stock if dividends on any new series of preferred stock have not been paid;

- dilution of the voting power of common stock and other series of preferred stock to the extent that a new series of preferred stock has voting rights, or to the extent that any new series of preferred stock is convertible into common stock;

- dilution of the equity interest of common stock and other series of preferred stock; and

- limitation on the right of holders of common stock and other series of preferred stock to share in Cano s assets upon liquidation until satisfaction of any liquidation preference attributable to any new series of preferred stock.

The terms of our Preferred Stock and the provisions in our corporate governance documents regarding the granting of additional preferred stock may deter or render more difficult proposals to acquire control of our company, including proposals a stockholder might consider to be in his or her best interest, impede or lengthen a change in membership of our Board of Directors and make removal of our management more difficult. Furthermore, Delaware law imposes some restrictions on mergers and other business combinations between our company and owners of 15% or more of our common

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stock. These provisions apply even if an acquisition proposal is considered beneficial by some stockholders and therefore could depress the value of our common stock.

The conversion price of our Preferred Stock may be lowered if we issue shares of our common stock at a price less than the existing conversion price, which could cause further dilution to our common stockholders.

Subject to certain exclusions, if we issue common stock at a price less than the existing conversion price for our Preferred Stock, the conversion price shall be adjusted downward which would further dilute our common stock holders upon conversion.

Our Preferred Stock has voting rights both together with and separate from our common stock, which could adversely affect our common stockholders.

The holders of our Preferred Stock vote together with the holders of our common stock on an as-converted basis, subject to a limitation on how many votes the Series D Convertible Preferred Stock holders may cast if the conversion price falls below $4.79. In addition, approval of holders of a majority of the Series D Convertible Preferred Stock is required for us to take the following actions:

- to modify the certificate of incorporation or bylaws in a manner adverse to the Preferred Stock;
- increase or decrease the number of authorized shares of Preferred Stock;
- create any class of preferred stock that has a preference over or is in parity with the Preferred Stock with respect to dividends or liquidation;
- purchase, repurchase or redeem any share of common stock;
- pay dividends or make any other distribution on the common stock; or
- circumvent a right of the Preferred Stock.

These voting rights may have an adverse impact on the common stock and the voting power of our common stockholders.

Since we are a United States real property holding corporation, non-U.S. investors may be subject to U.S. federal income tax (including withholding tax) on gains realized on disposition of our shares, and U.S. investors selling our shares may be required to certify as to their status in order to avoid withholding.

Since we are a United States real property holding corporation, a non-U.S. holder of our common stock will generally be subject to U.S. federal income tax on gains realized on a sale or other disposition of our common stock. Certain non-U.S. holders of our common stock may be eligible for an exception to the foregoing general rule if our common stock is regularly traded on an established securities market during the calendar year in which the sale or disposition occurs. However, we cannot offer any assurance that our common stock will be so traded in the future.

If our common stock is not considered to be regularly traded on an established securities market during the calendar year in which a sale or disposition occurs, the buyer or other transferee of our common stock will generally be required to withhold tax at the rate of 10% of the sales price or other amount realized, unless the transferor furnishes an affidavit certifying that it is not a foreign person in the manner and form specified in applicable Treasury regulations.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

See Items 1 and 2. Business and Properties.

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Item 3. Legal Proceedings.

Our operations are subject to a variety of risks and disputes normally incident to our business. As a result, we are and may, at any given time, be a defendant in various legal proceedings and litigation arising in the ordinary course of business. We maintain insurance policies with insurers in amounts and with coverage and deductibles that we, with the advice of our insurance advisors and brokers, believe are reasonable and prudent. We cannot, however, assure you that this insurance will be adequate to protect us from all material expenses related to current and potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

Resaca Claim

Section 7.6 of the Merger Agreement with Resaca Exploitation, Inc. (Resaca) provided for the Company and Resaca to share transaction expenses related to the printing, filing and mailing of the registration statement on Form S-4 covering the Resaca shares that would have been issued to Cano stockholders in the merger, the proxy statements relating to the meetings at which the stockholders of Cano and Resaca voted to approve the merger, and the solicitation of stockholder approvals. On September 2, 2010, we filed an action against Resaca in the Tarrant County District Court seeking a declaratory judgment to clarify the scope and determine the amount of any expenses that are reimbursable under Section 7.6 of the Merger Agreement. On December 16, 2010, the presiding District Court judge denied Resaca s request to transfer the venue. On January 19, 2011, Resaca filed a motion for Partial Summary Judgment to seek reimbursement of certain merger-related expenses totaling $1.1 million, for which Cano s 50% portion would be $0.5 million. On April 14, 2011, the presiding judge denied Resaca s request for Partial Summary Judgment. Mediation on July 13, 2011, did not resolve differences. Based on our knowledge and judgment of the facts as of October 20, 2011, our financial statements dated June 30, 2011, present fairly the effect of the actual and the anticipated future costs to resolve this matter.

Greenhaw Litigation

On August 14, 2009, Chimo Properties, Ltd. and Morris R. Greenhaw sued Square One Energy, Inc., our subsidiary, in the 91st District Court Eastland County, Texas, alleging that Square One Energy, Inc. conducted its oil and gas operations negligently, resulting in surface damages to the plaintiffs ranch. The plaintiffs are seeking money damages of approximately $1.6 million. We have been vigorously defending, and will continue to vigorously defend, against plaintiffs claims. A memorandum of settlement has been signed and a final settlement is being negotiated. Based on our knowledge and judgment of the facts as of October 20, 2011, our financial statements dated June 30, 2011, present fairly the effect of the actual and the anticipated future costs to resolve this matter.

Johnson Wage Claim

On August 19, 2011, Jeffrey Johnson, our former Chief Executive Officer, filed an administrative wage claim against us with the Texas Workforce Commission (TWC). In the claim, Johnson requested $643,574.06 in (1) unpaid severance and car allowance payments allegedly due under his employment agreement, (2) payment for accrued unused vacation since 2006 allegedly due under his employment agreement, (3) unpaid health care coverage premiums for six months allegedly due under his employment agreement, and (4) statutory interest. We filed a response to the TWC on September 19, 2011 that disputed the amount of the wage claim above what was due under the terms of Mr. Johnson s employment agreement in connection with the termination of his employment without cause and requested an offset for alleged personal charges on Mr. Johnson s company credit card. On September 22, 2011, the TWC issued a Preliminary Wage Determination Order (PWDO) that Mr. Johnson is entitled to $329,427.04 (consisting of $312,067.99 in unpaid severance pay and $17,359.05 in unpaid vacation pay). The deadline for either party to appeal the PWDO to the TWC s Special Hearings Department was October 13, 2011. We did not file an appeal. If Johnson has not filed an appeal, the TWC advises that the PWDO will become final on October 23, 2011 and will be eligible for collection at that time. Based on our knowledge and judgment of the facts as of October 20, 2011, our financial statements dated June 30, 2011, present fairly the effect of the actual and the anticipated future costs to resolve this matter.

Other

Occasionally, we are involved in other various claims and lawsuits and certain governmental proceedings arising in the ordinary course of business. Our management does not believe that the ultimate resolution of any current matters that are not set forth above will have a material effect on our financial position or results of operations. Management s position is supported, in part, by the existence of insurance coverage, indemnification and/or escrow accounts. None of our directors,

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officers or affiliates, owners of record or beneficial owners of more than five percent of any class of our voting securities, or security holder is involved in a proceeding adverse to us or our subsidiaries or has a material interest adverse to our subsidiaries or us.

Environmental

To date, our expenditures to comply with environmental or safety regulations have not been significant and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

Item 4. (Removed and Reserved).

PART II

Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Market Information

Our shares of common stock are listed on the NYSE Amex under the trading symbol CFW. For the years ended June 30, 2010, and 2011, the following table sets forth the high and low sales prices per share of common stock for each quarterly period. On October 19, 2011, the closing sale price of our common stock on the NYSE Amex was $0.17.

	Fiscal 2011		Fiscal 2010	
	High	Low	High	Low
Fiscal Quarter				
First Quarter Ended September 30	$ 0.89	$ 0.41	$ 1.37	$ 0.52
Second Quarter Ended December 31	$ 0.51	$ 0.29	$ 1.31	$ 0.79
Third Quarter Ended March 31	$ 0.70	$ 0.31	$ 1.22	$ 0.76
Fourth Quarter Ended June 30	$ 0.59	$ 0.33	$ 1.25	$ 0.66

Holders

As of October 19, 2011, our shares of common stock were held by approximately 100 stockholders of record. In many instances, a record stockholder is a broker or other entity holding shares in street name for one or more customers who beneficially own the shares. We estimate that, as of the record date for the last meeting of shareholders, March 22, 2011, there were approximately 8,760 beneficial holders who own shares of our common stock in street name.

Dividends

We have not declared any dividends to date on our common stock. We have no present intention of paying any cash dividends on our common stock in the foreseeable future, as we intend to reinvest earnings, if any, into our operations. Our credit agreements do not permit us to pay dividends on our common stock.

During the year ended June 30, 2011, there were no equity securities issued pursuant to transactions exempt from registration requirements under the Securities Act of 1933, as amended, that were not disclosed previously in Current Reports on Form 8-K or Quarterly Reports on Form 10-Q.

Item 6. Selected Financial Data.

Not applicable.

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain of the matters discussed under the captions Business and Properties, Legal Proceedings, Management s Discussion and Analysis of Financial Condition and Results of Operations, and elsewhere in this annual report may constitute forward-looking statements for purposes of the Securities Act of 1933, and the Securities Exchange Act of 1934 and, as such, may involve known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements to be materially different from future results, performance or achievements expressed or

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implied by such forward-looking statements. When used in this report, the words anticipates, estimates, plans, believes, continues, expects, projections, forecasts, intends, may, might, could, should, and similar expressions are intended to be among the statements that identify forward-looking statements. Various factors could cause the actual results, performance or achievements to differ materially from our expectations. When considering our forward-looking statements, keep in mind the risk factors and other cautionary statements disclosed in this annual report (Cautionary Statements), including, without limitation, those statements made in conjunction with the forward-looking statements included under the captions identified above and otherwise herein. All written and oral forward-looking statements attributable to us are qualified in their entirety by the Cautionary Statements. We do not undertake any obligation to update or revise publicly any forward-looking statements, except as required by law and you are cautioned not to place undue reliance on any forward-looking statement.

Overview

Introduction

We are an independent oil and natural gas company. In the past, our strategy had been to convert our proved undeveloped reserves into proved producing reserves, improve operational efficiencies in our existing properties and acquire accretive proved producing assets suitable for secondary and enhanced oil recovery at low cost. Due to the Company s current financial constraints, including continued losses, defaults under our loan agreements and our Series D Preferred Stock, no available borrowing capacity, constrained cash flow, negative working capital, and limited to no other capital availability, we are reviewing strategic alternatives which include the sale of the Company, the sale of some or all of our existing oil and gas properties and assets, potential business combinations, debt restructuring, including recapitalizing the Company, and bankruptcy. We continue to focus on cash management and cost reduction efforts to improve both our cash flow from operations and profitability. Our assets are located onshore in the U.S. in Texas, New Mexico, and Oklahoma.

During our first three years of operations, our primary objective was to achieve growth through acquiring existing, mature crude oil and natural gas fields. Since then, we have focused on waterflood operations in our two largest properties, Panhandle and Cato. These development activities are more clearly described below under *Drilling Capital Development and Operating Activities Update.*

As discussed under *Liquidity / Going Concern,* on July 20, 2010, we terminated our announced merger with Resaca Exploitation, Inc. (Resaca) that had been initiated pursuant to an Agreement and Plan of Merger dated September 29, 2009. On July 26, 2010, we announced the engagement of Canaccord Genuity Inc. and Global Hunter Securities to assist our management and board of directors in a review of strategic alternatives. That review is ongoing. However, even if we are able to execute successfully one of our strategic alternatives, we may not be able to meet our obligations as they become due and to continue as a going concern.

Proved Reserves

Haas Petroleum Engineering Services, Inc., our independent reserves engineers, has prepared our estimates of proved oil and natural gas reserves as of June 30, 2011. The following table compares our estimated proved reserves by property as of June 30, 2011, to June 30, 2010. The amounts are presented in thousands of barrels oil equivalent (MBOE).

(in MBOE)	**June 30, 2011**				**June 30, 2010**			
Properties	**PDP**	**PDNP**	**PUD**	**Proved**	**PDP**	**PDNP**	**PUD**	**Proved**
Panhandle	1,517			1,517	2,389		20,990	23,379
Cato	419			419	921	719	13,194	14,834
Nowata	1,678			1,678	1,839	50		1,889
Davenport	663			663	696	507		1,203
Desdemona	2			2	196	978		1,174
Total Proved Reserves	4,279			4,279	6,041	2,254	34,184	42,479

On an MBOE basis, estimated crude oil reserves accounted for 84% of our total proved reserves at June 30, 2011.

The reserve estimates as of June 30, 2011, and June 30, 2010, were made in accordance with the SEC s final rule, *Modernization of Oil and Gas Reporting,* issued in December 2008 and effective for annual reports on Form 10-K for years ending on or after December 31, 2009, which amended Rule 4-10 of Regulation S-X (the Final Rule).

As of June 30, 2011, our proved reserves totaled 3,592 MBbls and 4,123 MMcf (equivalent to approximately 4,279

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MBOE). This is 29,508 MBbls and 52,151 MMcf (equivalent to approximately 38,200 MBOE) lower than our estimated proved reserves of 33,100 MBbls and 56,274 MMcf (equivalent to approximately 42,479 MBOE) at June 30, 2010. Separate estimated reserves are not reported for NGLs; instead, estimated natural gas reserves are reported on a wet basis that include the NGLs subsequently removed from the gas stream.

The primary contributors to the decrease are:

- production of 264 MBbls and 574 MMcf (equivalent to approximately 359 MBOE)
- reduced estimated PDP reserves (adjusted for production) at the Panhandle, Cato, and Desdemona Properties of 882 MBbls and 2,390 MMcf (equivalent to approximately 1,316 MBOE)
- reduced estimated PUD reserves at the Panhandle and Cato Properties of 26,975 MBbls and 43,251 MMcf (equivalent to approximately 34,184 MBOE)
- reduced estimated PDNP reserves (including estimated Proved behind-pipe reserves) at the Cato, Davenport, and Desdemona Properties of 1,269 MBbls and 4,524 MMcf (equivalent to approximately 2,204 MBOE).

Proved Developed Producing Reserves

The following table summarizes the changes in our estimated proved developed reserves from June 30, 2010, to June 30, 2011.

Summary of Changes in Estimated Proved Developed Reserves	**MBOE**
Estimated Reserves at June 30, 2010	6,041
Reserves Revisions	(1,403)
Production for the year ended June 30, 2011	(359)
Estimated Reserves at June 30, 2011	**4,279**

Most of the revisions to our estimated proved developed producing reserves are a result of disruptions in production due to events outside the control of the company. The October 2010 fire in the Cato Field was caused by lightning, and this event not only caused an immediate impact on production, but it has also resulted in a prolonged reduction in production. The Cato waterflood was suspended for 30 days and field production declined as a result. Once injection was returned to previous levels, production has not returned to pre-fire levels. To compound the problem, a variety of mechanical and electrical issues have hampered the company s ability to improve production. Due to the production decline, Haas reduced the estimated PDP reserves projection by placing it immediately on decline. Previously, based on Cano s analytical waterflood models, the production had been held flat for several years, and then placed on decline. Haas reduced our estimated PDP reserves of the Cato properties by 431 MBOE.

During the first quarter of the 2011 Fiscal Year, we reduced the rate of water injection at the Cockrell Ranch and Harvey Ranch units to gain improved operational efficiencies and because of capital constraints. Consequently, the production for these Panhandle properties declined at a quicker pace than previously estimated. Due to the decline in production, Haas reduced our estimated PDP reserves of the Panhandle properties by 718 MBOE.

Desdemona reserve revisions are relatively insignificant for the company as a whole. However, operating costs increased and gas production fell below the estimates used to prepare our 2010 reserves report. Haas reduced our estimated PDP reserves of the Desdemona properties by 167 MBOE.

Haas made no significant changes to the estimated reserves for the Davenport and Nowata properties.

Capital constraints during this reporting period have inhibited the Company s ability to enhance and fully maintain production.

Our operational and development activities are more fully described below under *Development Capital Expenditures and Operating Activities Update.*

Proved Undeveloped Reserves and Proved Developed Non-Producing Reserves

As of June 30, 2011, the Company has no reportable estimated proved undeveloped reserves or estimated proved developed non-producing reserves. This is a decrease of 27.0 MMBO and 43.3 MMCF (equivalent to approximately 34.2 MMBOE) from the estimated proved undeveloped reserves and a decrease of 1.3 MMBO and 5.7 MMCF (equivalent to

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approximately 2.3 MMBOE) from the estimated proved developed non-producing reserves reported by the Company as of June 20, 2010.

The decreases in estimated PUD and estimated PDNP reserves are the result of the application of the requirements of the previously cited Final Rule. Among other things, guidance for the Final Rule for the reporting of estimated proved undeveloped requires that a company must have adopted a development plan and have made a final investment decision for their development. The mere intent to develop is not sufficient for reporting estimated proved undeveloped reserves. For all estimated reserves, the Final Rule requires that there must exist, or there must be a reasonable expectation that there will exist, the financing required to implement the development projects. The capital requirement for development of the estimated PUD and estimated PDNP reserves previously reported by the Company as of June 30, 2010, was estimated to be approximately $303.5 million, and approximately $7.0 million, respectively. Due to the Company s current financial constraints, including continued losses, defaults under our loan agreements and our Series D Preferred Stock, no available borrowing capacity, constrained cash flow, negative working capital, and limited to no other capital availability, there is not a reasonable expectation that the Company can obtain the financing required to implement these projects within a reasonable time, even though we believe these projects, in and of themselves, remain technically feasible and economically attractive. Therefore, we have recorded the aforementioned reduction to our estimated reserves.

The prices used to compute our estimated proved reserves are determined as an un-weighted arithmetic average of the first-day-of-the-month price for each month for the past twelve fiscal months ended June 30, 2011, unless prices are defined by contractual arrangements. For the period ending June 30, 2011, we have computed the un-weighted average first-day-of-the-month NYMEX crude oil and natural gas prices to be $90.09 per barrel and $4.21 per MMBTU, respectively as compared to the June 30, 2010, prices of $75.76 per barrel and $4.10 per MMBTU. Adjusting for BTU content (including NGL content), basis differentials, marketing costs and fees, crude oil quality, and transportation costs, the average net prices realized by the Company are $84.14 per barrel and $8.48 per MCF, respectively, as compared to $68.98 per barrel and $7.59 per MCF for the period ended June 30, 2010.

The table below summarizes the changes in our estimated proved reserves from June 30, 2010, to June 30, 2011.

Summary of Changes in Estimated Proved Reserves	**MBOE**
Estimated Reserves at June 30, 2010	42,479
Revisions of prior estimates	(37,841)
Production for the year ended June 30, 2011	(359)
Estimated Reserves at June 30, 2011	4,279

Our development activities are more fully described below under *Development and Operating Activities Update.*

Development and Operating Activities Update

For the quarter ending June 30, 2011 (current quarter) our production averaged 976 net BOEPD (721 net barrels of oil per day and 1,530 net Mcf per day) which was 173 net BOEPD (15.1%) lower as compared to production of 1,149 BOEPD (820 net barrels of oil per day and 1,974 net Mcf per day) for the quarter ended June 30, 2010 (prior year quarter). Production for the year ended June 30, 2011 (2011 Fiscal Year) of 984 net

BOEPD (722 net barrels of oil per day and 1,573 net Mcf per day) was 118 net BOEPD (10.7%) lower as compared to the year ended June 30, 2010, of 1,102 net BOEPD (796 net barrels of oil per day and 1,840 net Mcf per day). For both the current quarter and 2011 Fiscal Year, the production decreases were primarily attributed to the fire at our Cato Properties and the suspension of the Panhandle waterfloods, as discussed below. Normal field production declines contributed as well.

For the 2011 Fiscal Year, we incurred development capital expenditures of $1.2 million (excluding capitalized general and administrative and interest expenses). Our capital budget was designed to address maintenance operations primarily at our Cato, Panhandle, and Desdemona Properties. The company s development capital expenditure cost, were incurred as follows:

- $0.8 million at the Cato Properties,

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- $0.2 million at the Panhandle Properties, and
- $0.2 million at the Desdemona Properties.

The following is a discussion of our field level activity during the 2011 Fiscal Year.

Cato Properties.

On May 6, 2010, we received administrative approval from the New Mexico Oil and Gas Conservation Division (NMOGCD) to increase injection pressures at the 14 active injection wells. On August 5, 2010, we received an expansion permit from the NMOGCD, to further expand the waterflood operations. As a result, we increased water injection rates at Phase 1 of the waterflood project at the Cato Properties.

During mid-October 2010, production was adversely affected by a weather-related electrical outage. Production was shut-in for 30 days, which resulted in lost production averaging 82 BOEPD during the quarter ended December 31, 2010, as compared to the prior quarter. During the outage, we installed larger electric submersible pumps (ESP s) in both existing and return to production (RTP) wells and implemented necessary facility upgrades to optimize our infrastructure. We have seen increased fluid production rates and corresponding increasing crude oil rates as a direct result of this work. Net production for the current quarter and 2011 Fiscal Year was 205 BOEPD and 196 BOEPD, respectively. Net production for the prior year quarter and 2010 Fiscal Year was 237 BOEPD and 258 BOEPD, respectively. Additional analysis and field work are necessary to optimize the waterflood operation. In addition, further development plans for the waterflood and for the Queen Sands formation have been postponed due to capital constraints. For the period from September 16 through September 30, 2011, the Bureau of Land Management issued an order suspending operations at the Cato Properties until we could establish to the Bureau s satisfaction that we are substantially in compliance with the Bureau s operating and environmental guidelines. Effective October 1, 2011, the Bureau approved resumption of production at the Cato Properties.

Please see *Business Properties* *Our Properties* *Cato Properties* for a description of the Cato Properties.

Panhandle Properties.

During the first quarter of the 2011 Fiscal Year, we reduced the rate of water injection at the Cockrell Ranch and Harvey Ranch units to improved operational efficiencies and because of capital constraints. Although this resulted in lost production of 30 BOEPD, operating margins have improved. Our natural gas production decreases for both the current quarter and current year resulted from intermittent gas plant outages by DCP Midstream, L.P., which adversely affected our production, and from inclement weather, which temporarily curtailed production. Net production for the current quarter and 2011 Fiscal Year was 409 BOEPD and 421 BOEPD, respectively. Net production for the prior year quarter and 2010 Fiscal Year was 546 BOEPD and 494 BOEPD, respectively.

Please see *Business Properties* *Our Properties* *Panhandle Properties* for a description of the Panhandle Properties.

Desdemona Properties.

During the 2011 Fiscal Year, we activated RTP wells and completed upgrades to our gas plant to sell all natural gas and natural gas liquids produced from the Duke Sand formation and new production from behind-pipe completions in the Atoka formation. Through December 31, 2010, we had returned to production ten wells in the Duke Sand formation and recompleted two wells in the Atoka formation. Each Atoka well recompletion had initial production of 125 Mcfd (21 BOEPD) and stabilized at 45-50 Mcfd (6 BOEPD). Net production for the current quarter and 2011 Fiscal Year was 78 BOEPD and 75 BOEPD, respectively. Net production for the prior year quarter and 2010 Fiscal Year was 69 BOEPD and 55 BOEPD, respectively.

Please see *Business Properties* *Our Properties* *Desdemona Properties* for a description of the Desdemona Properties.

Nowata Properties.

We are currently assessing the viability of increasing production by expanding the gas gathering system to connect additional wells to increase casinghead gas sales and optimizing current infrastructure. During June 2011, our production averaged 225 BOEPD at the Nowata Properties, and has remained relatively flat since its acquisition in September 2004. Net production for the current quarter and 2011 Fiscal Year was 212 BOEPD and 215 BOEPD, respectively. Net production for the prior year quarter and 2010 Fiscal Year was 219 BOEPD and 219 BOEPD, respectively.

Please see *Business Properties* *Our Properties* *Nowata Properties* for a description of the Nowata Properties.

Davenport Properties.

Net production for the current quarter and 2011 Fiscal Year was 72 BOEPD and 78 BOEPD, respectively. Net production for the prior year quarter and 2010 Fiscal Year was79 BOEPD and 76 BOEPD, respectively.

Please see *Business Properties* *Our Properties* *Davenport Properties* for a description of the Davenport Properties.

Industry Conditions

We operate in a competitive environment for (i) acquiring properties, (ii) marketing oil and natural gas and (iii) attracting trained personnel. Some of our competitors possess and employ financial resources substantially greater than ours and some of our competitors employ personnel that are more technical. Some of our competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than what our financial or technical resources permit. Our ability to acquire additional properties and to find and develop reserves in the future will depend on our ability to identify, evaluate and obtain capital for investment in the oil and natural gas industry.

EOR techniques involve significant capital investment and an extended period of time, generally a year or longer, until production increases. Our ability to successfully convert estimated PUD reserves to estimated PDP reserves will be contingent upon our ability to obtain future financing and/or raise additional capital. Further, there are inherent uncertainties associated with the production of crude oil and natural gas, as well as price volatility. See *Item 1A.Risk Factors.*

Liquidity and Capital Resources

Liquidity / Going Concern

Due to the Company s current financial condition, including continued losses, defaults under our loan agreements and our Series D Preferred Stock, no available borrowing capacity, constrained cash flow, negative working capital, and limited to no access to additional capital, the report of our independent registered public accounting firm dated October 20, 2011, relating to our consolidated financial statements includes an emphasis paragraph relating to uncertainties as to our ability to continue as a going concern.

At June 30, 2011, we had cash and cash equivalents of $1.7 million. We had negative working capital of $106.1 million, which includes $66.5 million of long-term debt that was shown as a current liability plus $28.9 million of our Series D convertible preferred stock that was also shown as a current liability.

On July 20, 2010, we terminated our announced merger with Resaca Exploitation, Inc. (Resaca) that had been initiated pursuant to an Agreement and Plan of Merger dated September 29, 2009. On July 26, 2010, we announced the engagement of Canaccord Genuity Inc. and Global Hunter Securities to assist our management and board of directors in a review of strategic alternatives with the goal of maximizing economic value for our stakeholders. We believe that these alternatives include the following: sale of the Company; sale of some or all of our existing oil and gas properties and assets; business combinations; debt restructuring, including recapitalizing the Company, with or without bankruptcy; and bankruptcy. That review is ongoing. However, even if we are able to execute successfully one of our strategic alternatives, we may not be able to meet our obligations as they become due and to continue as a going concern.

On August 5, 2010, we finalized Consent and Forbearance Agreements with the lenders under our credit agreements that waived potential covenant compliance issues for the periods ending June 30, 2010, and September 30, 2010, set certain deadlines for the execution of our strategic alternatives process and allowed us to sell certain natural gas commodity derivative contracts for cash proceeds of $0.8 million, which was intended to provide Cano sufficient liquidity to complete its strategic alternatives process. The Consent and Forbearance Agreements were terminated as our lenders delivered Reservation of Rights Letters dated September 24, 2010, January 5, 2011, and September 23, 2011. We continue to work with our lenders and advisors as we consider strategic alternatives. As of October 19, 2011, our lenders have taken no definitive actions associated with the termination of the

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Consent and Forbearance Agreements. We currently have no available borrowing capacity under our senior and subordinated credit agreements.

The accompanying consolidated financial statements have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets and liquidation of liabilities in the ordinary course of business. There is no assurance that the carrying amounts of assets will be realized or that liabilities will be settled for the amounts recorded, or that the Company can continue to prepare future financial statements on a going concern basis. The ability of the Company to continue as a going concern will be dependent upon the outcome of our strategic alternatives review, crude oil and natural gas prices, sufficient liquidity to fund operations, actions by our lenders, mechanical problems at our wells and/or catastrophic events such as fires, hurricanes and floods.

Our universal shelf registration statement, declared effective by the SEC on December 28, 2007 for the issuance of common stock, preferred stock, warrants, senior debt and subordinated debt up to an aggregate amount of $150.0 million, expired on December 31, 2010.

Credit Agreements

At June 30, 2011, the outstanding amount due under our credit agreements was $66.5 million. The $66.5 million consisted of outstanding borrowings under the amended and restated credit agreement (the ARCA) and the subordinated credit agreement (the SCA) of $51.5 million and $15.0 million, respectively. On August 22, 2011, our commodity hedges with the lenders were terminated at a cost of $3.65 million. On September 9, 2011, our interest rate hedge with the lenders was terminated at a cost of $145,500. Both of these amounts have become senior obligations of the Company in addition to the amounts owed under the ARCA. At June 30, 2011, the average interest rates charged by the lenders under the ARCA and SCA were 2.94% and 6.11%, respectively. As of September 12, 2011, we received notice from the agent for the ARCA that the outstanding Libor based loan advances under the ARCA will be converted to prime based advances as they mature. The Company has no borrowing capacity under either the ARCA or SCA.

The ARCA and SCA are discussed in greater detail below.

Forbearance Agreements

On August 5, 2010, we executed a Consent and Forbearance Agreement (the Senior Forbearance Agreement) with Union Bank, N.A. (UBNA) and Natixis relating to existing and potential defaults under the ARCA dated December 17, 2008 among Cano, UBNA and Natixis and a Consent and Forbearance Agreement (together with the Senior Forbearance Agreement, the Forbearance Agreements) with UnionBanCal Equities, Inc. (UBE), relating to existing defaults under the SCA dated December 17, 2008 between Cano and UBE (as amended, the SCA and together with the ARCA, the Credit Agreements). Pursuant to the Forbearance Agreements, Natixis, UBNA and UBE agreed to forbear from exercising certain rights and remedies under the Credit Agreements arising as a result of certain defaults.

On September 24, 2010, our lenders delivered Reservation of Rights Letters (Letters), subsequently updated on January 5, 2011and September 23, 2011, specifying that we failed to timely comply with the material terms of the Forbearance Agreements and therefore terminated the Forbearance Agreements. On August 31, 2011, we failed to make a required payment of interest under the ARCA. Our failure to make such payment of interest constituted an Event of Default under the ARCA and the SCA, for which the lenders under such credit agreements may terminate their obligation to extend credit to us and declare all amounts payable under the ARCA and the SCA due and payable in full. We have not received any notice from the lenders with respect to the exercise of their respective rights, including any right to accelerate the amounts payable by us. We continue to work with our lenders and advisors as we consider strategic alternatives.

We have recorded all additional interest and fees due under the terms of the Credit Agreements of $3.0 million in accrued liabilities on our consolidated balance sheet and in interest expense on consolidated statement of operations as of June 30, 2011. We have also recorded additional interest expense associated with the accelerated amortization of deferred financing costs of $0.9 million applicable to the Credit Agreements, and accounting and legal expense incurred by our lenders of $0.7 million.

The ARCA and SCA are discussed in greater detail below.

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ARCA

On December 17, 2008, we finalized a $120.0 million Amended and Restated Credit Agreement (the ARCA) with UBNA and Natixis. UBNA is the Administrative Agent and Issuing Lender of the ARCA. The current amount outstanding under the ARCA is equal to the commitment of $51.5 million. Further, $3.8 million of costs for the termination of our commodity hedges and interest rate hedge on August 22, 2011, and September 9, 2011, respectively are additional senior obligations of the Company. We are deemed fully borrowed and have no further borrowing capacity under the ARCA. As of September 12, 2011, we received notice from the agent for the ARCA that the outstanding Libor based loan advances under the ARCA will be converted to prime based advances as they mature.

Unless specific events of default occur, the maturity date of the ARCA is December 17, 2012. Specific events of default which could cause all outstanding principal and accrued interest to be accelerated, include, but are not limited to, payment defaults, material breaches of representations and warranties, breaches of covenants, certain cross-defaults, insolvency, a change in control or a material adverse change. If the bank causes all outstanding principal and accrued interest to be accelerated, we will likely be forced to file for bankruptcy or similar protection, unless we are able to successfully execute one of our strategic alternatives, restructure our existing indebtedness, obtain further waivers or forbearance from our existing lenders or otherwise raise significant additional capital. The ARCA contains certain negative covenants including, subject to certain exceptions, covenants against the following: (i) incurring additional liens, (ii) incurring additional debt or issuing additional equity interests other than common equity interests; (iii) merging or consolidating or selling, leasing, transferring, assigning, farming-out, conveying or otherwise disposing of any property, (iv) making certain payments, including cash dividends to our common stockholders, (v) making any loans, advances or capital contributions to, or making any investment in, or purchasing or committing to purchase any stock or other securities or evidences of indebtedness or interest in any person or oil and gas properties or activities related to oil and gas properties unless (a) with regard to new oil and gas properties, such properties are mortgaged to UBNA, as administrative agent, or (b) with regard to new subsidiaries, such subsidiaries execute a guaranty, pledge agreement, security agreement or mortgage in favor of UBNA, as administrative agent, and (vi) entering into affiliate transactions on terms that are not at least as favorable to us as comparable arm s length transactions.

SCA

On December 17, 2008, we finalized a $25.0 million SCA between Cano and UBE, as the Administrative Agent. On March 17, 2009, we borrowed the maximum available amount of $15.0 million under this agreement.

The interest rate is the sum of (a) the one, two or three month LIBOR rate (at our option) and (b) 6.0%. Through March 17, 2009, we owed a commitment fee of 1.0% on the un-borrowed portion of the available borrowing amount. We no longer have a commitment fee since we borrowed the full $15.0 million available amount.

Unless specific events of default occur, the maturity date is June 17, 2013. Specific events of default which could cause all outstanding principal and accrued interest to be accelerated, include, but are not limited to, payment defaults, material breaches of representations and warranties, breaches of covenants, certain cross-defaults, insolvency, a change in control or a material adverse change as defined in the SCA. If the bank causes all outstanding principal and accrued interest to be accelerated, we will likely be forced to file for bankruptcy or similar protection, unless we are able to successfully execute one of our strategic alternatives, restructure our existing indebtedness, obtain further waivers or forbearance from our existing lenders or otherwise raise significant additional capital. The SCA contains certain negative covenants including, subject to certain exceptions, covenants against the following: (i) incurring additional liens, (ii) incurring additional debt or issuing additional equity interests other than common equity interests of Cano; (iii) merging or consolidating or selling, leasing, transferring, assigning, farming-out, conveying or otherwise disposing of any property, (iv) making certain payments, including cash dividends to our common stockholders,

(v) making any loans, advances or capital contributions to, or making any investment in, or purchasing or committing to purchase any stock or other securities or evidences of indebtedness or interest in any person or oil and gas properties or activities related to oil and gas properties unless (a) with regard to new oil and gas properties, such properties are mortgaged to UBE, as administrative agent, or (b) with regard to new subsidiaries, such subsidiaries execute a guaranty, pledge agreement, security agreement or mortgage in favor of UBE, as administrative agent, and (vi) entering into affiliate transactions on terms that are not at least as favorable to us as comparable arm s length transactions.

Credit Agreement Covenant Compliance

At June 30, 2011, we were not in compliance with the ARCA and SCA covenants for Modified Current Ratio, Leverage Ratio or Interest Coverage Ratio.

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The following chart shows the required credit agreement covenant ratios that we must maintain under the ARCA and SCA and our corresponding ratios as of June 30, 2011.

	Ratio Required by the ARCA and SCA	**Our Ratio as of June 30, 2011**
Modified Current Ratio	Must exceed 1.00 (both)	0.12
Leverage Ratio	Cannot exceed 4.00 (ARCA) and 4.50 (SCA)	14.84
Interest Coverage Ratio	Must exceed 3.00 (ARCA) and 2.50 (SCA)	0.63

Both the ARCA and the SCA have a current ratio covenant that requires us to maintain a ratio of not less than 1.00 to 1.00 for each fiscal quarter. The current ratio is calculated by dividing current assets (as defined in both credit agreements) by current liabilities (as defined in both credit agreements). Current assets include unused borrowing base under the ARCA and the aggregate availability under the SCA. Current liabilities exclude all current portions of long-term debt other than any current debt relating to the Preferred Stock and liabilities for asset retirement obligations. Current assets and current liabilities exclude derivative assets and liabilities. At June 30, 2011, our ratio of current assets to current liabilities was 0.12 to 1.00. The calculation and reconciliation of current assets and current liabilities, as defined by GAAP, to current assets and current liabilities, as defined in the credit agreements is as follows:

(in thousands)		**June 30, 2011**
Current assets (GAAP)	$	4,688
Unused borrowing base at June 30, 2011		(1)
Less: derivative assets		
Modified current assets (non-GAAP)	$	4,688(A)
Current liabilities (GAAP)	$	110,763
Less: current portion of long-term debt		(66,450)
Less: derivative liabilities		(5,292)
Less: asset retirement obligation		(208)
Modified current liabilities (non-GAAP)	$	38,813(B)
Modified current ratio (A) / (B)		0.12 to 1.00

(1) We have no further borrowing capacity under the ARCA or SCA.

We were not in compliance with the covenants relating to our leverage ratio and interest coverage ratio for the quarter ended June 30, 2011. The leverage ratio is the ratio of consolidated Debt (as defined in both credit agreements) to consolidated EBITDA (as defined in both credit agreements) for the cumulative four fiscal quarter periods. Under the ARCA and SCA, the leverage ratio cannot be greater than 4.00 to 1.00 and 4.50 to 1.00, respectively. At June 30, 2011, this ratio equaled 14.8. The interest coverage ratio is the ratio of consolidated EBITDA (as defined in both credit agreements) to modified interest expense (as calculated below) for the cumulative four fiscal quarter periods. Under the ARCA and SCA, the interest coverage ratio cannot be less than 3.00 to 1.00 and 2.50 to 1.00, respectively. At June 30, 2011, this ratio equaled 0.70. The calculation and reconciliation of net income and interest expense, as defined by GAAP, to EBITDA and modified interest expense is as follows:

(in thousands)	**June 30, 2011**

Net income (loss) - from continuing operations	$	(185,701)
Add: Income from Discontinued Operations - after-tax		
Add: Interest expense		6,516
Add: Federal income taxes		(18,975)
Add: Depreciation Depletion		19,849
Add: Accretion of ARO		338
Add: Stock based compensation		(579)
Add: Impairment of long-lived properties		172,890
Add: Impairment of Goodwill		
Add: Exploration Expense		
Add: Sale of properties		822
Add: Unrealized loss (gain) on hedging contracts		9,318
EBITDA (non-GAAP)	**$**	**4,478**(C)
Interest Expense - booked less default Interest	$	3,554
Add: Default Interest and Waiver Fees		2,936
Add: Capitalized Interest		717
Less: Amortized costs		(907)
Add: Cash Preferred Dividends		765
Modified Interest expense (non-GAAP)	**$**	**7,065**(D)
Long Term Debt (GAAP)	**$**	**66,450**(E)
Leverage Ratio (E)/(C)		14.84
Interest Coverage Ratio (C) / (D)		0.63

The amounts included in the calculation of EBITDA and modified interest expense were computed in accordance with GAAP. EBITDA is presented herein and reconciled to the GAAP measure of net income because of its wide acceptance by the investment community as a financial indicator of a company s ability to internally fund development and exploration activities and its use in determining our interest coverage ratio. Modified interest expense is presented herein and reconciled to the GAAP measure of interest expense because of its use in determining our interest coverage ratio. These non-GAAP financial measures are provided in addition to, and not as alternatives for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in this annual report.

The SCA has a minimum asset coverage ratio covenant that requires us to maintain a ratio of not less than 1.50 to 1.00. The minimum asset coverage ratio is calculated by dividing (i) Total Present Value, using oil and gas prices based on NYMEX futures prices as of the applicable determination date, which is defined as the sum of 100% of the net present value, discounted at 10% per annum, of the future net revenues expected to accrue to (A) PDP reserves, (B) PDNP reserves and (C) PUD reserves, with the total present value of PDP reserves being at least 60% of the aggregate total present value, by (ii) consolidated Debt (as defined in the Subordinated Credit Agreement) as of the applicable determination date. At June 30, 2011, our minimum asset coverage ratio was 2.09 to 1.00, calculated as follows:

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		Quarter Ended June 30, 2011
Total present value (non-GAAP)	$	138.8 million

	June 30, 2011
Long-term debt (GAAP)	66.5 million
Total present value to debt (C)/(D)	2.09 to 1.00

Series D Preferred Stock

We were required to redeem our Preferred Stock that remained outstanding on September 6, 2011 for a redemption amount in cash equal to the stated value of the Preferred Stock, plus accrued dividends and PIK dividends. However, the subordination provisions of the Preferred Stock prohibit us from redeeming the Preferred Stock while we are in default under the ARCA. As a result of our defaults under the ARCA and SCA, we were not able to redeem the outstanding Preferred Stock as of its maturity date. Without successfully implementing one of our strategic alternatives or restructuring our existing indebtedness, we do not expect to be able to cure our defaults under the ARCA and SCA any time in the foreseeable future. Accordingly, we do not expect to be able to redeem our outstanding Preferred Stock in the foreseeable future.

Fiscal 2012 Capital Expenditures

As of June 30, 2011, we had no material commitments for capital expenditures. Due to the Company s current financial condition, including continued losses, defaults under our loan agreements and our Series D Preferred Stock, no available borrowing capacity, constrained cash flow, negative working capital, and limited to no access to additional capital, the Company has made no material commitments for capital expenditures and will not make any material commitments for capital expenditures in the foreseeable future.

Results of Operations Years Ended June 30, 2011, 2010, and 2009

Overall

For the 2011 Fiscal Year, we had a loss applicable to common stock of $188.8 million, which was a $175.4 million decrease as compared to the loss applicable to common stock of $13.4 million for the 2010 Fiscal Year. Items contributing to the $175.4 million decrease were impairment of assets of $172.9 million, loss on derivatives of $8.8 million, increased interest expense of $5.4 million, loss on sales of oil and gas properties of $0.8 million and increased preferred stock dividend of $1.3 million. Partially offsetting the earnings decrease were lower lease operating expenses of $3.0 million and increased operating revenues of $3.3 million.

For the 2010 Fiscal Year, we had a loss applicable to common stock of $13.4 million, which was a $21.3 million decrease as compared to income applicable to common stock of $7.9 million for the 2009 Fiscal Year. Items contributing to the $21.3 million decrease were reduced gain on derivatives of $45.7 million, decreased income from preferred stock repurchased for less than the carrying amount of $10.9 million and lower income from discontinued operations of $10.3 million. Partially offsetting the earnings decrease were lower operating expenses of $43.9 million, which is primarily attributable to a $26.7 million charge for impairment of long-lived assets during the 2009 Fiscal Year. Other items that decreased operating expenses were reductions to general and administrative expenses of $7.3 million, decreased exploration expense of $6.4 million and lower lease operating expenses of $2.8 million.

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Operating Revenues

The table below summarizes our operating revenues:

	Years Ended June 30,						Increase (Decrease)		
	2011		2010		2009		2011 v. 2010		2010 v. 2009
Operating Revenues *(In Thousands)*	$	26,127	$	22,849	$	23,433	3,278	$	(584)
Sales:									
Crude Oil (MBbls)		266		285		308	(19)		(23)
Natural Gas (MMcf)		447		426		545	21		(119)
MBOE		340		356		399	(16)		(43)
Average Realized Price									
Crude Oil ($/Bbl)	$	84.14	$	68.98	$	62.13	$ 15.16	$	6.85
Natural Gas ($/Mcf)	$	8.48	$	7.53	$	7.28	$ 0.95	$	0.25

(a) On August 10, 2010, we sold certain natural gas commodity derivative contracts realizing net proceeds of $0.8 million pursuant to the Forbearance Agreement. The $0.8 million is excluded from the commodity derivative settlements listed above.

2011 Fiscal Year v. 2010 Fiscal Year

The 2011 Fiscal Year operating revenues of $26.1 million were $3.3 million higher as compared to the 2010 Fiscal Year operating revenues of $22.8 million. The $3.3 million increase is primarily attributable to higher average prices received for crude oil and natural gas sales of $22.3 million and $3.8 million, respectively, compared to crude oil and natural gas sales of $19.6 million and $3.2 million, respectively for the 2010 fiscal year.

Crude Oil Sales. Our 2011 Fiscal Year crude oil sales were 19.2 MBbls lower as compared to the 2010 Fiscal Year. The overall sales decrease resulted primarily from reduced sales at our Cato Properties of 17.4 MBbls. Partially offsetting the sales decrease were increased combined sales at the Desdemona and Davenport Properties of 6.3 MBbls. The change to the sales of our individual properties is further discussed under the section: *Development Capital Development and Operating Activities Update.*

Natural Gas Sales. Our 2011 Fiscal Year natural gas sales were 21 MMcf higher as compared to the 2010 Fiscal Year. The overall sales increase is attributable to higher sales at our Desdemona Properties of 64 MMcf partially offset by lower sales at the Panhandle Properties of 40 MMcf. The change to the sales of our individual properties is further discussed under the section *Development Capital Development and Operating Activities Update.*

2010 Fiscal Year v. 2009 Fiscal Year

The 2010 Fiscal Year operating revenues of $22.8 million were $0.6 million lower as compared to the 2009 Fiscal Year operating revenues of $23.4 million. The $0.6 million reduction is primarily attributable to decreased crude oil and natural gas sales volumes, which lowered revenues by $1.6 million and $0.9 million, respectively, and lower other revenues of $0.3 million. The decreases were partially offset by increased prices received for crude oil and natural gas sales volumes of $2.1 million and $0.2 million, respectively.

Crude Oil Sales. Our 2010 Fiscal Year crude oil sales were 23 MBbls lower as compared to the 2009 Fiscal Year due to lower sales from our Cato Properties and Panhandle Properties of 12 MBbls and 8 MBbls, respectively. The sales decrease at our Cato Properties resulted from the redistribution of water injection at the waterflood, which resulted in lower production.

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The sales decrease at the Panhandle Properties is due to the controlled injection project at the Cockrell Ranch waterflood and severe weather during January and February 2010, which temporarily curtailed production. All Cockrell Ranch production that had been temporarily shut-in for the controlled injection project was restored on September 28, 2009.

Natural Gas Sales. Our 2010 Fiscal Year natural gas sales were 119 MMcf lower as compared to the 2009 Fiscal Year primarily due to lower sales from the Panhandle Properties of 44 MMcf, Desdemona Properties of 36 MMcf and Cato Properties of 36 MMcf. Lower natural gas sales from the Panhandle Properties resulted from severe weather and from the controlled production project at Cockrell Ranch waterflood, as previously discussed, and one of our gas purchasers experiencing unplanned plant outages during August 2009, September 2009, May 2010 and June 2010, which resulted in reduced natural gas and NGL sales. Lower natural gas sales at the Desdemona Properties resulted from the shut-in natural gas production from our Barnett Shale wells during July 2009, based upon the then current and near-term outlook of natural gas prices, and the temporary shut-in of our gas plant to equip the plant to handle increased natural gas production from the return to production of 25 shut-in Duke Sand gas wells. Lower natural gas sales at the Cato Properties resulted from the purchaser temporarily declining to take natural gas production from January through March 2010.

Crude Oil and Natural Gas Prices

The average price we receive for crude oil sales is generally at market prices received at the wellhead, except for the Cato Properties, for which we receive below market prices due to the lower gravity of the crude oil, sulfur content, and transportation expenses. The average price we receive for natural gas sales is approximately the market price received at the wellhead, adjusted for the value of natural gas liquids, less transportation and marketing expenses. For the current quarter and the 2011 Fiscal Year, our average price received for crude oil sales was $98.09 per barrel and $84.14 per barrel, respectively. For the current quarter and the 2011 Fiscal Year, our average price received for natural gas sales was $8.24 per MCF and $8.48 per MCF, respectively. The natural gas prices include the effect of NGL content that is subsequently removed from the gas stream and sold as a liquid.

The average prices we received for our crude oil and natural gas sales were supplemented by commodity derivative settlements received for the current and prior year quarters. As discussed in Note 6 to our Consolidated Financial Statements, if crude oil and natural gas NYMEX prices were lower than the fixed prices, we would be reimbursed by our counterparty for the difference between the NYMEX price and fixed price (i.e. realized gain). Conversely, if crude oil and natural gas NYMEX prices were higher than the derivative fixed prices, we would pay our counterparty for the difference between the NYMEX price and fixed price (i.e. realized loss). On August 22, 2011, we executed a mutual termination letter with Natixis providing for the termination of two fixed price commodity swap contracts that we entered into on September 11, 2009. In connection with the termination of the commodity swap transactions, we must pay $3.65 million to Natixis.

Operating Expenses

2011 Fiscal Year v. 2010 Fiscal Year

For the 2011 Fiscal Year, our total operating expenses were $214.7 million, or $174.7 million higher than the 2010 Fiscal Year of $40.0 million. This was primarily due to impairment expenses of $172.9 million and depletion expenses of $19.9 million.

2010 Fiscal Year v. 2009 Fiscal Year

For the 2010 Fiscal Year, our total operating expenses were $40.0 million, or $43.9 million lower than the 2009 Fiscal Year of $83.8 million. The 2009 Fiscal Year included an impairment of long-lived assets of $26.7 million, which is the primary reason for the overall decrease. In addition, we had reduced general and administrative of $7.3 million, reduced exploration expense of $6.4 million, lower lease operating expenses of $2.8 million and lower depletion and depreciation expense of $0.8 million.

Lease Operating Expenses

Our lease operating expenses (LOE) consist of the costs of producing crude oil and natural gas such as labor, supplies, repairs, maintenance, workovers and utilities.

For the 2011 Fiscal Year, our LOE was $12.7 million, which was $3.0 million lower than the 2010 Fiscal Year of $15.7 million. The $3.0 million decrease resulted primarily from reduced service rates negotiated with vendors and improved operating efficiencies, which led to a decreased workover expenses total of $2.9 million, lower chemical treatments of $0.7

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million, decreased repairs of $1.0 million, lower labor expenses of $2.1 million and total expense reductions of $3.0 million over the prior year.

For the 2011 Fiscal Year, our LOE, based on production, was $33.49 per BOE, which is a reduction of $5.41 per BOE compared to the 2010 Fiscal Year of $38.90 per BOE.

For the 2010 Fiscal Year, our LOE was $15.7 million, which is $2.8 million lower than 2009 Fiscal Year of $18.5 million. The $2.8 million decrease resulted primarily from reduced service rates negotiated with vendors of $2.5 million, the suspension of our Barnett Shale natural gas wells, which reduced LOE by $0.6 million, and lower electricity expense of $0.3 million. Partially offsetting these LOE cost reductions were increased LOE at the Cato Properties of $0.6 million to support increased focus on production activities.

For the 2010 Fiscal Year, our LOE per BOE, based on production, was reduced by $5.55 per BOE to $38.90 as compared to $44.45 for the 2009 Fiscal Year.

Production and Ad Valorem Taxes

For the 2011 Fiscal Year, our production and ad valorem taxes were $2.1 million, which is $0.2 million higher than the 2010 Fiscal Year of $1.9 million. The increases were due to higher operating revenues, as previously discussed. Our production taxes as a percent of operating revenues for the 2011 Fiscal Year 8.0% and were comparable to the 2010 Fiscal Year of 8.0%.

For the 2010 Fiscal Year, our production and ad valorem taxes were $1.9 million, which is $0.2 million lower than the 2009 Fiscal Year of $2.1 million. Our production taxes were lower by $0.1 million due to lower operating revenues and ad valorem taxes were lower by $0.1 million due to reductions in tax property valuations by taxing authorities. Our production taxes as a percent of operating revenues for the 2010 Fiscal Year of 6.3% was comparable to the 2009 Fiscal Year of 6.5%.

General and Administrative Expenses

Our general and administrative (G&A) expenses consist of support services for our operating activities, legal matters and investor relations costs.

2011 Fiscal Year v. 2010 Fiscal Year

For the 2011 Fiscal Year, our G&A expenses totaled $6.8 million, which was $5.0 million lower than the 2010 Fiscal Year of $11.8 million. The $5.0 million expense reduction resulted primarily from costs savings of $2.3 million related to a 89% reduction in employees at our home office, resulting in lower payroll and benefits costs of $2.2 million, against a total of $4.5 million for 2010, reduced stock-based compensation of $(0.6) million, compared to $1.0 million for the prior year, reduced fees to our board of directors of $0.03 million compared to $0.6 million in 2010 and other costs reductions such as a reduction in accounting costs from $0.8 million in 2010 to $0.5 million for 2011. Partially offsetting the expense reductions were employee severance expenses of $0.5 million, litigation settlements, provisions, and associated legal costs of $0.8 million.

The lower share-based compensation expense resulted from award forfeitures and reduced issuances of stock options and restricted stock. The reduced payroll and benefits costs resulted from significant workforce reductions, which eliminated approximately 77% of our home office staff. During September 2010, we reduced the size of our Board of Directors from six independent directors to two independent directors, which is expected to result in costs savings of approximately $0.4 million annually. During December 2010, we paid $0.3 million for an office lease buyout of our home office lease located in Fort Worth, Texas. During January 2011, we completed our move to our new home office location in Irving, Texas, which is expected to result in cost savings of approximately $0.5 million annually. We are continuing to evaluate and reduce additional G&A expenses.

2010 Fiscal Year v. 2009 Fiscal Year

For the 2010 Fiscal Year, our G&A expenses totaled $11.8 million, which is $7.3 million lower than Fiscal Year 2009 of $19.2 million. The $7.3 million expense reduction resulted primarily from reduced litigation costs of $6.0 million, reduced share-based compensation costs of $2.1 million, and lower payroll and benefits costs of $0.9 million. Partially offsetting these expense reductions were increased costs related to the terminated merger of $2.1 million. The reduced payroll and benefits costs resulted from workforce reductions we implemented during the quarter ended March 31, 2009, which eliminated 25% of our home office staff. The lower share-based compensation costs are directly related to reduced issuances of stock options and restricted stock. The litigation cost reduction occurred as we settled all but one of our fire litigation claims during the fiscal year ended June 30, 2009.

Exploration Expense

During the 2011 Fiscal Year, we had no exploration expense.

During the 2010 Fiscal Year, we recorded exploration expense of $5.0 million pertaining to the Nowata ASP Project. During December 2009, we finalized our performance analysis, which indicated the Nowata ASP Project did not result in significantly increased oil production quantities and is therefore considered not economically viable. Accordingly, at December 31, 2009, we recorded a $5.0 million pre-tax exploration expense.

During the 2009 Fiscal Year, we recorded exploration expense of $11.4 million pertaining to the Duke Sand waterflood project. The primary source of water for this waterflood project had been derived from our Barnett Shale wells. As we shut-in our Barnett Shale natural gas production due to uneconomic natural gas commodity prices, we no longer had an economic source of water to continue flooding the Duke Sand. Therefore, our rate of water injection was reduced to a point where we could not consider the waterflood active.

Impairment of Long-Lived Assets

During the 2011 Fiscal Year, we recorded impairment of $172.9 million related to reductions in estimated PUD and estimated PDNP reserves as a result of the requirements of the SEC s amended Rule 4-10 of Regulation S-X. Among other things, guidance for the Final Rule for the reporting of estimated proved undeveloped reserves requires that a company must have adopted a development plan and have made a final investment decision for their development. The mere intent to develop is not sufficient for reporting estimated proved undeveloped reserves. For all estimated reserves, the Final Rule requires that there must exist, or there must be a reasonable expectation that there will exist, the financing required to implement the development projects. The capital requirement for development of the estimated PUD and PDNP reserves previously reported by the Company as of June 30, 2010, was estimated to be approximately $303.5 million, and approximately $7.0 million, respectively. Due to the Company s current financial constraints, including continued losses, defaults under our loan agreements and our Series D Preferred Stock, no available borrowing capacity, constrained cash flow, negative working capital, and limited to no other capital availability, there is not a reasonable expectation that the Company can obtain the financing required to `implement these projects within a reasonable time, even though we believe these projects, in and of themselves, remain technically feasible and economically attractive. Therefore, we have recorded the aforementioned impairment to our oil and gas properties.

During the 2010 Fiscal Year, we wrote down $0.3 million of costs associated with the ASP facility used for the Nowata ASP Project. The facility s water filtering process did not work properly with the oil-water fluid production at our Nowata Properties. The ASP facility was sold in 2011.

During the 2009 Fiscal Year, we recorded a $26.7 million impairment on our Barnett Shale Properties as the decline in commodity prices created an uncertainty about the likelihood of developing our estimated reserves associated with our Barnett Shale natural gas properties within the next five years. Therefore, during the quarter ended December 31, 2008, we recorded a $22.4 million pre-tax impairment to our Barnett Shale Properties. During the quarter ended June 30, 2009, we recorded an additional $4.3 million pre-tax impairment to our Barnett Shale Properties as the forward outlook for natural gas prices continued to decline and we shut-in our Barnett Shale natural gas wells. The fair value was determined using estimates of future production volumes, prices and operating expenses, discounted to a present value.

Depletion and Depreciation

For the 2011 Fiscal Year, our depletion and depreciation expense was $19.9 million, an increase of $14.9 million when compared to the 2010 Fiscal Year depletion and depreciation expense of $5.0 million. This includes depletion expense pertaining to our oil and natural gas properties, and depreciation expense pertaining to our field operations vehicles and equipment, natural gas plant, office furniture and computers. The increase is due to changes to reserves arising from the 2011 Reserve Report. For the 2011 Fiscal Year, our depletion rate pertaining to our oil and gas properties was $ 55.26 per BOE, as compared to the 2010 Fiscal Year rate of $13.99 per BOE. The increase is due to our reserve redetermination as of June 30, 2011, and the associated impairment of the Company s estimated PUD and estimated PDNP reserves as discussed under *Impairment of Lon-Lived Assets.*

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For the 2010 Fiscal Year, our depletion and depreciation expense was $5.0 million, a decrease of $0.7 million as compared to the 2009 Fiscal Year depletion and depreciation expense. This includes depletion expense pertaining to our oil and natural gas properties, and depreciation expense pertaining to our field operations vehicles and equipment, natural gas plant, office furniture and computers. For the 2010 Fiscal Year, our depletion rate pertaining to our oil and gas properties was $13.99 per BOE, as compared to the 2009 Fiscal Year rate of $14.20 per BOE. The decreased depletion rates resulted primarily from our reserve redetermination at December 31, 2009, and periodic assessments of depletion rates during the 2010 Fiscal Year, and impairments of our Barnett Shale Properties, as previously discussed.

Interest Expense and Other

For the 2011, 2010, and 2009 Fiscal Years, we recorded interest expense of $6.5 million, $1.0 million, and $0.5 million, respectively, as a direct result of our credit agreements. The interest expense for the 2010, and 2009 Fiscal Years was reduced by $2.0 million and $1.4 million, respectively, for interest cost that was capitalized to the waterflood and ASP projects discussed under the *Drilling Capital Development and Operating Activities Update.* We incurred higher interest costs during both the 2011 and 2010 Fiscal Years due to higher outstanding debt balances and higher interest rates as a result of our ongoing defaults under our credit agreements. Interest on the deferred financing increased by $0.5 million from $0.4 million in 2010 to $0.9 million in 2011. Interest waiver fees of $2.9 million were payable, compared to $0 in 2010.

Gain (Loss) on Commodity Derivatives

We had previously entered into financial contracts for our commodity derivatives and our interest rate swap. On August 22, 2011, we executed a mutual termination letter with Natixis providing for the termination of two fixed price commodity swap contracts that we entered into on September 11, 2009. In connection with the termination of the commodity swap transactions, we must pay $3.65 million to Natixis. On September 9, 2011, we executed a mutual termination letter with Natixis providing for the termination of the three-year LIBOR interest rate basis swap contract for $20.0 million in notional exposure that we entered into on January 12, 2009. In connection with the termination of the interest rate swap, we must pay $145,500 to Natixis.

For the 2011 Fiscal Year, the loss on commodity derivatives of $8.8 million consisted of an unrealized loss of $9.3 million and a realized gain of $0.5 million. For the 2010 Fiscal Year, the loss on commodity derivatives of $1.9 million consisted of an unrealized loss of $6.6 million and a realized gain of $4.7 million.

For the realization of settlements pursuant to our prior commodity derivatives financial contracts, if crude oil and natural gas NYMEX prices were lower than the fixed prices, we would be reimbursed by our counterparty for the difference between the NYMEX price and fixed price (i.e. realized gain). Conversely, if crude oil and natural gas NYMEX prices were higher than the fixed prices, we would pay our counterparty for the difference between the NYMEX price and fixed price (i.e. realized loss). By their nature, these commodity derivatives were capable of having a highly volatile impact on our earnings.

Income Tax Benefit (Expense)

Our income tax benefit and effective rates amounted to $18.9 million, or 9.3% for fiscal 2011, $6.5 million, or 32.2% for fiscal 2010, and $5.1 million, or 29.2% for fiscal 2009. The income tax benefit for fiscal 2011 was higher than in 2010 consistent with the decrease in our earnings before taxes, offset by the effect of the change in the valuation allowance on deferred tax assets of $55.6 million. Effective income tax rates differed from the expected statutory rates due primarily to state taxes, non-deductible expenses, and differences in stock-based compensation methods. For 2011, the effective rate was impacted to a greater extent by our establishment of a valuation allowance on deferred tax assets of $55.6 million, based on our continued net losses and our judgment about the Company s ability to generate taxable income in future years.

Loss on Sale of Equipment used in Oil and Gas Operations

During the 2011 Fiscal Year, we sold certain non-essential equipment for $0.8 million, which resulted in a $0.8million loss on the sale of this equipment.

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Income from Discontinued Operations

For the 2011, 2010, and 2009 Fiscal Years, we had income from discontinued operations of $0, $2.1 million, and $12.3 million, respectively, due to our divestitures of the Pantwist, LLC; Corsicana Properties and Certain Panhandle Properties.

Preferred Stock Dividend

The preferred stock dividend for the 2011 Fiscal Year of $3.1 million was $1.3 million higher as compared to the 2010 Fiscal Year of $1.8 million. The increase of $1.3million is attributed to the amortization of issuance costs pertaining to the Preferred Stock. The paid-in-kind and cash dividends are 59% and 41%, respectively.

The preferred stock dividend for the 2010 Fiscal Year of $1.8 million was a decrease of $0.9 million from the 2009 Fiscal Year. This resulted from our repurchase in November and December 2008 of 22,948 shares of Series D Convertible Preferred Stock, including accrued dividends and 2,323 shares from PIK dividends for approximately $10.4 million, realizing a gain of $10.9 million.

On August 5, 2010, we entered into Consent and Forbearance Agreements with the lenders under our credit agreements that prohibited us from making any indirect or direct cash payment, cash dividend or cash distribution in respect of our shares of Series D Convertible Preferred Stock. On September 24, 2010, subsequently updated on January 5, 2011, and September 23, 2011, our lenders delivered Reservation of Rights Letters specifying that we failed to timely comply with the material terms of the Forbearance Agreements and therefore terminated the Forbearance Agreements. During September 2010, we elected to suspend the quarterly dividend paid on the Preferred Stock beginning with the quarter ended September 30, 2010, and continued to suspend the quarterly dividend payment through the 2011 Fiscal Year. Dividends on the Preferred Stock are cumulative. As of June 30, 2011, unpaid cumulative dividends on the Preferred Stock were $0.8 million.

Contractual Obligations

The following table sets forth our contractual obligations in thousands at June 30, 2011, for the periods shown:

Amounts in $000s	**Total**	**Less than 1 Year**	**1 To 3 Years**	**3 to 5 Years**	**More Than 5 Years**
Long-term debt	$ 66,450	$ 66,450			
Series D Preferred Stock	29,213	29,213			
Operating lease obligations	686	135	286	265	
Total contractual obligations	$ 96,349	$ 95,798	$ 286	$ 265	

Off Balance Sheet Arrangements

Our off balance sheet arrangements are limited to operating leases that have not and are not reasonably likely to have a current or future material effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Selected Quarterly Financial Data (Unaudited)

We derived the selected historical financial data in the table below from our unaudited interim consolidated financial statements. The sum of net income per share by quarter may not equal the net income per share for the year due to variations in the weighted average shares outstanding used in computing such amounts. The historical data presented here are only a summary and should be read in conjunction with the consolidated financial statements, related notes and other financial information included elsewhere in this annual report.

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Fiscal Year Ended June 30, 2011 (Unaudited)

In thousands, except per share data	Sept. 30	Dec. 31	Mar. 31	Jun. 30 (b)
Operating revenues from continuing operations	$ 6,244	$ 5,679	$ 6,669	$ 7,535
Operating loss from continuing operations	(1,520)	(982)	1,073	(187,159)
Income (loss) from continuing operations	(4,568)	(3,639)	(4,326)	(173,168)
Income (loss) from discontinued operations, net of tax				
Net income (loss) applicable to common stock	(5,038)	(4,535)	(5,213)	(174,060)
Net income (loss) per share basic and diluted	(0.11)	(0.10)	(0.11)	(3.84)

Fiscal Year Ended June 30, 2010 (Unaudited)

	Sept. 30	Dec. 31(a)	Mar. 31	Jun. 30
Operating revenues from continuing operations	$ 4,931	$ 5,634	$ 5,803	$ 6,481
Operating loss from continuing operations	(4,725)	(8,171)	(2,383)	(7,838)
Income (loss) from continuing operations	(3,683)	(8,640)	(1,494)	(6,241)
Income (loss) from discontinued operations, net of tax	122	206	1,722	7
Net loss applicable to common stock	(4,031)	(8,854)	(242)	(241)
Net loss per share basic and diluted	(0.09)	(0.19)		(0.01)

(a) For the quarter ended December 31, 2009, our results of operations were unfavorably impacted by unrealized loss on commodity derivatives of $5.8 million.

(b) For the quarter ended June 30, 2011, our results of operations were unfavorably impacted by impairment of our oil and gas properties.

Critical Accounting Policies

We have identified the critical accounting policies used in the preparation of our financial statements. These are the accounting policies that we have determined involve the most complex or subjective decisions or assessments.

Consolidation and Use of Estimates

The accompanying financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) and include the accounts of Cano and its wholly-owned subsidiaries. Intercompany accounts and transactions are eliminated. In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies. Actual results may differ from those estimates. Significant assumptions are required in the valuation of estimated proved crude oil and natural gas reserves, which may affect the amount at which crude oil and natural gas properties are recorded. The computation of share-based compensation expense requires assumptions such as volatility, expected life and the risk-free interest rate. Our liabilities and assets associated with commodity derivatives involve significant assumptions related to volatility and future prices for crude oil and natural gas. It is at least reasonably possible these estimates could be revised in the near term, and these revisions could be material.

Cano s Proved Reserves

The term proved reserves is defined by the SEC in Rule 4-10(a) of Regulation S-X adopted under the Securities Act of 1933, as amended. In general, proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods, and government regulations. Prices are based on an unweighted arithmetic average of the first-day-of-the-month price for each month within Fiscal Year 2011, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

A decline in estimates of proved reserves may result from lower prices, new information obtained from development drilling and production history, field tests, data analysis, changes in economic factors including expectation and assumptions as to availability of financing for development projects, mechanical problems on our wells; and catastrophic events such as explosions, hurricanes and floods. Lower prices may make it uneconomical to drill wells or produce from fields having high operating costs.

Our estimates of proved reserves materially affect depletion expense. If estimated proved reserves decline, then the rate at which we record depletion expense increases. In addition, a decline in estimated proved reserves may influence our assessment of our oil and natural gas properties for impairment.

Our proved reserves estimates are a function of many assumptions, all of which could deviate materially from actual results. As such, reserves estimates may vary materially from the ultimate quantities of crude oil and natural gas actually produced.

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Oil and Gas Properties and Equipment

We follow the successful efforts method of accounting. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense. The costs of drilling and equipping exploratory wells are deferred until the Company has determined whether proved reserves have been found. If proved reserves are found, the deferred costs are capitalized as part of the wells and related equipment and facilities. If no proved reserves are found, the deferred costs are charged to expense. All development activity costs are capitalized. We are primarily engaged in the development and acquisition of crude oil and natural gas properties. Our activities are considered development where existing proved reserves are identified prior to commencement of the project and are considered exploration if there are no proved reserves at the beginning of such project. The property costs reflected in the accompanying consolidated balance sheets resulted from acquisition and development activities and deferred exploratory drilling costs. Capitalized overhead costs that directly relate to our drilling and development activities were nil and $0.8 million for the years ended June 30, 2011, and 2010, respectively. We recorded capitalized interest costs of $0.7 million and $2.0 million for the years ended June 30, 2011, and 2010, respectively.

Costs for repairs and maintenance to sustain or increase production from existing producing reservoirs are charged to expense. Significant tangible equipment added or replaced that extends the useful or productive life of the property is capitalized. Costs to construct facilities or increase the productive capacity from existing reservoirs are capitalized.

Depreciation and depletion of producing properties are computed on the unit-of-production method based on estimated proved oil and natural gas reserves. Our unit-of-production amortization rates are revised prospectively on a quarterly basis based on updated engineering information for our estimated proved developed reserves. Our development costs and lease and wellhead equipment are depleted based on estimated proved developed reserves. Our leasehold costs are depleted based on total estimated proved reserves. Investments in major development projects are not depleted until such project is substantially complete and producing or until impairment occurs.

If conditions indicate that long-term assets may be impaired, the carrying value of our properties is compared to management s future estimated undiscounted net cash flow from the properties. If undiscounted cash flows are less than the carrying value, then the asset value is written down to fair value. Impairment of individually significant unproved properties is assessed on a property-by-property basis, and impairment of other unproved properties is assessed and amortized on an aggregate basis. The impairment assessment is affected by factors such as the results of exploration and development activities, commodity price projections, remaining lease terms, and potential shifts in our business strategy.

Asset Retirement Obligation

Our financial statements reflect the fair value of our asset retirement obligation (ARO), which consists of future plugging and abandonment expenditures related to our oil and gas properties, that can be reasonably estimated, and discounted at our credit-adjusted risk-free rate. The asset retirement obligation is recorded as a liability at its estimated fair value at the asset s inception, with an offsetting increase to producing properties on the consolidated balance sheets, which is depreciated such that the cost of the ARO is recognized over the useful life of the asset. Periodic accretion of the discount of the estimated liability to its expected settlement value is recorded as an expense in the consolidated statements of operations.

Inherent in the fair value calculation of ARO are numerous assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance.

Revenue Recognition

Our revenue recognition is based on the sales method. We do not have imbalances for natural gas sales since we are primarily the 100% working interest owner in our properties. We recognize revenue when crude oil and natural gas quantities are delivered to or collected by the respective purchaser. Title to the produced quantities transfers to the purchaser at the time the purchaser receives or collects the quantities. Prices for such production are defined in sales contracts and are readily determinable based on publicly available information. The purchasers of such production have historically made payment for crude oil and natural gas purchases within thirty-five days of the end of each production month. We periodically

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review the difference between the dates of production and the dates we collect payment for such production to ensure that accounts receivable from the purchasers are collectible. The point of sale for our crude oil and natural gas production is at our applicable field tank batteries and gathering systems; therefore, we do not directly incur transportation costs related to our sales of crude oil and natural gas production.

As previously discussed, for the years ended June 30, 2011, 2010, and 2009, we sold our crude oil and natural gas production to several independent purchasers. The following table shows purchasers that accounted for 10% or more of our total operating revenues:

	Year Ended June 30,		
	2011	**2010**	**2009**
Valero Marketing Supply Co.	34%	33%	32%
Coffeyville Resources Refinery and Marketing, LLC	24%	22%	18%
Sunoco, Inc.	11%	*	*
Plains Marketing, LP	*	18%	15%
Eagle Rock Field Services, LP	*	*	13%
DCP Midstream, LP	*	10%	10%

* Less than 10% of operating revenue

Share-Based Compensation Expense

We account for share-based payment arrangements with employees and directors at their grant-date fair value and record the related expense over their respective service periods. The value of share-based compensation is impacted by our stock price, which has been highly volatile, and items that require management s judgment, such as expected lives and forfeiture rates.

Derivatives

We have historically maintained commodity derivative contracts for a portion of our crude oil and natural gas production. The purpose of the derivatives is to reduce our exposure to declining commodity prices. These derivatives are recorded as derivative assets and liabilities on our consolidated balance sheets based upon their respective fair values. We have also historically entered into interest rate basis swap contracts to reduce our exposure to future interest rate increases.

Currently, we are not a party to any derivative contracts. On August 22, 2011, we executed a mutual termination letter with Natixis providing for the termination of two fixed price commodity swap contracts that we entered into on September 11, 2009. In connection with the termination of the commodity swap transactions, we must pay $3.65 million to Natixis. On September 9, 2011, we executed a mutual termination letter with Natixis providing for the termination of the three-year LIBOR interest rate basis swap contract for $20.0 million in notional exposure that we entered into on January 12, 2009. In connection with the termination of the interest rate swap, we must pay $145,500 to Natixis.

We do not designate our derivatives as cash flow or fair value hedges. We do not hold or issue derivatives for speculative or trading purposes. We are exposed to credit losses in the event of nonperformance by the counterparties to our commodity and interest rate swap derivatives. We anticipate, however, that our counterparties will be able to fully satisfy their respective obligations under our commodity and interest rate swap derivatives contracts. We do not obtain collateral or other security to support our commodity derivatives contracts nor are we required to post any collateral. We monitor the credit standing of our counterparties to understand our credit risk.

Changes in the fair values of our derivative instruments and cash flows resulting from the settlement of our derivative instruments are recorded in earnings as gains or losses on derivatives on our consolidated statements of operations.

New Accounting Pronouncements

In January 2010, the FASB issued ASU 2010-06, *Fair Value Measurements and Disclosures (Topic 820)*. ASU 2010-06 Subtopic 820-10 provides new guidance on improving disclosures about fair value measurements. The new standard requires some new disclosures and clarifies some existing disclosure requirements about fair value measurement. Specifically, the new standard will now require: (a) a reporting entity should disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reasons for transfers and (b) in the

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reconciliation for fair value measurements using significant unoberservable inputs, a reporting entity should present separately information about purchases, sales, issuances, and settlements. In addition, the new standard clarifies the requirements of the following existing disclosures: (a) for purposes of reporting fair value measurements for each class of assets and liabilities, a reporting entity needs to use judgment in determining the appropriate classes of assets and liabilities and (b) a reporting entity should provide disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements. The new standard is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. Early application is permitted. The adoption of the requirements of this standard in the quarter ended March 31, 2010, did not have a material impact on our financial position or results of operations.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Not applicable.

Item 8. Financial Statements and Supplementary Data.

The Report of Independent Registered Public Accounting Firm and Consolidated Financial Statements are set forth beginning on page F-1 of this annual report on Form 10-K and are incorporated herein by reference.

The financial statement schedules have been omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or the Notes to our Consolidated Financial Statements.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) that are designed to ensure that information required to be disclosed by us in the reports filed or submitted under the Securities Exchange Act of 1934 is (i) accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure; and (ii) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC.

We carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this annual report. Based on that evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures as of June 30, 2011, were not effective, because of the material weaknesses described in Management s Annual Report on Internal Control over Financial Reporting below.

Management s Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as that term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with GAAP. Our control environment is the foundation for our system of internal control over financial reporting and is an integral part of our Code of Ethics and Business Conduct for Officers, Directors and Employees, which sets the tone of our Company. Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail accurately and fairly reflect our acquisitions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of our financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

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In order to evaluate the effectiveness of our internal control over financial reporting as of June 30, 2011, as required by Section 404 of the Sarbanes-Oxley Act of 2002, our management conducted an assessment, including testing, based on the criteria set forth in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. In addition, 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. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting and, based on that assessment, determined that our internal control over financial reporting was not effective as of June 30, 2011, 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, because of the material weaknesses described below.

A material weakness is a significant deficiency, or combination of significant deficiencies, that results in there being a more than remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. Our independent registered public accounting firm advised our audit committee that the following material weaknesses in internal control existed as of June 30, 2011:

- Our review of our valuation of commodity derivatives did not detect errors in the unrealized loss on commodity derivatives that resulted in a material audit adjustment to our financial statements.

- Our review of certain other computations did not detect errors in such calculations that resulted in adjustments to our financial statements that were less than material, but important enough to merit attention by those responsible for our financial reporting oversight. The aggregate effect of this deficiency when combined with the material weakness described above constitutes a material weakness in internal control over financial reporting.

- We were unable to complete our internal control procedures over financial reporting in a sufficient amount of time to allow us to include our consolidated financial statements in this Annual Report and file it within the time periods specified in the rules and forms of the SEC.

In our judgment, the material weaknesses listed above resulted from significant turnover of our accounting and finance personnel that left us with new accounting and finance personnel who lacked familiarity with our accounting systems, methods and policies. Management is committed to improving our internal control over financial reporting and will (i) continue to use third party specialists to address shortfalls in staffing and to assist the company with accounting and finance responsibilities, (ii) increase our accounting and finance personnel to include a greater number of senior accountants and (iii) further train our current accounting and finance personnel with respect to our accounting systems, methods and policies.

Changes in Internal Controls over Financial Reporting

During the quarter ended June 30, 2011, and during the period subsequent to June 30, 2011 while we were preparing our consolidated financial statements to be included in this Annual Report, substantially all of our accounting and finance personnel resigned. We did not replace all of the personnel who left, and accordingly, certain of our internal control procedures were either reallocated to other personnel or were performed by new employees who lacked familiarity with our accounting systems, methods and policies. This change in personnel has materially affected our internal control over financial reporting. We are committed to improving our internal control over financial reporting and will (i) continue to use third party specialists to address shortfalls in staffing and to assist the company with accounting and finance responsibilities, (ii) increase our accounting and finance personnel to include a greater number of senior accountants and (iii) further train our current accounting and finance personnel with respect to our accounting systems, methods and policies.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Information required by this item relating to our (i) directors and executive officers, (ii) audit committee, (iii) Code of Ethics and Business Conduct, (iv) changes in procedures by which security holders may recommend nominees to our board of directors, and (v) compliance with Section 16(a) of the Securities Exchange Act will be set forth in the earlier filed of an amendment to this annual report on Form 10-K or our definitive proxy statement relating to our 2011 annual meeting of stockholders and will be incorporated herein by reference.

Item 11. Executive Compensation.

Information required by this item relating to executive compensation will be set forth in the earlier filed of an amendment to this annual report on Form 10-K or our definitive proxy statement relating to the 2011 annual meeting of stockholders and will be incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Information required by this item relating to (i) security ownership of certain beneficial owners and management and (ii) securities authorized for issuance under equity compensation plans will be set forth in the earlier filed of an amendment to this annual report on Form 10-K or our definitive proxy statement relating to the 2011 annual meeting of

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stockholders and will be incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

Information required by this item relating to (i) certain business relationships and related transactions with management and other related parties and (ii) director independence will be set forth in the earlier filed of an amendment to this annual report on Form 10-K or our definitive proxy statement relating to the 2011 annual meeting of stockholders and will be incorporated herein by reference.

Item 14. Principal Accounting Fees and Services.

The information relating to (i) fees billed to the Company by the independent registered public accounting firm for services for the years ended June 30, 2011 and 2010 and (ii) the audit committee s pre-approval policies and procedures for audit and non-audit services, will be set forth in the earlier filed of an amendment to this annual report on Form 10-K or our definitive proxy statement relating to our 2011 annual meeting of stockholders and will be incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) The following documents are filed as part of this report:

1. Index to Consolidated Financial Statements, Report of Independent Registered Public Accounting Firm, Consolidated Balance Sheets as of June 30, 2011, and 2010, Consolidated Statements of Operations for each of the three years in the period ended June 30, 2011, Consolidated Statements of Changes in Stockholders Equity for each of the three years in the period ended June 30, 2011, Consolidated Statements of Cash Flows for each of the three years in the period ended June 30, 2011, and Notes to Consolidated Financial Statements.

2. The financial statement schedules have been omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or the Notes to Consolidated Financial Statements.

3. The exhibits required to be filed by this Item 15 are set forth in the Index to Exhibits accompanying this report.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	CANO PETROLEUM, INC.	
Date: October 20, 2011	By:	/s/ JAMES R. LATIMER III James R. Latimer III *Chief Executive Officer*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date: October 20, 2011	By:	/s/ JOHN H. HOMIER John H. Homier *Chief Financial Officer and Secretary*

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned directors of Cano Petroleum, Inc. hereby constitutes and appoints James R. Latimer III and John H. Homier or either of them (with full power to each of them to act alone), his true and lawful attorneys-in-fact and agents, with full power of substitution, for him and on his behalf and in his name, place and stead, in any and all capacities, to sign, execute and file any and all amendments to this Form 10-K, with all exhibits thereto, and other documents in connection therewith, with the SEC, granting unto said attorneys, and each of them, full power and authority to do so and perform each and every act and thing requisite and necessary to be done in and about the premises in order to effectuate the same as full to all intents and purposes as he himself might or could do if personally present, thereby ratifying and confirming all that said attorneys-in-fact and agents, or either of them, or their or his substitute or substitutes, may lawfully do or cause to be done.

In accordance with the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/S/ S. DONALD W. NIEMIEC Donald W. Niemiec	Chairman of the Board	October 20, 2011
/s/ GARRETT SMITH Garrett Smith	Director	October 20, 2011

/s/ JAMES R. LATIMER III James R. Latimer III	Director	October 20, 2011

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INDEX TO EXHIBITS

Exhibit Number	Description
3.1	Certificate of Incorporation of Huron Ventures, Inc., incorporated herein by reference to Exhibit 3.1 to the Company s Registration Statement on Form 10 SB (File No. 000-50386) filed with the SEC on September 4, 2003.
3.2	Certificate of Ownership of Huron Ventures, Inc. and Cano Petroleum, Inc., amending the Company s Certificate of Incorporation, incorporated herein by reference to Exhibit 3.2 to the Company s Annual Report on Form 10-KSB filed with the SEC on September 23, 2004.
3.3	Certificate of Amendment to Certificate of Incorporation of Cano Petroleum, Inc., incorporated herein by reference to Exhibit 3.8 to the Company s Post-Effective Amendment No. 2 on Form S-1 filed with the SEC on January 23, 2007.
3.4	Second Amended and Restated By-Laws of Cano Petroleum, Inc. dated May 7, 2009, incorporated herein by reference to Exhibit 3.1 to the Company s Current Report on Form 8-K filed with the SEC on May 13, 2009.
3.5	Certificate of Designation for Series B Convertible Preferred Stock, incorporated herein by reference to Exhibit 99.2 to the Company s Current Report on Form 8-K filed with the SEC on June 8, 2004.
3.6	Certificate of Designation for Series C Convertible Preferred Stock, incorporated herein by reference to Exhibit 99.2 to the Company s Current Report on Form 8-K filed with the SEC on July 15, 2004.
3.7	Certificate of Designation for Series D Convertible Preferred Stock, incorporated herein by reference to Exhibit 3.1 to the Company s Current Report on Form 8-K filed with the SEC on September 7, 2006.
3.8	Certificate of Amendment to Certificate of Designations, Preferences and Rights of Series D Convertible Preferred Stock of the Company, incorporated herein by reference to Exhibit 3.1 to the Company s Current Report on Form 8-K filed with the SEC on June 24, 2010.
4.3	Form of Common Stock certificate, incorporated herein by reference to Exhibit 4.9 to the Company s Registration Statement on Form S-3 (No. 333-148053) filed with the SEC on December 13, 2007.
4.4	Designation for Series A Convertible Preferred Stock, included in the Certificate of Incorporation of Huron Ventures, Inc., incorporated herein by reference to Exhibit 3.1 to the Company s registration statement on Form 10 SB (File No. 000-50386) filed with the SEC on September 4, 2003.
4.5	Certificate of Designation for Series B Convertible Preferred Stock, incorporated herein by reference to Exhibit 99.2 to the Company s Current Report on Form 8-K filed with the SEC on June 8, 2004.
4.6	Certificate of Designation for Series C Convertible Preferred Stock, incorporated herein by reference to Exhibit 99.2 to the Company s Current Report on Form 8-K filed with the SEC on July 15, 2004.
4.7	Certificate of Designation for Series D Convertible Preferred Stock incorporated herein by reference to Exhibit 3.1 to the Company s Current Report on Form 8-K filed with the SEC on September 7, 2006.
4.8	Certificate of Amendment to Certificate of Designations, Preferences and Rights of Series D Convertible Preferred Stock of the Company, incorporated herein by reference to Exhibit 3.1 to the Company s Current Report on Form 8-K filed with the SEC on June 24, 2010.
10.1+	Stock Option Agreement dated December 16, 2004 between Cano Petroleum, Inc. and Gerald W. Haddock, incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on December 16, 2004.
10.2+	2005 Directors Stock Option Plan, incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on June 28, 2005.
10.3+	Cano Petroleum, Inc. 2005 Long-Term Incentive Plan dated December 7, 2005, incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on December 9, 2005.
10.4+	Form of Non-Qualified Stock Option Agreement under the Cano Petroleum, Inc. 2005 Long-Term Incentive Plan, incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on December 19, 2005.
10.5+	Employment Agreement dated effective January 1, 2006 between Cano Petroleum, Inc. and S. Jeffrey Johnson, incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on January 19, 2006.
10.7+	Employment Agreement of Patrick M. McKinney effective June 1, 2006, incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on November 9, 2006.
10.8+	First Amendment to Employment Agreement of Patrick M. McKinney dated November 9, 2006, incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed with the SEC on November 9, 2006.
10.10+	Employment Agreement of Michael J. Ricketts effective July 1, 2006, incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on August 17, 2006.

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10.13+	Amendment No. 1 to the Cano Petroleum, Inc. 2005 Long-Term Incentive Plan dated December 28, 2006, incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on January 4, 2007.
10.14+	Nonqualified Stock Option Agreement dated December 28, 2006 between Cano Petroleum, Inc. and S. Jeffrey Johnson, incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed with the SEC on January 4, 2007.
10.18+	Nonqualified Stock Option Agreement dated December 28, 2006 between Cano Petroleum, Inc. and Michael J. Ricketts, incorporated herein by reference to Exhibit 10.6 to the Company s Current Report on Form 8-K filed with the SEC on January 4, 2007.
10.21+	Nonqualified Stock Option Agreement of Randall C. Boyd dated December 28, 2006, incorporated herein by reference to Exhibit 10.77 to the Company s Post-Effective Amendment No. 2 on Form S-1 (File No. 333-126167) filed with the SEC on January 23, 2007.
10.25+	Nonqualified Stock Option Agreement of William O. Powell III dated April 4, 2007, incorporated herein by reference to Exhibit 10.7 to the Company s Quarterly Report on Form 10-Q filed with the SEC on May 9, 2007.
10.26+	Nonqualified Stock Option Agreement of Robert L. Gaudin dated April 4, 2007, incorporated herein by reference to Exhibit 10.8 to the Company s Quarterly Report on Form 10-Q filed with the SEC on May 9, 2007.
10.27+	Nonqualified Stock Option Agreement of Donald W. Niemiec dated April 4, 2007, incorporated herein by reference to Exhibit 10.9 to the Company s Quarterly Report on Form 10-Q filed with the SEC on May 9, 2007.
10.30+	Form of Restricted Stock Award under the Cano Petroleum, Inc. 2005 Long-Term Incentive Plan, incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on July 2, 2007.
10.31+	Form of Nonqualified Stock Option Agreement under the Cano Petroleum, Inc. 2005 Long-Term Incentive Plan, incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed with the SEC on July 2, 2007.
10.32+	Second Amendment to Employment Agreement of Patrick M. McKinney dated June 29, 2007, incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed with the SEC on July 3, 2007.
10.33+	First Amendment to Employment Agreement of Michael J. Ricketts dated June 29, 2007, incorporated herein by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K filed with the SEC on July 3, 2007.
10.34+	Form of the First Amendment to the Cano Petroleum, Inc. Employee Restricted Stock Award Agreement, incorporated herein by reference to Exhibit 10.96 to the Company s Annual Report on Form 10-K filed with the SEC on September 11, 2007.
10.35+	Form of Restricted Stock Award under the Cano Petroleum, Inc. 2005 Long-Term Incentive Plan, incorporated herein by reference to Exhibit 10.97 to the Company s Annual Report on Form 10-K filed with the SEC on September 11, 2007.
10.38+	First Amendment dated June 28, 2007 to the Cano Petroleum, Inc. Nonqualified Stock Option Agreement of James Dale Underwood dated December 13, 2005 incorporated herein by reference to Exhibit 10.103 to the Company s Annual Report on Form 10-K filed with the SEC on September 11, 2007.
10.39+	First Amendment dated June 28, 2007 to the Cano Petroleum, Inc. Nonqualified Stock Option Agreement of James Underwood dated December 28, 2006, incorporated herein by reference to Exhibit 10.104 to the Company s Annual Report on Form 10-K filed with the SEC on September 11, 2007.
10.51	$25,000,000 Subordinated Credit Agreement dated March 17, 2008 between Cano Petroleum, Inc. as Borrower, the Lenders Party Hereto from Time to Time as Lenders, and UnionBanCal Equities, Inc. as Administrative Agent, incorporated herein by reference to Exhibit 10.6 to the Company s Quarterly Report on Form 10-Q filed with the SEC on May 8, 2008.
10.52	Subordinated Security Agreement dated March 17, 2008 among Cano Petroleum, Inc., Ladder Companies, Inc., Square One Energy, Inc., WO Energy, Inc., W.O. Energy of Nevada, Inc., Cano Petro of New Mexico, Inc., Pantwist, LLC, W.O. Operating Company, Ltd., W.O. Production Company, Ltd., and UnionBanCal Equities, Inc. as Administrative Agent, incorporated herein by reference to Exhibit 10.7 to the Company s Quarterly Report on Form 10-Q filed with the SEC on May 8, 2008.
10.53	Subordinated Pledge Agreement dated March 17, 2008 among Cano Petroleum, Inc., WO Energy, Inc., W.O. Energy of Nevada, Inc. and UnionBanCal Equities, Inc. as Administrative Agent, incorporated herein by reference to Exhibit 10.8 to the Company s Quarterly Report on Form 10-Q filed with the SEC on May 8, 2008.

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10.54	Subordinated Guaranty Agreement dated March 17, 2008 by Ladder Companies, Inc., Square One Energy, Inc., WO Energy, Inc., W.O. Energy of Nevada, Inc., Cano Petro of New Mexico, Inc., Pantwist, LLC, W.O. Operating Company, Ltd., and W.O. Production Company, Ltd., in favor of UnionBanCal Equities, Inc. as Administrative Agent, incorporated herein by reference to Exhibit 10.9 to the Company s Quarterly Report on Form 10-Q filed with the SEC on May 8, 2008.
10.55	Consent Agreement dated February 21, 2008 among Cano Petroleum, Inc., Ladder Companies, Inc., Square One Energy, Inc., WO Energy, Inc., W.O. Energy of Nevada, Inc., Cano Petro of New Mexico, Inc., Pantwist, LLC, W.O. Operating Company, Ltd., W.O. Production Company, Ltd., Union Bank of California, N.A. and Natixis, incorporated herein by reference to Exhibit 10.11 to the Company s Quarterly Report on Form 10-Q filed with the SEC on May 8, 2008.
10.56+	First Amendment dated May 31, 2008 to Employment Agreement of S. Jeffrey Johnson dated January 1, 2006, incorporated herein by reference to Exhibit 10.84 to the Company s Annual Report on Form 10-K filed with the SEC on September 11, 2008.
10.57+	Third Amendment dated May 31, 2008 to Employment Agreement of Patrick M. McKinney dated June 29, 2007, as amended, incorporated herein by reference to Exhibit 10.86 to the Company s Annual Report on Form 10-K filed with the SEC on September 11, 2008.
10.58+	Fourth Amendment dated May 31, 2008 to Employment Agreement of Michael J. Ricketts dated May 28, 2004, as amended, incorporated herein by reference to Exhibit 10.87 to the Company s Annual Report on Form 10-K filed with the SEC on September 11, 2008.
10.59+	Employment Agreement of Phillip Feiner dated May 31, 2008, incorporated herein by reference to Exhibit 10.88 to the Company s Annual Report on Form 10-K filed with the SEC on September 11, 2008.
10.60+	Employment Agreement of Benjamin Daitch dated June 23, 2008, incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on June 24, 2008.
10.61+	Restricted Stock Agreement of Benjamin Daitch dated June 23, 2008, incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed with the SEC on June 24, 2008.
10.62	Consent and Amendment No. 1 dated June 27, 2008 among Cano Petroleum, Inc., Ladder Companies, Inc., Square One Energy, Inc., WO Energy, Inc., W.O. Energy of Nevada, Inc., Cano Petro of New Mexico, Inc., Pantwist, LLC, W.O. Operating Company, Ltd., W.O. Production Company, Ltd., and UnionBanCal Equities, Inc. as Administrative Agent, incorporated herein by reference to Exhibit 10.94 to the Company s Annual Report on Form 10-K filed with the SEC on September 11, 2008.
10.63	Amendment No. 2 dated effective June 30, 2008 among Cano Petroleum, Inc., Ladder Companies, Inc., Square One Energy, Inc., WO Energy, Inc., W.O. Energy of Nevada, Inc., Cano Petro of New Mexico, Inc., Pantwist, LLC, W.O. Operating Company, Ltd., W.O. Production Company, Ltd., and UnionBanCal Equities, Inc. as Administrative Agent, incorporated herein by reference to Exhibit 10.95 to the Company s Annual Report on Form 10-K filed with the SEC on September 11, 2008.
10.65	Amendment 11 to Valero # 01-0838 dated June 12, 2006 between W.O. Operating Company, Ltd. and Valero Marketing and Supply Company (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.97 to Amendment No. 2 to the Company s Annual Report on Form 10-K/A filed with the SEC on July 6, 2009.
10.66	Amendment 12 to Valero # 01-0838 dated August 23, 2006 between W.O. Operating Company, Ltd. and Valero Marketing and Supply Company, incorporated herein by reference to Exhibit 10.98 to Amendment No. 2 to the Company s Annual Report on Form 10-K/A filed with the SEC on July 6, 2009.
10.67	Amendment 13 to Valero # 01-0838 dated August 31, 2007 between W.O. Operating Company, Ltd. and Valero Marketing and Supply Company (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.99 to Amendment No. 2 to the Company s Annual Report on Form 10-K/A filed with the SEC on July 6, 2009.
10.68	Amendment 14 to Valero # 01-0838 dated January 25, 2008 between W.O. Operating Company, Ltd. and Valero Marketing and Supply Company (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.100 to Amendment No. 2 to the Company s Annual Report on Form 10-K/A filed with the SEC on July 6, 2009.
10.69	Amendment 15 to Valero # 01-0838 dated August 1, 2008 between W.O. Operating Company, Ltd. and Valero Marketing and Supply Company (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.101 to Amendment No. 2 to the Company s Annual Report on Form 10-K/A filed with the SEC on July 6, 2009.
10.70	Amendment 16 to Valero # 01-0838 dated April 3, 2009, between W.O. Operating Company, Ltd. and Valero Marketing and Supply Company, incorporated herein by reference to Exhibit 10.102 to Amendment No. 2 to the Company s Annual Report on Form 10-K/A filed with the SEC on July 6, 2009.

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10.71	Amendment 17 to Valero # 01-0838 dated May 1, 2009, between W.O. Operating Company, Ltd. and Valero Marketing and Supply Company (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.103 to Amendment No. 2 to the Company s Annual Report on Form 10-K/A filed with the SEC on July 6, 2009.
10.72	Gas Purchase Agreement dated April 1, 2007 between Eagle Rock Field Services, L.P. and W.O. Operating Company, Ltd. and Pantwist, LLC (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.104 to Amendment No. 2 to the Company s Annual Report on Form 10-K/A filed with the SEC on July 6, 2009.
10.73	Letter Agreement dated March 25, 2009, Regarding Gas Purchase Agreement dated April 1, 2007 Eagle Rock Contract (#50038 Schafer) between Eagle Rock Energy Partners and W.O. Operating Company, Ltd. (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.105 to Amendment No. 2 to the Company s Annual Report on Form 10-K/A filed with the SEC on July 6, 2009.
10.74	Letter Agreement dated April 30, 2009, Regarding Gas Purchase Agreement dated April 1, 2007 Eagle Rock Contract (#50038 Schafer) between Eagle Rock Energy Partners and W.O. Operating Company, Ltd., incorporated herein by reference to Exhibit 10.106 to Amendment No. 2 to the Company s Annual Report on Form 10-K/A filed with the SEC on July 6, 2009
10.76	Letter Agreement Regarding Crude Oil Purchase Agreement for Ladder Energy Operated Leases, dated January 15, 2009, between Ladder Energy Companies, Inc. and Coffeyville Resources Refinery and Marketing, LLC (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.108 to Amendment No. 2 to the Company s Annual Report on Form 10-K/A filed with the SEC on July 6, 2009.
10.77	Letter Agreement Regarding Crude Oil Purchase Agreement for Ladder Energy Operated Leases, dated February 11, 2009, between Ladder Energy Companies, Inc. and Coffeyville Resources Refinery and Marketing, LLC (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.109 to Amendment No. 2 to the Company s Annual Report on Form 10 K/A filed with the SEC on July 6, 2009.
10.78	Letter Regarding Gas Purchase Contract No. PAM058500*, Panhandle Area, dated May 21, 2009, between W.O. Operating Company, Ltd. and DCP Midstream, incorporated herein by reference to Exhibit 10.113 to Amendment No. 2 to the Company s Annual Report on Form 10 K/A filed with the SEC on July 6, 2009.
10.79	Letter Regarding Gas Purchase Contract No. BOR066300A, Panhandle Area, dated May 21, 2009, between W.O. Operating Company, Ltd. and DCP Midstream, incorporated herein by reference to Exhibit 10.114 to Amendment No. 2 to the Company s Annual Report on Form 10 K/A filed with the SEC on July 6, 2009.
10.80	Letter Regarding Gas Purchase Contract No. BOR067500B, Panhandle Area, dated May 21, 2009, between W.O. Operating Company, Ltd. and DCP Midstream, incorporated herein by reference to Exhibit 10.115 to Amendment No. 2 to the Company s Annual Report on Form 10 K/A filed with the SEC on July 6, 2009.
10.81	Letter Regarding Gas Purchase Contract No. BOR118000R, Panhandle Area, dated May 21, 2009, between W.O. Operating Company, Ltd. and DCP Midstream, incorporated herein by reference to Exhibit 10.116 to Amendment No. 2 to the Company s Annual Report on Form 10 K/A filed with the SEC on July 6, 2009.
10.82	Letter Regarding Gas Purchase Contract No. BOR118100*, Panhandle Area, dated May 21, 2009, between W.O. Operating Company, Ltd. and DCP Midstream, incorporated herein by reference to Exhibit 10.117 to Amendment No. 2 to the Company s Annual Report on Form 10 K/A filed with the SEC on July 6, 2009.
10.83	Letter Regarding Gas Purchase Contract No. BOR134200R, Panhandle Area, dated May 21, 2009, between W.O. Operating Company, Ltd. and DCP Midstream, incorporated herein by reference to Exhibit 10.118 to Amendment No. 2 to the Company s Annual Report on Form 10 K/A filed with the SEC on July 6, 2009.
10.84	Crude Oil Purchase Agreement Sunoco Reference No. 502606 dated February 1, 2000 between Sunoco, Inc. and Ladder Energy Company (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.119 to Amendment No. 2 to the Company s Annual Report on Form 10 K/A filed with the SEC on July 6, 2009.
10.85	Letter of Amendment to the Crude Oil Purchase Agreement Sunoco Reference No. 502606 dated September 2, 2005 between Sunoco Partners Marketing & Terminals L.P. and Ladder Energy Company (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.120 to Amendment No. 2 to the Company s Annual Report on Form 10 K/A filed with the SEC on July 6, 2009.
10.86	Letter of Amendment to the Crude Oil Purchase Agreement Sunoco Reference No. 502606 dated September 26, 2006 between Sunoco Partners Marketing & Terminals L.P. and Ladder Energy Company (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.121 to Amendment No. 2 to the Company s Annual Report on Form 10 K/A filed with the SEC on July 6, 2009.

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10.87	Letter of Amendment to the Crude Oil Purchase Agreement Sunoco Reference No. 502606 dated September 11, 2008 between Sunoco Partners Marketing & Terminals L.P. and Ladder Energy Company (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.122 to Amendment No. 2 to the Company s Annual Report on Form 10 K/A filed with the SEC on July 6, 2009.
10.88	Crude Oil Purchase Agreement Sunoco Reference No. 521329 dated March 1, 2004 between Sunoco Partners Marketing & Terminals L.P. and Square One Energy (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.123 to Amendment No. 2 to the Company s Annual Report on Form 10 K/A filed with the SEC on July 6, 2009.
10.89	Letter of Amendment to the Crude Oil Purchase Agreement Sunoco Reference No. 521329 dated December 4, 2006 between Sunoco Partners Marketing & Terminals L.P. and Square One Energy, Inc. (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.124 to Amendment No. 2 to the Company s Annual Report on Form 10 K/A filed with the SEC on July 6, 2009.
10.90	Letter of Amendment to the Crude Oil Purchase Agreement Sunoco Reference No. 521329 dated February 16, 2009, between Sunoco Partners Marketing & Terminals L.P. and Square One Energy, Inc. (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.125 to Amendment No. 2 to the Company s Annual Report on Form 10 K/A filed with the SEC on July 6, 2009.
10.91	Letter of Amendment to the Crude Oil Purchase Agreement Sunoco Reference No. 521329 dated April 2, 2009, between Sunoco Partners Marketing & Terminals L.P. and Square One Energy (confidential treatment has been requested for this exhibit and confidential portions have been filed with the SEC), incorporated herein by reference to Exhibit 10.126 to Amendment No. 2 to the Company s Annual Report on Form 10 K/A filed with the SEC on July 6, 2009.
10.92+	Summary of 2009 Cash Incentive Awards, incorporated herein by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q filed with the SEC on November 10, 2008.
10.93+	Consulting Agreement dated October 1, 2008 between Cano Petroleum, Inc. and Morris B. Smith, incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on October 6, 2008.
10.94+	Amendment to Employment Agreement of Phillip Feiner dated September 8, 2008, incorporated herein by reference to Exhibit 10.3 to the Company s Quarterly Report on Form 10-Q filed with the SEC on November 10, 2008.
10.95	Letter Agreement Regarding Payment of Prepayment Premium dated September 30, 2008 between Unionbancal Equities, Inc. and Cano Petroleum, Inc., incorporated herein by reference to Exhibit 10.4 to the Company s Quarterly Report on Form 10-Q filed with the SEC on November 10, 2008.
10.96	Letter Agreement dated November 19, 2008 between Union Bank of California, NA and Cano Petroleum, Inc., incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 10-Q filed with the SEC on November 20, 2008.
10.97	Letter Agreement dated November 19, 2008 between Unionbancal Equities, Inc. and Cano Petroleum, Inc., incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 10-Q filed with the SEC on November 20, 2008.
10.98	Temporary Waiver of Benefits dated October 28, 2008 between S. Jeffrey Johnson and Cano Petroleum, Inc., incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on July 8, 2009.
10.99+	First Amendment to the Cano Petroleum, Inc. 2008 Annual Incentive Plan dated October 20, 2008, incorporated herein by reference to Exhibit 10.6 to the Company s Quarterly Report on Form 10-Q filed with the SEC on February 9, 2009.
10.100	$120,000,000 Amended and Restated Credit Agreement dated December 17, 2008 between Cano Petroleum, Inc. as Borrower, The Lenders Party Thereto From Time to Time as Lenders, and Union Bank of California, N.A. as Administrative Agent, incorporated herein by reference to Exhibit 10.7 to the Company s Quarterly Report on Form 10-Q filed with the SEC on February 9, 2009.
10.101	$25,000,000 Subordinated Credit Agreement dated December 17, 2008 among Cano Petroleum, Inc. as Borrower, The Lenders Party Thereto From Time to Time as Lenders, and UnionBanCal Equities, Inc. as Administrative Agent and as Issuing Lender, incorporated herein by reference to Exhibit 10.8 to the Company s Quarterly Report on Form 10-Q filed with the SEC on February 9, 2009.

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10.102	Amended and Restated Guaranty Agreement dated December 17, 2008 by Square One Energy, Inc., Ladder Companies, Inc., W.O. Energy of Nevada, Inc., WO Energy, Inc., W.O. Operating Company, Ltd., W.O. Production Company, Ltd. and Cano Petro of New Mexico, Inc. in favor of Union Bank of California, N.A. as Administrative Agent, incorporated herein by reference to Exhibit 10.9 to the Company s Quarterly Report on Form 10-Q filed with the SEC on February 9, 2009.
10.103	Subordinated Guaranty Agreement dated December 17, 2008 by Square One Energy, Inc., Ladder Companies, Inc., W.O. Energy of Nevada, Inc., WO Energy, Inc., W.O. Operating Company, Ltd., W.O. Production Company, Ltd. and Cano Petro of New Mexico, Inc. in favor of UnionBanCal Equities, Inc. as Administrative Agent, incorporated herein by reference to Exhibit 10.10 to the Company s Quarterly Report on Form 10-Q filed with the SEC on February 9, 2009.
10.104	Amended and Restated Pledge Agreement dated December 17, 2008 among Cano Petroleum, Inc., WO Energy, Inc. and W.O. Energy of Nevada, Inc. and Union Bank of California, N.A., as Administrative Agent, incorporated herein by reference to Exhibit 10.11 to the Company s Quarterly Report on Form 10-Q filed with the SEC on February 9, 2009.
10.105	Subordinated Pledge Agreement dated December 17, 2008 among Cano Petroleum, Inc., W.O. Energy, Inc. and W.O. Energy of Nevada, Inc. and UnionBanCal Equities, Inc., as Administrative Agent, incorporated herein by reference to Exhibit 10.12 to the Company s Quarterly Report on Form 10-Q filed with the SEC on February 9, 2009.
10.106	Amended and Restated Security Agreement dated December 17, 2008 among Cano Petroleum, Inc., Square One Energy, Inc., Ladder Companies, Inc., W.O. Energy of Nevada, Inc., W.O. Energy, Inc., W.O. Operating Company, Ltd., W.O. Production Company, Ltd. and Cano Petro of New Mexico, Inc. and Union Bank of California, N.A., as Administrative Agent, incorporated herein by reference to Exhibit 10.13 to the Company s Quarterly Report on Form 10-Q filed with the SEC on February 9, 2009.
10.107	Subordinated Security Agreement dated December 17, 2008 among Cano Petroleum, Inc., Square One Energy, Inc., Ladder Companies, Inc., W.O. Energy of Nevada, Inc., W.O. Energy, Inc., W.O. Operating Company, Ltd., W.O. Production Company, Ltd. and Cano Petro of New Mexico, Inc. and UnionBanCal Equities, Inc., as Administrative Agent, incorporated herein by reference to Exhibit 10.14 to the Company s Quarterly Report on Form 10-Q filed with the SEC on February 9, 2009.
10.108+	Second Amendment to Employment Agreement dated December 31, 2008 between Cano Petroleum, Inc. and S. Jeffrey Johnson, incorporated herein by reference to Exhibit 10.15 to the Company s Quarterly Report on Form 10-Q filed with the SEC on February 9, 2009.
10.109+	First Amendment to Employment Agreement dated December 31, 2008 between Cano Petroleum, Inc. and Ben Daitch, incorporated herein by reference to Exhibit 10.16 to the Company s Quarterly Report on Form 10-Q filed with the SEC on February 9, 2009.
10.110+	Fourth Amendment to Employment Agreement dated December 31, 2008 between Cano Petroleum, Inc. and Patrick M. McKinney, incorporated herein by reference to Exhibit 10.17 to the Company s Quarterly Report on Form 10-Q filed with the SEC on February 9, 2009.
10.111+	Fifth Amendment to Employment Agreement dated December 31, 2008 between Cano Petroleum, Inc. and Michael J. Ricketts, incorporated herein by reference to Exhibit 10.18 to the Company s Quarterly Report on Form 10-Q filed with the SEC on February 9, 2009.
10.112+	Second Amendment to Employment Agreement dated December 31, 2008 between Cano Petroleum, Inc. and Phillip Feiner, incorporated herein by reference to Exhibit 10.19 to the Company s Quarterly Report on Form 10-Q filed with the SEC on February 9, 2009.
10.113	Agreement and Plan of Merger, dated September 29, 2009, by and among Resaca Exploitation, Inc., Resaca Acquisition Sub, Inc. and Cano Petroleum, Inc., incorporated by reference from Exhibit 2.1 to Current Report on Form 8-K filed on October 1, 2009.
10.114	Gas Purchase Agreement by and between W.O. Operating Company Ltd. and DCP Midstream, L.P. effective on July 1, 2009, incorporated herein by reference to Exhibit 10.2 to the Company s Quarterly Report on Form 10-Q filed with the SEC on November 13, 2009.
10.115	Stock Voting Agreement, dated as of September 29, 2009, by and between Cano Petroleum, Inc. and D.E. Shaw Laminar Portfolios, L.L.C., incorporated by reference from Exhibit 10.1 to Current Report on Form 8-K filed on October 1, 2009.
10.116+	Separation Agreement and Release, dated as of September 29, 2009, by and among Cano Petroleum, Inc., Resaca Exploitation, Inc. and S. Jeffrey Johnson, incorporated by reference from Exhibit 10.2 to Current Report on Form 8-K filed on October 1, 2009.
10.117+	Separation Agreement and Release, dated as of September 29, 2009, by and among Cano Petroleum, Inc., Resaca Exploitation, Inc. and Benjamin L. Daitch, incorporated by reference from Exhibit 10.3 to Current Report on Form 8-K filed on October 1, 2009.

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10.118	Form of Stock Voting Agreement between Cano Petroleum, Inc. and certain holders of Series D Convertible Preferred Stock of Cano Petroleum, Inc., incorporated herein by reference to Exhibit 10.1 to Cano s Current Report on Form 8-K filed with the SEC on October 21, 2009.
10.119+	Form of Stock Voting Agreement between Cano Petroleum, Inc. and S. Jeffrey Johnson, incorporated herein by reference to Exhibit 10.2 to Cano s Current Report on Form 8-K filed with the SEC on October 21, 2009.
10.120	Amendment No. 1 and Agreement dated December 30, 2009, among Cano Petroleum, Inc., certain Guarantors, certain Lenders and Union Bank, N.A., incorporated herein by reference to Exhibit 10.1 to Cano s Current Report on Form 8-K filed with the SEC on January 6, 2010.
10.121	Amendment No. 1 and Agreement dated December 30, 2009, among Cano Petroleum, Inc., certain Guarantors, certain Lenders and UnionBanCal Equities, Inc., incorporated herein by reference to Exhibit 10.2 to Cano s Current Report on Form 8-K filed with the SEC on January 6, 2010.
10.122	Amendment No. 1 dated February 24, 2010, to Agreement and Plan of Merger, dated September 29, 2009, by and among Resaca Exploitation, Inc., Resaca Acquisition Sub, Inc. and Cano Petroleum, Inc., incorporated by reference from Exhibit 10.1 to Cano s Current Report on Form 8-K filed on February 25, 2010.
10.123	Amendment No. 2 dated April 1, 2010, to Agreement and Plan of Merger, dated September 29, 2009, by and among Resaca Exploitation, Inc., Resaca Acquisition Sub, Inc. and Cano Petroleum, Inc., incorporated by reference from Exhibit 10.1 to Cano s Current Report on Form 8-K filed on April 6, 2010.
10.124	Amendment No. 3 dated April 28, 2010, to Agreement and Plan of Merger, dated September 29, 2009, by and among Resaca Exploitation, Inc., Resaca Acquisition Sub, Inc. and Cano Petroleum, Inc., incorporated by reference from Exhibit 10.1 to Cano s Current Report on Form 8-K filed on April 29, 2010.
10.125	Amendment No. 2 and Agreement dated March 30, 2010, among Cano, certain Guarantors, certain Lenders and Union Bank, N.A., incorporated herein by reference to Exhibit 10.1 to Cano s Current Report on Form 8-K filed with the SEC on March 31, 2010.
10.126	Amendment No. 2 and Agreement dated March 30, 2009, among Cano, certain Guarantors, certain Lenders and UnionBanCal Equities, Inc., incorporated herein by reference to Exhibit 10.2 to Cano s Current Report on Form 8-K filed with the SEC on March 31, 2010.
10.127	Investors Rights Agreement, dated April 5, 2010, by and among Resaca, Cano and the holders of Resaca preferred stock, incorporated herein by reference to Exhibit 10.2 to Cano s Current Report on Form 8-K filed with the SEC on April 6, 2010.
10.128	Amendment No. 4 dated May 19, 2010, to Agreement and Plan of Merger, dated September 29, 2009, by and among Resaca Exploitation, Inc., Resaca Acquisition Sub, Inc. and Cano Petroleum, Inc., incorporated by reference from Exhibit 10.1 to Cano s Current Report on Form 8-K filed on May 20, 2010.
10.129	Consent and Forbearance Agreement dated August 5, 2010, among Cano, certain Guarantors, certain Lenders and Union Bank, N.A., incorporated herein by reference to Cano s current report on Form 8-K filed with the SEC on August 10, 2010.
10.130	Consent and Forbearance Agreement dated August 5, 2010, among Cano, certain Guarantors, certain Lenders and UnionBanCal Equities, Inc., incorporated herein by reference to Cano s current report on Form 8-K filed with the SEC on August 10, 2010.
10.131+	Sixth Amendment to Employment Agreement dated November 11, 2010, between the Company and Michael J. Ricketts, incorporated herein by reference to Exhibit 10.1 to the Company s current report on Form 8-K filed with the SEC on November 17, 2010.
10.132+	Separation Agreement and Release dated November 11, 2010, between the Company and Benjamin Daitch, incorporated herein by reference to Exhibit 10.2 to the Company s current report on Form 8-K filed with the SEC on November 17, 2010.
10.133+	Engagement Letter dated February 10, 2011, by and between Cano Petroleum, Inc. and Blackhill Partners LLC, incorporated by reference to Exhibit 10.1 to the Company s current report on Form 8-K filed with the SEC on February 16, 2011.
10.134+	Amended and Restated Employment Agreement effective as of February 11, 2011, between the Company and Michael J. Ricketts., incorporated by reference to Exhibit 10.134 to the Company s quarterly report on Form 10-Q filed with the SEC on May 13, 2011.
12.1*	Ratio of Earnings to Fixed Charges.
21.1*	Subsidiaries of the Company.
23.1*	Consent of Hein & Associates LLP.
23.2*	Consent of Miller & Lents, Ltd., Independent Petroleum Engineers.
23.3*	Consent of Haas Petroleum Engineering Services, Inc., Independent Petroleum Engineers.
24.1*	Power of Attorney (included on the signature page hereto).

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31.1*	Certification by Chief Executive Officer, required by Rule 13a-14(a) or Rule 15d-14(a) of the Exchange Act, promulgated pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification by Chief Financial Officer, required by Rule 13a-14(a) or Rule 15d-14(a) of the Exchange Act, promulgated pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification by Chief Executive Officer, required by Rule 13a-14(b) or Rule 15d-14(b) of the Exchange Act and Section 1350 of Chapter 63 of Title 18 of the United States Code, promulgated pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification by Chief Financial Officer, required by Rule 13a-14(b) or Rule 15d-14(b) of the Exchange Act and Section 1350 of Chapter 63 of Title 18 of the United States Code, promulgated pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of Haas Petroleum Engineering Services, Inc.

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* Filed herewith.

\+ Management contract or compensatory plan, contract or arrangement.

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of

Cano Petroleum, Inc.

We have audited the consolidated balance sheets of Cano Petroleum, Inc. and subsidiaries (collectively, the Company) as of June 30, 2011 and 2010, and the related consolidated statements of operations, changes in stockholders equity (deficit) and cash flows for each of the three years in the period ended June 30, 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. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Cano Petroleum, Inc. and subsidiaries as of June 30, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2011, in conformity with U.S. generally accepted accounting principles.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the financial statements, the Company has suffered recurring losses from operations and has a net capital deficiency that raise substantial doubt about its ability to continue as a going concern. Management s plans in regard to these matters are also described in Note 2. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ Hein & Associates LLP

Dallas, Texas

October 20, 2011

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CANO PETROLEUM, INC.

CONSOLIDATED BALANCE SHEETS

(Unaudited)

In Thousands, Except Shares and Per Share Amounts		**June 30, 2011**		**June 30, 2010**
ASSETS				
Current assets				
Cash and cash equivalents	$	1,694	$	300
Accounts receivable		2,300		2,411
Derivative assets				2,968
Deferred tax asset				17
Inventory and other current assets		694		841
Total current assets		4,688		6,537
Oil and gas properties, successful efforts method		295,560		294,961
Less accumulated depletion, depreciation and impairment		(235,997)		(44,615)
Net oil and gas properties		59,563		250,346
Fixed assets and other, net		1,085		2,404
Goodwill		101		101
TOTAL ASSETS	**$**	**65,437**	**$**	**259,388**
LIABILITIES, TEMPORARY EQUITY AND STOCKHOLDERS EQUITY/ (DEFICIT)				
Current liabilities				
Accounts payable	$	4,005	$	3,297
Accrued liabilities		4,901		2,304
Oil and gas sales payable		1,009		804
Derivative liabilities		5,292		410
Debt (Note 5)		66,450		66,450
Series D convertible preferred stock net of unamortized discount of $0.3 million and cumulative paid-in-kind dividends; par value $.0001 per share, stated value $1,000 per share; 49,116 shares authorized; 29,213 issued at June 30, 2011; liquidation preference at June 30, 2011 of $29.2 million		28,898		
Current portion of asset retirement obligations		208		189
Total current liabilities		110,763		73,454
Long-term liabilities				
Asset retirement obligations		4,487		2,991
Derivative liabilities		2,602		1,368
Deferred tax liabilities and other		950		18,992
Total liabilities		118,802		96,805
Temporary equity				
Series D convertible preferred stock and cumulative paid-in-kind dividends; par value $0.0001 per share, stated value $1,000 per share; 49,116 shares authorized; 28,100 issued at June 30, 2010.				26,518
Commitments and contingencies (Note 15)				
Stockholders equity/ (deficit)				
Common stock, par value $.0001 per share; 100,000,000 authorized; 47,057,992 and 45,354,915 shares issued and outstanding, respectively, at June 30, 2011; and 47,159,706 and 45,456,629 shares issued and outstanding, respectively, at June 30, 2010		5		5
Additional paid-in capital		189,916		190,500

Accumulated deficit		(242,589)		(53,743)
Treasury stock, at cost; 1,703,077 shares		(697)		(697)
Total stockholders equity/ (deficit)		(53,365)		136,065
TOTAL LIABILITIES, TEMPORARY EQUITY AND STOCKHOLDERS EQUITY/ (DEFICIT)	**$**	**65,437**	**$**	**259,388**

See accompanying notes to these consolidated financial statements.

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CANO PETROLEUM, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

In Thousands, Except Per Share Data	2011	Years Ended June 30, 2010	2009
Operating Revenues:			
Crude oil sales	$ 22,341	$ 19,642	$ 19,155
Natural gas sales	3,786	3,207	3,966
Other revenue			312
Total operating revenues	26,127	22,849	23,433
Operating Expenses:			
Lease operating	12,725	15,720	18,535
Production and ad valorem taxes	2,069	1,856	2,111
General and administrative	6,844	11,818	19,156
Exploration expense		5,024	11,379
Impairment of oil & gas properties	172,890	283	26,670
Depletion and depreciation	19,849	4,978	5,666
Accretion of discount on asset retirement obligations	338	287	303
Total operating expenses	214,715	39,966	83,820
Loss from operations	(188,588)	(17,117)	(60,387)
Other income (expense):			
Interest expense and other	(6,431)	(1,016)	(450)
Impairment of goodwill			(685)
Loss on sale of equipment used in oil and gas operations	(822)		
Gain (loss) on derivatives	(8,836)	(1,925)	43,790
Total other income (expense)	(16,089)	(2,941)	42,655
Loss from continuing operations before income taxes	(204,676)	(20,058)	(17,732)
Deferred income tax benefit	18,975	6,462	5,183
Loss from continuing operations	(185,701)	(13,596)	(12,549)
Income from discontinued operations, net of related taxes		2,057	12,318
Net loss	(185,701)	(11,539)	(231)
Preferred stock dividend	(3,145)	(1,829)	(2,730)
Preferred stock repurchased for less than carrying amount			10,890
Net (income)/ loss applicable to common stock	$ (188,846)	$ (13,368)	$ 7,929
Net income/ (loss) per share - basic and diluted			
Continuing operations	$ (4.16)	$ (0.34)	$ (0.10)
Discontinued operations		0.05	0.27
Net loss per share - basic and diluted	$ (4.16)	$ (0.29)	$ 0.17
Weighted average common shares outstanding			
Basic and Diluted	45,426	45,560	45,980

See accompanying notes to these consolidated financial statements.

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CANO PETROLEUM, INC.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY/ (DEFICIT)

JULY 1, 2010 THROUGH JUNE 30, 2011

Dollar Amounts in Thousands	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Deficit	Treasury Stock Shares	Treasury Stock Amount	Total Stockholders Equity (Deficit)
Balance at July 1, 2008	**40,523,168**	**$ 4**	**$ 121,831**	**$ (37,414)**	**1,268,294**	**$ (571)**	**$ 83,850**
Net proceeds from issuance of common shares on July 1, 2008	7,000,000	1	53,907				53,908
Forfeiture and surrender of restricted stock	(225,258)		(261)				(261)
Stock-based compensation			3,159				3,159
Preferred stock dividend				(2,730)			(2,730)
Preferred stock repurchased for less than carrying amount			10,890				10,890
Shares returned to treasury stock from escrow related to acquisition of W.O. Energy of Nevada, Inc. (Note 17)					434,783	(126)	(126)
Net loss				(231)			(231)
Balance at June 30, 2009	**47,297,910**	**5**	**189,526**	**(40,375)**	**1,703,077**	**(697)**	**148,459**
Forfeiture and surrender of restricted stock	(143,054)		(71)				(71)
Stock-based compensation expense			1,043				1,043
Net proceeds from issuance of common shares	4,850		2				2
Preferred stock dividend				(1,829)			(1,829)
Net loss				(11,539)			(11,539)
Balance at June 30, 2010	**47,159,706**	**5**	**190,500**	**(53,743)**	**1,703,077**	**(697)**	**136,065**
Forfeiture and surrender of stock awards	(111,214)		(9)				(9)
Stock-based compensation expense/ (benefit)			(579)				(579)

Net proceeds from issuance of common shares	9,500		4				4
Preferred stock dividend				(3,145)			(3,145)
Net loss				(185,701)			(185,701)
Balance at June 30, 2011	**47,057,992**	**$ 5**	**$ 189,916**	**$ (242,589)**	**1,703,077**	**$ (697)**	**$ (53,365)**

See accompanying notes to these consolidated financial statements.

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CANO PETROLEUM, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Dollar Amounts in Thousands	Year Ended June 30, 2011 2011	2010	2009
Cash flow from operating activities:			
Net loss	$ (185,701)	$ (11,539)	$ (231)
Adjustments needed to reconcile net loss to net cash provided by (used in) operations:			
Realized/ unrealized loss on derivatives	9,318	6,591	(36,900)
Loss on sale of equipment used in oil and gas operations	822		
Gain on sale of oil and gas properties		(2,478)	(19,246)
Settlement of asset retirement obligations		(314)	
Accretion of discount on asset retirement obligations	338	284	308
Depletion and depreciation	19,849	5,005	5,735
Exploration expense		5,024	11,379
Impairment of oil & gas properties	172,890	283	30,186
Impairment of goodwill			685
Stock-based compensation expense (benefit)	(579)	1,043	3,159
Deferred income tax benefit	(18,975)	(5,288)	1,731
Treasury stock			(126)
Amortization of debt issuance costs and prepaid expenses	906	1,758	1,457
Changes in assets and liabilities relating to operations:			
Accounts receivable	(123)	831	1,408
Derivative assets		(346)	2,423
Inventory and other current assets and liabilities	147	(1,402)	(1,473)
Accounts payable	708	622	(833)
Accrued liabilities	2,976	(285)	(6,271)
Net cash provided by (used in) operations	**2,576**	**(211)**	**(6,609)**
Cash flow from investing activities:			
Additions to oil and gas properties, fixed assets and other	(1,992)	(16,041)	(57,535)
Proceeds from sale of oil and gas properties		6,173	40,186
Proceeds from sale of equipment used in oil and gas operations	806		
Net cash used in investing activities	**(1,186)**	**(9,868)**	**(17,349)**
Cash flow from financing activities:			
Repayments of long-term debt	(550)	(3,000)	(128,500)
Borrowings of long-term debt	550	13,750	110,700
Payments for debt issuance costs			(933)
Proceeds from issuance of common stock, net	4	2	53,908
Repurchases of preferred stock			(10,377)
Payment of preferred stock dividend		(765)	(1,145)
Net cash provided by financing activities	**4**	**9,987**	**23,653**
Net increase in cash and cash equivalents	1,394	(92)	(305)
Cash and cash equivalents at beginning of period	300	392	697
Cash and cash equivalents at end of period	**$ 1,694**	**$ 300**	**$ 392**
Supplemental disclosure of noncash transactions:			
Payments of preferred stock dividend in kind	$ 1,113	$ 1,113	$ 1,585
Preferred stock repurchased for less than carrying amount			$ 10,890

Supplemental disclosure of cash transactions:						
Cash paid during the period for interest	$	3,444	$	2,912	$	1,852

See accompanying notes to these consolidated financial statements.

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CANO PETROLEUM, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION

As of June 30, 2011, Cano Petroleum, Inc. (together with its direct and indirect subsidiaries, Cano, we, us, or the Company) is an independent o and natural gas company based in Irving Texas. In the past, our strategy had been to convert our estimated proved undeveloped reserves into proved producing reserves, improve operational efficiencies in our existing properties and acquire accretive proved producing assets suitable for secondary and enhanced oil recovery at low cost. Due to the Company s current financial constraints, including continued losses, defaults under our loan agreements and our Series D Preferred Stock, no available borrowing capacity, constrained cash flow, negative working capital, and limited to no other capital availability, we are reviewing strategic alternatives which include the sale of the Company, the sale of some or all of our existing oil and gas properties and assets, potential business combinations, debt restructuring, including recapitalizing the Company, and bankruptcy. We continue to focus on cash management and cost reduction efforts to improve both our cash flow from operations and profitability. Our assets are located onshore U.S. in Texas, New Mexico, and Oklahoma.

2. LIQUIDITY / GOING CONCERN

Due to the Company s current financial condition, including continued losses, defaults under its loan agreements, no available borrowing capacity, constrained cash flow, and negative working capital, and limited to no access to additional capital, the Company s auditors reported that there is substantial doubt about our ability to continue as a going concern.

At June 30, 2011, we had cash and cash equivalents of $1.7 million. We had negative working capital of $106.1 million, which includes $66.5 million of long-term debt that was shown as a current liability and $28.9 million of our Series D Preferred Stock, which was redeemable in cash on September 6, 2011. For the year ended June 30, 2011, we had cash flow provided by operations of $2.6 million.

On July 20, 2010, we terminated our announced merger with Resaca Exploitation, Inc. (Resaca) that had been initiated pursuant to an Agreement and Plan of Merger dated September 29, 2009. On July 26, 2010, we announced the engagement of Canaccord Genuity Inc. and Global Hunter Securities to assist our management and board of directors in a review of strategic alternatives with the goal of maximizing economic value for our stakeholders. We believe that these alternatives include the following: sale of the Company; sale of some or all of our existing oil and gas properties and assets; business combinations; debt restructuring, including recapitalizing the Company, with or without bankruptcy; and bankruptcy. That review is ongoing.

On August 5, 2010, we finalized Consent and Forbearance Agreements with the lenders under our credit agreements that waived potential covenant compliance issues for the periods ending June 30, 2010, and September 30, 2010, set certain deadlines for the execution of our strategic alternatives process and allowed us to sell certain natural gas commodity derivative contracts for cash proceeds of $0.8 million, which was intended to provide Cano sufficient liquidity to complete its strategic alternatives process. The Consent and Forbearance Agreements were terminated as our lenders delivered Reservation of Rights Letters dated September 24, 2010, January 5, 2011, and September 23, 2011. We continue to work with our lenders and advisors as we consider strategic alternatives. As of October 20, 2011, our lenders have taken no definitive actions associated with the termination of the Consent and Forbearance Agreements. As discussed in Note 5, we currently have no available borrowing capacity under our senior and subordinated credit agreements.

We were required to redeem the Preferred Stock that remained outstanding on September 6, 2011 for a redemption amount in cash equal to the stated value of the Preferred Stock, plus accrued dividends and PIK dividends. However, the subordination provisions of the Preferred Stock prohibit us from redeeming the Preferred Stock while we are in default under our senior credit agreement. As a result of our defaults under our senior and subordinated credit agreements, we were not able to redeem the outstanding Preferred Stock as of its maturity date. Without successfully implementing one of our strategic alternatives or restructuring our existing indebtedness, we do not expect to be able to cure our defaults under our senior and subordinated credit agreements any time in the foreseeable future. Accordingly, we do not expect to be able to redeem our outstanding Preferred Stock in the foreseeable future.

Our universal shelf registration statement, declared effective by the SEC on December 28, 2007 for the issuance of common stock, preferred stock, warrants, senior debt and subordinated debt up to an aggregate amount of $150.0 million, expired on December 31, 2010.

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The accompanying consolidated financial statements have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets and liquidation of liabilities in the ordinary course of business. There is no assurance that the carrying amounts of assets will be realized or that liabilities will be settled for the amounts recorded, or that the Company can continue to prepare future financial statements on a going concern basis. The ability of the Company to continue as a going concern will be dependent upon the outcome of our strategic alternatives review, crude oil and natural gas prices, sufficient liquidity to fund operations, actions by our lenders, mechanical problems at our wells and/or catastrophic events such as fires, hurricanes and floods. If we are unable to successfully execute one of our strategic alternatives, restructure our existing indebtedness, obtain further waivers or forbearance from our existing lenders or otherwise raise significant additional capital, it is unlikely that we will be able to meet our obligations as they become due and to continue as a going concern. As a result, we will likely file for bankruptcy or seek similar protection. Moreover, it is possible that our creditors may seek to initiate involuntary bankruptcy proceedings against us or against one or more of our subsidiaries, which would force us to make defensive voluntary filing(s) of our own. In addition, if we restructure our debt or file for bankruptcy protection, it is very likely that our common stock and preferred stock will be severely diluted if not eliminated entirely.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Use of Estimates

The accompanying financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) and include the accounts of Cano and its wholly-owned subsidiaries. Intercompany accounts and transactions are eliminated. In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies. Actual results may differ from those estimates. Significant assumptions are required in the valuation of estimated proved crude oil and natural gas reserves, which may affect the amount at which crude oil and natural gas properties are recorded. The computation of share-based compensation expense requires assumptions such as volatility, expected life and the risk-free interest rate. Our liabilities and assets associated with commodity derivatives involve significant assumptions related to volatility and future prices for crude oil and natural gas. It is at least reasonably possible these estimates could be revised in the near term, and these revisions could be material.

Cano s Proved Reserves

The term proved reserves is defined by the SEC in Rule 4-10(a) of Regulation S-X adopted under the Securities Act of 1933, as amended. In general, proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods, and government regulations. Prices are based on an unweighted arithmetic average of the first-day-of-the-month prices for each month within Fiscal Year 2011. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based on future conditions.

A decline in estimates of proved reserves may result from lower prices, new information obtained from development drilling and production history, field tests, data analysis, economic factors including expectation and assumptions as to availability of financing for development projects, mechanical problems on our wells; and catastrophic events such as explosions, hurricanes and floods. Lower prices also may make it uneconomical to drill wells or produce from fields having high operating costs.

Our estimates of proved reserves materially affect depletion expense. If estimated proved reserves decline, then the rate at which we record depletion expense increases. In addition, a decline in estimated proved reserves may affect our assessment of our oil and natural gas properties for impairment.

Our proved reserves estimates are a function of many assumptions, all of which could deviate materially from actual results. As such, reserves estimates may vary materially from the ultimate quantities of crude oil and natural gas actually produced.

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Oil and Gas Properties and Equipment

We follow the successful efforts method of accounting. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense. The costs of drilling and equipping exploratory wells are deferred until the Company has determined whether proved reserves have been found. If proved reserves are found, the deferred costs are capitalized as part of the wells and related equipment and facilities. If no proved reserves are found, the deferred costs are charged to expense. All development activity costs are capitalized. We are primarily engaged in the development and acquisition of crude oil and natural gas properties. Our activities are considered development where existing proved reserves are identified prior to commencement of the project and are considered exploration if there are no proved reserves at the beginning of such project. The property costs reflected in the accompanying consolidated balance sheets resulted from acquisition and development activities and deferred exploratory drilling costs. Capitalized overhead costs that directly relate to our drilling and development activities were nil and $0.8 million for the years ended June 30, 2011, and 2010, respectively. We recorded capitalized interest costs of $0.7 million and $2.0 million for the years ended June 30, 2011, and 2010, respectively.

Costs for repairs and maintenance to sustain or increase production from existing producing reservoirs are charged to expense. Significant tangible equipment added or replaced that extends the useful or productive life of the property is capitalized. Costs to construct facilities or increase the productive capacity from existing reservoirs are capitalized.

Depreciation and depletion of producing properties are computed on the unit-of-production method based on estimated proved oil and natural gas reserves. Our unit-of-production amortization rates are revised prospectively on a quarterly basis based on updated engineering information for our estimated proved developed reserves. Our development costs and lease and wellhead equipment are depleted based on estimated proved developed reserves. Our leasehold costs are depleted based on total estimated proved reserves. Investments in major development projects are not depleted until such project is substantially complete and producing or until impairment occurs.

If conditions indicate that long-term assets may be impaired, the carrying value of our properties is compared to management s future estimated undiscounted net cash flow from the properties. If undiscounted cash flows are less than the carrying value, then the asset value is written down to fair value. Impairment of individually significant unproved properties is assessed on a property-by-property basis, and impairment of other unproved properties is assessed and amortized on an aggregate basis. The impairment assessment is affected by factors such as the results of exploration and development activities, commodity price projections, remaining lease terms, and potential shifts in our business strategy.

Asset Retirement Obligation

Our financial statements reflect the fair value of our asset retirement obligation (ARO), which consists of future plugging and abandonment expenditures related to our oil and gas properties, that can be reasonably estimated, and discounted at our credit-adjusted risk-free rate. The asset retirement obligation is recorded as a liability at its estimated fair value at the asset s inception, with an offsetting increase to producing properties on the consolidated balance sheets, which is depreciated such that the cost of the ARO is recognized over the useful life of the asset. Periodic accretion of the discount of the estimated liability to its expected settlement value is recorded as an expense in the consolidated statements of operations.

Inherent in the fair value calculation of ARO are numerous assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions

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to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance.

Goodwill

The amount paid for certain acquisitions in excess of the fair value of the net assets acquired has been recorded as goodwill in the consolidated balance sheets. Goodwill is not amortized, but is assessed for impairment annually or whenever conditions would indicate impairment might exist. The goodwill impairment analysis is evaluated at the subsidiary level as part of the impairment analysis performed on oil and gas properties, as previously discussed.

Cash and Cash Equivalents

Cash equivalents are considered to be all highly liquid investments having an original maturity of three months or less. Excess cash funds are generally invested in U.S. government-backed securities. At times, we maintain deposit balances in excess of Federal Deposit Insurance Corporation insurance limits.

Accounts Receivable

Accounts receivable principally consist of crude oil and natural gas sales proceeds receivable and are typically collected within 35 days from the end of the month in which the related quantities are produced. We require no collateral for such receivables, nor do we charge interest on past due balances. We periodically review accounts receivable for collectability and reduce the carrying amount of the accounts receivable by an allowance. No such allowance was recorded at June 30, 2011, or 2010. As of June 30, 2011, our accounts receivable were primarily with independent purchasers of our crude oil and natural gas production. At June 30, 2011, we had balances due from four customers, which were greater than 10% of our accounts receivable related to crude oil and natural gas production. These four customers accounted for 40% (Valero Marketing Supply Co.), 18% (Andrews), 22% (Coffeyville Resources Refinery and Marketing, LLC) and 10% (Sunoco, Inc.) of our accounts receivable, respectively.

At June 30, 2010, we had balances due from three customers, which were greater than 10% of our accounts receivable related to crude oil and natural gas production. These three customers accounted for 42% (Valero Marketing Supply Co.), 19% (Coffeyville Resources Refinery and Marketing, LLC), and 18% (Plains Marketing, LP) of our accounts receivable, respectively.

In the event that one or more of these significant customers ceases doing business with us, we believe that there are potential alternative purchasers with whom we could establish new relationships and replace one or more lost purchasers. We would not expect the loss of any single purchaser to have a long-term material adverse effect on our operations, though we may experience a short-term decrease in our revenues as we arrange for alternative purchasers. However, the loss of a single purchaser could potentially reduce the competition for our crude oil and natural gas production, which could negatively affect the prices we receive.

Revenue Recognition

Our revenue recognition is based on the sales method. We do not have imbalances for natural gas sales since we are primarily the 100% working interest owner in our properties. We recognize revenue when crude oil and natural gas quantities are delivered to or collected by the respective purchaser. Title to the produced quantities transfers to the purchaser at the time the purchaser receives or collects the quantities. Prices for such production are defined in sales contracts and are readily determinable based on publicly available information. The purchasers of such production have historically made payment for crude oil and natural gas purchases within thirty-five days of the end of each production month. We periodically review the difference between the dates of production and the dates we collect payment for such production to ensure that accounts receivable from the purchasers are collectible. The point of sale for our crude oil and natural gas production is at our applicable field tank batteries and gathering systems;

therefore, we do not incur directly transportation costs related to our sales of crude oil and natural gas production.

As previously discussed, for the years ended June 30, 2011, 2010, and 2009, we sold our crude oil and natural gas production to several independent purchasers. The following table shows purchasers that accounted for 10% or more of our total operating revenues:

	Year Ended June 30,		
	2011	**2010**	**2009**
Valero Marketing Supply Co.	34%	33%	32%
Coffeyville Resources Refinery and Marketing, LLC	24%	22%	18%
Sunoco, Inc.	11%	*	*
Plains Marketing, LP	*	18%	15%
Eagle Rock Field Services, LP	*	*	13%
DCP Midstream, LP	*	10%	10%

* Less than 10% of operating revenue

Oil and Gas Sales Payable

Our accounts receivable includes amounts that we collect from the purchasers of our crude oil and natural gas sales on behalf of us, and certain working interest and royalty owners. The portion of accounts receivable that pertains to us is recognized as operating revenue. The portion that pertains to certain working interest and royalty owners are included in oil and gas sales payable on our consolidated balance sheets.

Inventory

Our inventory consists of unsold barrels of crude oil remaining in our storage tanks at the end of the period. We value these crude oil barrels based on the lower of market or our average production cost.

Income Taxes

Deferred tax assets or liabilities are recognized for the anticipated future tax effects of temporary differences between the financial statement basis and the tax basis of our assets and liabilities. These balances are measured using tax rates in effect for the year in which the differences are expected to reverse. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized. As of June 30, 2011, we have not recorded any accruals for uncertain tax positions. We are not involved in any examinations by the Internal Revenue Service. For Texas, Oklahoma, New Mexico and U.S. federal purposes, the review of our income tax returns is open for examination by the related taxing authorities for the tax years of 2004 through 2010.

Financial Instruments

The carrying amounts of financial instruments including cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities approximate fair value, unless otherwise stated, as of June 30, 2011, and 2010. The carrying amounts for derivative assets and liabilities are based on mark-to-market valuations.

Net Income (Loss) per Common Share

Diluted net income (loss) per common share is computed in the same manner as basic net income (loss) per common share, but also considers the effect of shares of common stock underlying the following:

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	Year Ended June 30, 2011	2010	2009
Stock options (Note 9)	1,071,630	1,310,710	1,400,002
Preferred Stock (Note 4)	4,147,652	4,147,652	4,147,652
Paid-in-kind dividends (PIK) (Note 4)	932,921	739,347	545,773

The shares of common stock underlying the stock options, Preferred Stock and PIK dividends, as shown in the preceding table, are not included in weighted average shares outstanding for the years ended June 30, 2011, 2010, or 2009 as their effects would be anti-dilutive.

Share-Based Compensation Expense

We account for share-based payment arrangements with employees and directors at their grant-date fair value and record the related expense over their respective service periods. The value of share-based compensation is impacted by our stock price, which has been highly volatile, and items that require management s judgment, such as expected lives and forfeiture rates.

Derivatives

We have historically maintained commodity derivative contracts for a portion of our crude oil and natural gas production, as discussed in Note 6. The purpose of the derivatives is to reduce our exposure to declining commodity prices. These derivatives are recorded as derivative assets and liabilities on our consolidated balance sheets based upon their respective fair values. We have also historically entered into interest rate basis swap contracts to reduce our exposure to future interest rate increases.

On August 22, 2011, we executed a mutual termination letter with Natixis providing for the termination of two fixed price commodity swap contracts that we entered into on September 11, 2009. In connection with the termination of the commodity swap transactions, we must pay $3.65 million to Natixis. On September 9, 2011, we executed a mutual termination letter with Natixis providing for the termination of the three-year LIBOR interest rate basis swap contract for $20.0 million in notional exposure that we entered into on January 12, 2009. In connection with the termination of the interest rate swap, we must pay $145,500 to Natixis. Upon these terminations, the total termination fees of approximately $3.8 million became senior obligations of the Company in addition to the amounts owed under the ARCA, and we no longer are a party to any derivative contract.

We do not designate our derivatives as cash flow or fair value hedges. We do not hold or issue derivatives for speculative or trading purposes. We are exposed to credit losses in the event of nonperformance by the counterparties to our commodity and interest rate swap derivatives. We anticipate, however, that our counterparties will be able to fully satisfy their respective obligations under our commodity and interest rate swap derivatives contracts. We do not obtain collateral or other security to support our commodity derivatives contracts nor are we required to post any collateral. We monitor the credit standing of our counterparties to understand our credit risk.

Changes in the fair values of our derivative instruments and cash flows resulting from the settlement of our derivative instruments are recorded in earnings as gains or losses on derivatives on our consolidated statements of operations.

Comprehensive Income

We had no elements of comprehensive income other than net loss for the years ended June 30, 2011, 2010, or 2009.

New Accounting Prounouncements

In January 2010, the FASB issued ASU 2010-06, *Fair Value Measurements and Disclosures (Topic 820)*. ASU 2010-06 Subtopic 820-10 provides new guidance on improving disclosures about fair value measurements. The new standard requires some new disclosures and clarifies some existing

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disclosure requirements about fair value measurement. Specifically, the new standard will now require: (a) a reporting entity should disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reasons for transfers and (b) in the reconciliation for fair value measurements using significant unoberservable inputs, a reporting entity should present separately information about purchases, sales, issuances, and settlements. In addition, the new standard clarifies the requirements of the following existing disclosures: (a) for purposes of reporting fair value measurements for each class of assets and liabilities, a reporting entity needs to use judgment in determining the appropriate classes of assets and liabilities and (b) a reporting entity should provide disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements. The new standard is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. Early application is permitted. The adoption of the requirements of this standard in the quarter ended March 31, 2010, did not have a material impact on our financial position or results of operations.

4. PREFERRED STOCK

On September 6, 2006, we sold $49.1 million of Preferred Stock. We were required to file a registration statement on Form S-1 with the Securities and Exchange Commission (the SEC) registering the resale of the common shares underlying the Preferred Stock, which was filed on October 13, 2006 and was declared effective on January 4, 2007. On April 9, 2007, we also filed to register these same common shares on a registration statement on Form S-3, which was declared effective on April 19, 2007. We are required to maintain the effectiveness of the registration statement until such common shares may be resold pursuant to Rule 144 under the Securities Act of 1933, as amended, or all such common shares have been resold subject to certain exceptions, and if the effectiveness is not maintained, then we must pay 1.5% of the gross proceeds and an additional 1.5% for every 30 days it is not maintained. The maximum aggregate of all registration delay payments is 10% of the gross proceeds from the September 2006 offering. We do not believe it is probable we will incur any penalties under this provision and accordingly have not accrued any loss.

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The Preferred Stock has a 7.875% dividend and features a paid-in-kind (PIK) provision that allows the investor, at its option, to receive additional shares of common stock upon conversion for the dividend in lieu of a cash dividend payment. Once the investor has chosen the PIK or cash distribution option, all future distributions follow the same choice. As of June 30, 2009, approximately 59% of the Preferred Stock dividends were PIK. The Preferred Stock is convertible at the holder s option to common stock at a price of $5.75 per share. We were required to redeem the Preferred Stock that remained outstanding on September 6, 2011for a redemption amount in cash equal to the stated value of the Preferred Stock, plus accrued dividends and PIK dividends. However, the subordination provisions of the Preferred Stock prohibit us from redeeming the Preferred Stock while we are in default under our senior credit agreement. As a result of our defaults under our senior and subordinated credit agreements, we were not able to redeem the outstanding Preferred Stock as of its maturity date. Without successfully implementing one of our strategic alternatives or restructuring our existing indebtedness, we do not expect to be able to cure our defaults under our senior and subordinated credit agreements any time in the foreseeable future. Accordingly, we do not expect to be able to redeem our outstanding Preferred Stock in the foreseeable future. The issuance of Preferred Stock has previously been accounted for as temporary equity since the holders could, subject to limitations of the subordination provisions, request redemption for cash under certain circumstances. As a result of our failure to redeem the Preferred Stock that remained outstanding on September 6, 2011 and our continuing defaults under our senior and subordinated credit agreements, the holders of our Preferred Stock have the option to require us to redeem all or a portion of the Preferred Stock at a price per share equal to the greater of (i) 125% of the Conversion Amount and (ii) the product of (A) the Conversion Rate in effect at such time and (B) the greater of the Closing Sale Price of the Common Stock on the Trading Day immediately preceding such Triggering Event, the Closing Sale Price of the Common Stock on the day immediately following such Triggering Event and the Closing Sale Price of the Common Stock on the date the Holder delivers the notice of redemption at the Holder s option, in all cases, as such terms are defined in the Certificate of Designations, Preferences and Rights of the Preferred Stock. The Preferred Stock is now accounted for as a current liability, since it has passed its maturity and the holders may, subject to limitations of the subordination provisions, request redemption for cash.

Pursuant to the terms of the Preferred Stock and subject to certain exceptions, if we issue or sell common stock at a price less than the conversion price (currently $5.75 per share) in effect immediately prior to such issuance or sale, the conversion price shall be reduced. If such an issuance is made, the conversion price will be lowered to the weighted average price of (x) the total common shares outstanding prior to said issuance multiplied by $5.75 and (y) the new shares issued at the new issuance price. The above described adjustment is not triggered by issuances or sales involving the following: (i) shares issued in connection with an employee benefit plan; (ii) shares issued upon conversion of our Preferred Stock; (iii) shares issued in connection with a firm commitment underwritten public offering with gross proceeds in excess of $50,000,000; (iv) shares issued in connection with any strategic acquisition or transaction; (v) shares issued in connection with any options or convertible securities that were outstanding on August 25, 2006; or (vi) shares issued in connection with any stock split, stock dividend, recapitalization or similar transaction.

Each holder of Preferred Stock is entitled to the whole number of votes equal to the number of shares of common stock issuable upon conversion. The Preferred Stock shall vote as a class with the holders of the common stock as if they were a single class of securities upon any matter submitted to the vote of the stockholders except those matters required by law or the terms of the Preferred Stock to be submitted to a class vote of the holders of the Preferred Stock, in which case the holders of the Preferred Stock only shall vote as a separate class.

Upon a voluntary or involuntary liquidation, dissolution or winding up of Cano or such subsidiaries of Cano the assets of which constitute all or substantially all of the assets of the business of Cano and its subsidiaries taken as a whole, the holders of our Preferred Stock shall be entitled to receive an amount per share equal to $1,000 plus dividends owed on such share prior to any payments being made to any class of capital stock ranking junior upon liquidation to the Preferred Stock.

At June 30, 2011, 29,213 shares of Series D Convertible Preferred Stock were outstanding (including 5,364 shares from PIK dividends). At June 30, 2010, 28,100 shares of Series D Convertible

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Preferred Stock were outstanding (including 4,251 shares from PIK dividends). At June 30, 2009, 26,987 shares of Series D Convertible Preferred Stock were outstanding (including 3,138 shares from PIK dividends). During November and December 2008, we repurchased 22,948 shares of Series D Convertible Preferred Stock, including accrued dividends and 2,323 shares from PIK dividends for approximately $10.4 million, realizing a gain of $10.9 million.

For the 2011 Fiscal Year, the preferred dividend was $3.1 million, of which $1.1 million were PIK dividends. For the year ended June 30, 2010, the preferred dividend was $1.8 million, of which $1.1 million were PIK dividends. For the year ended June 30, 2009, the preferred dividend was $2.7 million, of which $1.6 million were PIK dividends.

At June 30, 2011, the Preferred Stock and cumulative PIK dividends were convertible into 4,147,652 and 932,921 shares, respectively, of our common stock at a conversion price of $5.75 per share.

On August 5, 2010, we entered into Forbearance Agreements with the lenders under our credit agreements that prohibited us from making any indirect or direct cash payment, cash dividend or cash distribution in respect of our shares of Preferred Stock. As discussed in Notes 2 and 5, the Forbearance Agreements were terminated. As of June 30, 2011, we have not remitted cash dividend payments for the Preferred Stock of $3.1 million for the 2011 Fiscal Year. As of June 30, 2011, the unpaid cash dividend of $0.8 million is included in accrued liabilities reported in our consolidated balance sheets. Due to the non-payment of the cash dividends, along with the fact that the Preferred Stock is redeemable for cash as of September 6, 2011, our Preferred Stock has been reclassified from Temporary Equity to a current liability of $28.9 million on our consolidated balance sheet, which is the liquidation preference of $29.2 million less unamortized issuance costs of $0.3 million, which is presented as a discount on the consolidated balance sheet as of June 30, 2011. During the 2011 Fiscal Year, issuance costs of $1.3 million were amortized in preferred stock dividend. There have been no dividend payments in cash or redemptions of Preferred Stock during the year ended June 30, 2011 or at any time from June 30, 2011 through October 20, 2011.

S. Jeffrey Johnson, our former Chief Executive Officer and former Chairman of our board of directors, owns approximately 4.2% of our outstanding Preferred Stock. For the 2011 Fiscal Year, we made no preferred dividend payments to Mr. Johnson. For the 2010 Fiscal Year, we made preferred dividend payments to Mr. Johnson of $79,000.

5. DEBT

At June 30, 2011, the outstanding amount due under our credit agreements was $66.5 million. The $66.5 million consisted of outstanding borrowings under the amended and restated credit agreement (the ARCA) and the subordinated credit agreement (the SCA) of $51.5 million and $15.0 million, respectively. On August 22, 2011, our commodity hedges with the lenders were terminated at a cost of $3.65 million. On September 9, 2011, our interest rate hedge with the lenders was terminated at a cost of $145,500. Both of these amounts have become senior obligations of the Company in addition to the amounts owed under the ARCA. At June 30, 2011, the average interest rates charged by the lenders under the ARCA and SCA were 2.94% and 6.11%, respectively. As of September 12, 2011, we received notice from the agent for the ARCA that the outstanding Libor based loan advances under the ARCA will be converted to prime based advances as they mature. The Company has no borrowing capacity under either the ARCA or SCA.

Forbearance Agreements

On August 5, 2010, we executed a Consent and Forbearance Agreement (the Senior Forbearance Agreement) with Union Bank, N.A. (UBNA) and Natixis relating to existing and potential defaults under the ARCA dated December 17, 2008 among Cano, UBNA and Natixis and a Consent and

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Forbearance Agreement (together with the Senior Forbearance Agreement, the Forbearance Agreements) with UnionBanCal Equities, Inc. (UBE), relating to existing defaults under the SCA dated December 17, 2008 between Cano and UBE (as amended, the SCA and together with the ARCA, the Credit Agreements). Pursuant to the Forbearance Agreements, Natixis, UBNA and UBE agreed to forbear from exercising certain rights and remedies under the Credit Agreements arising as a result of certain defaults.

On September 24, 2010, our lenders delivered Reservation of Rights Letters (Letters), subsequently updated on January 5, 2011, and September 23, 2011, specifying that we failed to timely comply with the material terms of the Forbearance Agreements and therefore terminated the Forbearance Agreements. On August 31, 2011, we failed to make a required payment of interest under the ARCA. Our failure to make such payment of interest constituted an Event of Default under the ARCA and the SCA, for which the lenders under such credit agreements may terminate their obligation to extend credit to us and declare all amounts payable under the ARCA and the SCA due and payable in full. We have not received any notice from the lenders with respect to the exercise of their respective rights, including any right to accelerate the amounts payable by us. We continue to work with our lenders and advisors as we consider strategic alternatives.

We have recorded all additional interest and fees due under the terms of the Credit Agreements of $5.6 million in accrued liabilities on our consolidated balance sheet and in interest expense on consolidated statement of operations as of June 30, 2011. We have also recorded additional interest expense associated with the accelerated amortization of deferred financing costs of $0.9 million applicable to the Credit Agreements, and accounting and legal expense incurred by our lenders of $0.7 million.

ARCA

On December 17, 2008, we finalized a$120.0 million Amended and Restated Credit Agreement (the ARCA) with UBNA and Natixis. UBNA is the Administrative Agent and Issuing Lender of the ARCA. The current amount outstanding under the ARCA is equal to the commitment of $51.5 million. Further, $3.8 million of costs for the termination of our commodity hedges and interest rate hedge on August 22, 2011 and September 9, 2011, respectively are additional senior obligations of the Company. We are fully borrowed and have no further borrowing capacity under the ARCA. As of September 12, 2011, we received notice from the agent for the ARCA that the outstanding Libor based loan advances under the ARCA will be converted to prime based advances as they mature.

As discussed above, we are currently in default under the ARCA. Unless specific events of default occur, the maturity date of the ARCA is December 17, 2012. Specific events of default which could cause all outstanding principal and accrued interest to be accelerated, include, but are not limited to, payment defaults, material breaches of representations and warranties, breaches of covenants, certain cross-defaults, insolvency, a change in control or a material adverse change. If the bank causes all outstanding principal and accrued interest to be accelerated, we will likely be forced to file for bankruptcy or similar protection, unless we are able to successfully execute one of our strategic alternatives, restructure our existing indebtedness, obtain further waivers or forbearance from our existing lenders or otherwise raise significant additional capital. The ARCA contains certain negative covenants including, subject to certain exceptions, covenants against the following: (i) incurring additional liens, (ii) incurring additional debt or issuing additional equity interests other than common equity interests; (iii) merging or consolidating or selling, leasing, transferring, assigning, farming-out, conveying or otherwise disposing of any property, (iv) making certain payments, including cash dividends to our common stockholders, (v) making any loans, advances or capital contributions to, or making any investment in, or purchasing or committing to purchase any stock or other securities or evidences of indebtedness or interest in any person or oil and gas properties or activities related to oil and gas properties unless (a) with regard to new oil and gas properties, such properties are mortgaged to UBNA, as administrative agent, or (b) with regard to new subsidiaries, such subsidiaries execute a guaranty, pledge agreement, security agreement or mortgage in favor of UBNA, as administrative agent, and (vi) entering

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into affiliate transactions on terms that are not at least as favorable to us as comparable arm s length transactions.

SCA

On December 17, 2008, we finalized a $25.0 million SCA between Cano and UBE, as the Administrative Agent. On March 17, 2009, we borrowed the maximum available amount of $15.0 million under this agreement.

The interest rate is the sum of (a) the one, two or three month LIBOR rate (at our option) and (b) 6.0%. Through March 17, 2009, we owed a commitment fee of 1.0% on the unborrowed portion of the available borrowing amount. We no longer have a commitment fee since we borrowed the full $15.0 million available amount.

As discussed above, we are currently in default under the SCA. Unless specific events of default occur, the maturity date is June 17, 2013. Specific events of default which could cause all outstanding principal and accrued interest to be accelerated, include, but are not limited to, payment defaults, material breaches of representations and warranties, breaches of covenants, certain cross-defaults, insolvency, a change in control or a material adverse change as defined in the SCA. If the bank causes all outstanding principal and accrued interest to be accelerated, we will likely be forced to file for bankruptcy or similar protection, unless we are able to successfully execute one of our strategic alternatives, restructure our existing indebtedness, obtain further waivers or forbearance from our existing lenders or otherwise raise significant additional capital. The SCA contains certain negative covenants including, subject to certain exceptions, covenants against the following: (i) incurring additional liens, (ii) incurring additional debt or issuing additional equity interests other than common equity interests of Cano; (iii) merging or consolidating or selling, leasing, transferring, assigning, farming-out, conveying or otherwise disposing of any property, (iv) making certain payments, including cash dividends to our common stockholders, (v) making any loans, advances or capital contributions to, or making any investment in, or purchasing or committing to purchase any stock or other securities or evidences of indebtedness or interest in any person or oil and gas properties or activities related to oil and gas properties unless (a) with regard to new oil and gas properties, such properties are mortgaged to UBE, as administrative agent, or (b) with regard to new subsidiaries, such subsidiaries execute a guaranty, pledge agreement, security agreement or mortgage in favor of UBE, as administrative agent, and (vi) entering into affiliate transactions on terms that are not at least as favorable to us as comparable arm s length transactions.

Credit Agreement Covenant Compliance

At June 30, 2011, we were not in compliance with the ARCA and SCA covenants for Modified Current Ratio, Leverage Ratio or Interest Coverage Ratio. On August 31, 2011, we failed to make a required payment of interest under the ARCA.

6. DERIVATIVES

Our derivatives consist of commodity derivatives and an interest rate swap arrangement, which are discussed in greater detail below.

Commodity Derivatives

From time to time, we maintain commodity derivative contracts. We entered into commodity derivative contracts to partially mitigate the risk associated with extreme fluctuations of prices for our crude oil and natural gas sales. We have no obligation to enter into commodity derivative contracts in the future. Should we choose to enter into commodity derivative contracts to mitigate future price risk, we are prohibited under the ARCA from entering into contracts for greater than 85% of anticipated production volumes attributable to Proven Reserves during the period such hedge arrangement is in effect.

On September 11, 2009, we entered into two fixed price commodity swap contracts with Natixis as our counterparty, which is one of our senior lenders under the ARCA. The fixed price swaps were based on West Texas Intermediate NYMEX prices and are summarized in the table below.

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Time Period		Fixed Oil Price	Barrels Per Day
4/1/11 - 12/31/11	$	75.90	700
1/1/12 - 12/31/12	$	77.25	700

On August 22, 2011, we executed a mutual termination letter with Natixis providing for the termination of the two fixed price swaps. In connection with the termination of the commodity swap transactions, we must pay $3.65 million to Natixis. This amount has become a senior obligation of the Company in addition to amounts owed under the ARCA.

On August 10, 2010, we sold certain natural gas commodity derivative contracts realizing net proceeds of $0.8 million pursuant to the Forbearance Agreements.

In the past, we maintained collar commodity derivative contracts with UBNA as our counterparty. UBNA is one of the senior lenders under the ARCA. These derivative contracts have expired. They were as follows:

Time Period		Floor Oil Price		Ceiling Oil Price	Barrels Per Day		Floor Gas Price		Ceiling Gas Price	Mcf per Day	Barrels of Equivalent Oil per Day(a)
7/1/10 - 12/31/10	$	80.00	$	108.20	333	$	7.75	$	9.85	1,567(b)	594
7/1/10 - 12/31/10	$	85.00	$	101.50	233	$	8.00	$	9.40	1,033	406
1/1/11 - 3/31/11	$	80.00	$	107.30	333	$	7.75	$	11.60	1,467(b)	578
1/1/11 - 3/31/11	$	85.00	$	100.50	200	$	8.00	$	11.05	967	361

(a) This column is computed by dividing the Mcf per Day by 6 and adding it to Barrels per Day.

(b) On August 10, 2010, we sold certain natural gas commodity derivative contracts realizing net proceeds of $0.8 million pursuant to the Forbearance Agreement.

During October 2008, we sold certain uncovered floor price commodity derivative contracts for the period July 2010 to December 2010 for $0.6 million to our counterparty and realized a gain of $0.1 million. During November 2008, we sold all remaining uncovered floor price commodity derivative contracts for the period November 2008 through June 2010 for $2.6 million to our counterparty and realized a gain of $0.6 million.

Interest Rate Swap Agreement

On January 12, 2009, we entered into a three-year LIBOR interest rate basis swap contract with Natixis Financial Products, Inc. (Natixis FPI) for $20.0 million in notional exposure. We entered into the interest rate swap agreement to partially mitigate the risk associated with rising interest rates. Under the terms of the transaction, we were required to pay Natixis FPI, in three-month intervals, a fixed rate of 1.73% and Natixis FPI was required to pay Cano the prevailing three-month LIBOR rate.

On September 9, 2011, we executed a mutual termination letter with Natixis FPI providing for the termination of the interest rate swap agreement. In connection with the termination of the interest rate swap, we must pay $145,500 to Natixis. This amount has become a senior obligation of the Company in addition to amounts owed under the ARCA.

Financial Statement Impact

During the years ended June 30, 2011, 2010 and 2009, respectively, the gain (loss) on derivatives reported in our consolidated statements of operations is summarized as follows:

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	Location of Gain (Loss) Derivative	Year Ended June 30, 2011	2010	2009
Settlements received/accrued on commodity derivatives	Other income (expense)	$ 1,652	$ 4,940	$ 6,840
Settlements received sale contracts on commodity derivatives	Other income (expense)	800		653
Settlements paid/accrued on commodity derivatives	Other income (expense)			(550)
Settlements paid/accrued on interest rate swap	Other income (expense)	(1,970)	(274)	(53)
Realized gain (loss) on derivatives	Other income (expense)	482	4,666	6,890
Unrealized gain (loss) on commodity derivatives	Other income (expense)	(9,384)	(6,274)	36,849
Unrealized gain (loss) on interest rate swap	Other income (expense)	66	(317)	51
Gain (loss) on derivatives	Other income (expense)	$ (8,836)	$ (1,925)	$ 43,790

The realized gain (loss) on derivatives consists of actual cash settlements under our commodity collars and interest rate swap derivatives during the respective periods, and the sale of floor price commodity derivative contracts during October and November 2008.

The cash settlements received/accrued by us under commodity derivatives were cumulative monthly payments due to us since the NYMEX natural gas and crude oil prices were lower than the floor prices or swap prices set for the respective time periods plus realized gains from the sale of commodity derivative contracts as previously discussed.

The cash settlements paid/accrued by us under commodity derivatives were cumulative monthly payments due to our counterparty since the NYMEX crude oil and natural gas prices were higher than the ceiling prices or swap prices set for the respective time periods.

The cash settlements paid/accrued by us under the interest rate swap were quarterly payments to our counterparty since the actual three-month LIBOR interest rate was lower than the fixed 1.73% rate we pay to the counterparty.

The cash flows relating to the derivative instrument settlements that are due, but not cash settled are reflected in operating activities on our consolidated statements of cash flows as changes to current liabilities. At June 30, 2011, we had no amounts receivable from our counterparty included in accounts receivable on our consolidated balance sheet. June 30, 2010, we had recorded a $0.3 million receivable from our counterparty included in accounts receivable on our consolidated balance sheet. At June 30, 2009, we had recorded a $0.6 million receivable from our counterparty included in accounts receivable on our consolidated balance sheet.

The unrealized gain (loss) on commodity derivatives represents estimated future settlements under our commodity derivatives and is based on mark-to-market valuation based on assumptions of forward prices, volatility and the time value of money as discussed below. We compared our internally derived valuation to our counterparties independently derived valuation to further validate our mark-to-market valuation.

The unrealized gain (loss) on interest rate swap represents estimated future settlements under our interest rate swap agreement and is based on a mark-to-market valuation based on assumptions of interest rates, volatility and the time value of money as discussed below.

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Fair Value Measurements

Our assets and liabilities recorded at fair value are categorized based upon the level of judgment associated with the inputs used to measure their fair value. A fair value hierarchy has been established that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). We classify fair value balances based on the observability of those inputs. The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices in active markets for identical assets or liabilities that we have the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 Inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable. These inputs are either directly observable in the marketplace or indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured.

Level 3 Inputs reflect management s best estimate of what market participants would use in pricing the asset or liability at the measurement date. Consideration is given to the risk inherent in the valuation technique and the risk inherent in the inputs to the model.

In valuing certain contracts, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. For disclosure purposes, assets and liabilities are classified in their entirety in the fair value hierarchy level based on the lowest level of input that is significant to the overall fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels.

The fair value of our derivative contracts are measured using Level 2 and Level 3 inputs. The Level 3 input pertained to the subjective valuation for the effect of our own credit risk, which was significant to the fair value of the crude oil swap derivative contracts. The fair value of our commodity derivative contracts and interest rate swap are measured using Level 2 inputs based on the hierarchies previously discussed.

The estimated fair value of derivatives included in the consolidated balance sheet at June 30, 2011 is summarized below.

In thousands		
Derivative liability (Level 2)		
Interest rate swap current		(198)
Interest rate swap noncurrent		
Derivative liability (Level 3)		
Crude oil swap current		(5,095)
Crude oil swap noncurrent		(2,602)
Net derivative liabilities	$	(7,895)

The following table shows the reconciliation of changes in the fair value of the net derivative assets classified as Level 2 and 3, respectively, in the fair value hierarchy for the year ended June 30, 2011.

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In thousands		Total Net Derivative Assets (Liabilities)
Balance at June 30, 2010	$	1,191
Unrealized loss on derivatives		(9,318)
Settlements, net		232
Balance at June 30, 2011	$	(7,895)

The change from net derivative assets of $1.2 million at June 30, 2010 to net derivative liabilities of $7.8 million at June 30, 2011 is attributable primarily to the increases in crude oil and natural gas futures prices. These amounts are based on our mark-to-market valuation of these derivatives at June 30, 2011 and may not be indicative of actual future cash settlements.

The following table summarizes the fair value of our derivative contracts as of the dates indicated:

	Asset Derivatives						Liability Derivatives					
	June 30, 2011			June 30, 2010			June 30, 2011			June 30, 2010		
In thousands	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value
Derivatives not designated as hedging instruments												
Commodity derivative contracts	Derivatives current	$		Derivatives current	$	2,968	Derivatives current	$	(5,095)	Derivatives current	$	(206)
Commodity derivative contracts	Derivatives noncurrent			Derivatives noncurrent			Derivatives noncurrent		(2,602)	Derivatives noncurrent		(1,308)
Interest rate swaps	Derivatives current			Derivatives current			Derivatives current		(198)	Derivatives current		(204)
Interest rate swaps	Derivatives noncurrent			Derivatives noncurrent			Derivatives - noncurrent			Derivatives - noncurrent		(60)
Total derivatives not designated as hedging instruments		$			$	2,968		$	(7,895)		$	(1,778)
Total derivatives designated as hedging instruments		$			$			$			$	
Total derivatives		$			$	2,968		$	(7,895)		$	(1,778)

7. DISCONTINUED OPERATIONS

We had no Discontinued Operations for the year ended June 30, 2011.

On October 1, 2008, we completed the sale of our wholly-owned subsidiary, Pantwist, LLC, for a net purchase price of $40.0 million consisting of a $42.7 million purchase price adjusted for $2.1 million of net cash received from discontinued operations during the three months ended September 30, 2008 and $0.6 million of advisory fees. The sale had an effective date of July 1, 2008.

On December 2, 2008, we completed the sale of our Corsicana oil and gas properties (the Corsicana Properties) for $0.3 million. In the three-month period ended September 30, 2008, we recorded a $3.5 million ($2.3 million after-tax) impairment of the Corsicana Properties, as we determined that we would not be developing its estimated proved undeveloped reserves within the next five years.

On January 27, 2010, we completed the sale of our interests in certain oil and gas properties located in the Texas Panhandle (Certain Panhandle Properties) for net proceeds of $6.2 million, subject to customary post-closing adjustments. The sale had an effective date of January 1, 2010.

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The operating results of Pantwist, LLC, the Corsicana Properties and the Certain Panhandle Properties for the years ended June 30, 2011, 2010, and 2009 have been reclassified to discontinued operations in the consolidated statements of operations as detailed in the table below (in thousands).

	For the Year Ended June 30,		
	2011	**2010**	**2009**
Operating Revenues:			
Crude oil sales		$ 35	$ 1,388
Natural gas sales		972	3,666
Total operating revenues		1,007	5,054
Operating Expenses:			
Lease operating		178	945
Production and ad valorem taxes		117	438
Impairment of long-lived assets			3,516
Depletion and depreciation		27	69
Accretion of discount on asset retirement obligations		2	5
Interest expense, net		43	97
Total operating expenses		367	5,070
Gain (loss) on sale of properties		2,591	19,246
Income before income taxes		3,231	19,230
Income tax provision		(1,174)	(6,912)
Income from discontinued operations		$ 2,057	$ 12,318

Interest expense, net of interest income, was allocated to discontinued operations based on the percent of operating revenues applicable to discontinued operations to the total operating revenues.

At June 30, 2009, on our consolidated balance sheet, the assets relating to the Certain Panhandle Properties are classified as assets held for sale and the liabilities are classified as liabilities associated with discontinued operations.

8. COSTS INCURRED FOR DRILLING AND EQUIPPING EXPLORATORY WELLS USING SECONDARY AND TERTIARY TECHNOLOGY

As part of the Company s historical strategy, it incurred costs associated with secondary and tertiary techniques that involve drilling and equipping exploratory wells. This occurred within reservoirs for which the Company already had estimated proved developed reserves recorded from existing primary or secondary development; however, there were no estimated proved reserves for subsequent secondary or tertiary activities. Secondary and tertiary costs for drilling and equipping wells include converting primary production wells to injection wells, installation of injection facilities, and injecting materials. When conducting secondary and tertiary drilling and equipping activities, the Company deferred drilling and equipping costs associated with these exploratory wells pending a determination of whether proved reserves are found. If proved reserves were not found, all of the costs associated with the project were recorded as exploration expense in the period in which such determination was made. If proved reserves were found, the drilling and equipping costs incurred in the project were added to the depletion base and depreciated using the units of production method based over the production life of the associated proved developed reserves.

Secondary and tertiary projects typically take longer to complete than drilling primary production wells, and as a result, the period during which exploratory drilling costs are deferred is longer. Our secondary and tertiary projects were evaluated to determine whether they have found proved reserves when the projects were substantially complete. The Company considered a secondary or tertiary project to be substantially complete when the amount of material injected reaches its target pore volume injection (PVI) percentage determined necessary to stimulate response. This applied to two projects - the Duke

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Sand waterflood at the Desdemona Properties (Duke Sands Waterflood) and the ASP chemical injection pilot project at the Nowata Properties (Nowata ASP Project). These two projects are updated as follows.

Duke Sand Waterflood. The primary source of water for this waterflood project was derived from our Barnett Shale production. During July 2009, the Company shut-in the Barnett Shale natural gas production due to uneconomic natural gas commodity prices; therefore, it no longer had an economic source of water to continue flooding the Duke Sand. This reduced the rate of water injection to a point where the Company could not consider the waterflood active. The Company recorded exploration expense of $11.4 million for the year ended June 30, 2009.

Nowata ASP Project. December 2009, the Company finalized its performance analysis, which indicated the Nowata ASP Project did not result in significantly increased oil production quantities and was therefore considered not economically viable. Accordingly, at December 31, 2009, Cano recorded a $5.0 million pre-tax exploration expense.

For the years ended June 30, 2011, 2010, and 2009, we did not incur geological and geophysical expenses or delay rentals associated with exploration projects.

The table below summarizes the drilling and equipping costs incurred and deferred related to secondary and tertiary projects that were pending the determination of whether proved reserves have been found.

In Thousands		**2011**		**As of June 30, 2010**		**2009**
Secondary Duke Sand	$		$		$	
Tertiary Nowata ASP Pilot						4,849
Total Costs	$		$		$	4,849

The following table provides an aging of deferred exploratory well costs based on the date the project was initiated (prior to determination of success).

In Thousands	**2011**	**As of June 30, 2010**		**2009**
Capitalized exploratory well costs that have been capitalized period of one year or less			$	1,633
Capitalized exploratory well costs that have been capitalized period of one to three years				3,216
Balance at June 30			$	4,849
Number of projects that have exploratory well costs that have been capitalized for a period of one to three years				1

The following table reflects the net change in deferred exploratory project costs:

	Years ended June 30,		
In Thousands	2011	2010	2009
Balance at July 1		$ 4,849	$ 13,073
Additions pending the determination of proved reserves		175	3,155
Deferred exploratory well costs charged to expense		(5,024)	(11,379)
Balance at June 30			$ 4,849

9. STOCK OPTIONS

Our 2005 Long-Term Incentive Plan (the 2005 LTIP), as approved by our stockholders, authorized the issuance of up to 3,500,000 shares of our common stock to key employees, consultants and

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outside directors of our company and subsidiaries. The 2005 LTIP stipulates that for any calendar year (i) the maximum number of stock options or stock appreciation rights that any Executive Officer (as defined in the Plan) can receive is 300,000 shares of common stock, (ii) the maximum number of shares relating to restricted stock, restricted stock units, performance awards or other awards that are subject to the attainment of performance goals that any Executive Officer can receive is 300,000 shares of common stock; and (iii) the maximum number of shares relating to all awards that an Executive Officer can receive is 300,000 shares. The 2005 LTIP permits the grant of incentive stock options, non-qualified stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards, dividend equivalent rights and other awards, whether granted singly, in combination or in tandem. The 2005 LTIP terminates on December 7, 2015; however, awards granted before that date would continue to be effective in accordance with their terms and conditions.

Stock option awards are generally granted with an exercise price equal to our market price at the date of grant and have 10-year contractual terms. Stock option awards to employees generally vest over three years of continuous service. Stock option awards to directors generally vest immediately or in one year. On June 28, 2007, we resolved that upon the resignation of any current member of the Board of Directors who is in good standing on the date of resignation, such member s unvested stock options shall be vested and shall have the exercise period for all options extended to twenty-four months after the date of resignation. The grant-date fair value of director options for which vesting was accelerated during the year ended June 30, 2008 amounted to approximately $31,000. Such amount is included in general and administrative expense on our consolidated statements of operations. There were no options for which vesting was accelerated during the years ended June 30, 2011, 2010, or 2009.

A summary of options we granted during the years ended June 30, 2011, 2010, and 2009 are as follows:

	Shares		Weighted Average Exercise Price
Outstanding at July 1, 2008	1,084,051	$	5.71
Options granted	577,900	$	1.87
Options forfeited or expired	(261,949)	$	3.93
Options exercised			
Outstanding at June 30, 2009	1,400,002	$	4.42
Options granted	16,032	$	1.03
Options forfeited or expired	(100,474)	$	5.24
Options exercised	(4,850)	$	0.43
Outstanding at June 30, 2010	1,310,710	$	4.33
Options granted			
Options forfeited or expired	(229,580)	$	3.96
Options exercised	(9,500)	$	0.43
Outstanding at June 30, 2011	1,071,630	$	4.45

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The following is a summary of stock options outstanding at June 30, 2011:

Exercise Price		Options Outstanding	Remaining Contractual Lives (Years)	Options Exercisable
$	0.43	201,899	7.41	201,899
$	0.60	2,600	7.37	1,734
$	0.70			
$	1.03	16,032	8.39	16,032
$	3.19	2,600	7.20	1,734
$	3.27			
$	3.98	81,949	7.08	76,851
$	4.00	50,000	3.47	50,000
$	4.13	25,000	3.76	25,000
$	4.73	61,803	5.77	61,803
$	5.15	78,685	4.98	78,685
$	5.42	240,000	5.50	240,000
$	5.75	104,900	6.65	104,900
$	5.95			
$	6.15	24,200	6.01	24,200
$	6.30	50,000	4.46	50,000
$	7.25	125,000	6.46	125,000
$	7.47	6,962	6.42	6.962
$	4.45	1,071,630	6.07	1,064,800

Based on our $0.33 stock price at June 30, 2011, the intrinsic value of both the options outstanding and exercisable options was nil.

Total options exercisable at June 30, 2011, amounted to 1,064,800 shares and had a weighted average exercise price of $4.45. Upon exercise, we issue the full amount of shares exercisable pursuant to the terms of the options from new shares. We have no plans to repurchase those shares in the future.

The following is a summary of options exercisable at June 30, 2011, 2010, and 2009:

	Shares		Weighted Average Exercise Price
June 30, 2011	1,064,800	$	4.45
June 30, 2010	1,142,995	$	4.19
June 30, 2009	943,420	$	4.46

The fair value of each stock option is estimated on the date of grant using the Black-Scholes option-pricing model. Expected volatilities are based on historical volatility of our common stock. We use historical data to estimate option exercise and employee termination within the valuation model. The expected lives of options granted represent the period of time that options granted are estimated to be outstanding. The risk-free interest rate for periods within the contractual life of the option is based on the five-year U.S. Treasury yield curve in effect at the time of the respective grant. The expected dividend yield reflects our intent not to pay dividends on our common stock during the contractual periods.

The factors used to calculate the fair values of those options are summarized in the table below:

	Years Ended June 30,		
	2011	2010	2009
No. of shares		16,032	577,900
Risk free interest rate		2.19%	2.15-3.39%
Expected life		5 years	5 years
Expected volatility		98.9%	56.3-90.1%
Expected dividend yield		0%	0%
Weighted average grant date fair value exercise prices equal to market value on grant date		$ 0.77	$ 0.99

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For the years ended June 30, 2011, 2010, and 2009, we have recorded a charge to stock compensation expense of $0, $0.2 million, and $0.7 million, respectively, for the estimated fair value of the options granted to our directors and employees. As of June 30, 2011, total compensation cost related to non-vested option awards not yet recognized was insignificant.

10. DEFERRED COMPENSATION

We have granted share awards to key employees from our 2005 LTIP, previously discussed in Note 9. On July 2, 2007, we granted our executive officers share awards for services provided during the year ended June 30, 2007 totaling 395,000 shares vesting in three equal amounts on the first, second and third anniversaries of July 2, 2007.

On May 12, 2008, we granted our executive officers share awards for services provided during the year ended June 30, 2008 totaling 460,000 shares vesting in three equal amounts on the first, second and third anniversaries of May 12, 2008. On June 23, 2008, in connection with his hiring, we granted an executive officer share awards totaling 100,000 shares vesting in three equal amounts on the first, second and third anniversaries of June 23, 2008.

As of June 30, 2011, we had no non-vested share awards. A summary of non-vested share awards for the three years ended June 30, 2011, 2010, and 2009 is as follows:

	Shares	**Weighted Average Grant-Date Fair Value**	**Fair Value $000s**
Non-vested share awards at July 1, 2008	1,005,000	6.80	6,833
Shares granted			
Shares vested	(394,376)	6.61	(2,605)
Shares forfeited and surrendered	(130,623)	6.76	(884)
Non-vested share awards at June 30, 2009	480,001	6.97	3,344
Shares granted			
Shares vested	(239,999)	6.97	(1,672)
Shares forfeited and surrendered	(78,334)	6.53	(512)
Non-vested share awards at June 30, 2010	161,668	$ 7.18	$ 1,160
Shares granted			
Shares vested	(50,453)	6.11	(308)
Shares forfeited and surrendered	(111,215)	7.66	(852)
Non-vested share awards at June 30, 2011			

The fair values of the awards are based on our actual stock price on the date of grant multiplied by the number of shares granted. As of June 30, 2011, there were no non-vested shares.

For the 2011 Fiscal Year, we recorded a credit to stock-based compensation expense of $0.6 million, primarily due to award forfeitures. The forfeitures resulted from shares used to satisfy employees   tax withholding obligations related to the vesting of their share awards and employee termination.

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11. RELATED PARTY TRANSACTIONS

S. Jeffrey Johnson, our former Chief Executive Officer and Chairman of our board of directors, owns approximately 3.7% of our outstanding Preferred Stock. For the years ended June 30, 2011, 2010, and 2009, we paid preferred dividend payments to Mr. Johnson of approximately nil, $79,000, and $20,000, respectively

Pursuant to an agreement dated December 16, 2004, as amended, we agreed with R.C. Boyd Enterprises, a Delaware corporation, to become the lead sponsor of a television production called Honey Hole (Honey Hole Production). As part of our sponsorship, we provided fishing and outdoor opportunities for children with cancer, children from abusive family situations and children of military veterans. We were entitled to receive two thirty-second commercials during all broadcasts of the Honey Hole Production and received opening and closing credits on each episode. Randall Boyd is the sole shareholder of R.C. Boyd Enterprises and was a member of our Board of Directors. Pursuant to an agreement dated as of December 5, 2007, as of December 31, 2008, we are no longer a Honey Hole Production sponsor. We paid no money to R.C. Boyd Enterprises after December 31, 2008. During the year ended June 30, 2009, we paid $75,000 for sponsorship activities.

12. IMPAIRMENT OF LONG-LIVED ASSETS AND GOODWILL

During the 2011 Fiscal Year, we recorded impairment of $172.9 million related to our reduction of estimated PUD and estimated PDNP reserves in accordance with the SEC s final rule, *Modernization of Oil and Gas Reporting,* issued in December 2008 and effective for annual reports on Form 10-K for years ending on or after December 31, 2009, which amended Rule 4-10 of Regulation S-X (the Final Rule). Among other things, guidance for the Final Rule for the reporting of estimated proved undeveloped requires that a company must have adopted a development plan and have made a final investment decision for their development. The mere intent to develop is not sufficient for reporting estimated proved undeveloped reserves. For all estimated reserves, the Final Rule requires that there must exist, or there must be a reasonable expectation that there will exist, the financing required to implement the development projects. The capital requirement for development of the estimated PUD and estimated PDNP reserves previously reported by the Company as of June 30, 2010, was estimated to be approximately $303.5 million, and approximately $7.0 million, respectively. Due to the Company s current financial constraints, including continued losses, defaults under our loan agreements and our Series D Preferred Stock, no available borrowing capacity, constrained cash flow, negative working capital, and limited to no other capital availability, there is not a reasonable expectation that the Company can obtain the financing required to implement these projects within a reasonable time, even though we believe these projects, in and of themselves, remain technically feasible and economically attractive. Therefore, we have recorded the aforementioned impairment to our oil and gas properties.

We estimated the impairment charge as the difference between the net carrying values of the properties on which impairment indicators exist and their respective fair values. We estimated the fair value of the properties on which impairment indicators were present as the present value of future cash flows from each property s estimated proved reserves based on future oil and gas prices in effect as of June 30, 2011, discounted at 10% per annum. The carrying values of our properties in the Desdemona, Panhandle, and Cato fields were greater than the estimated future net cash flows associated with the proved reserves in those fields, and in our judgment, impairment of those fields was indicated. The fair value of oil and gas properties impaired represents a level 3 fair value measurement because the cash flows associated with future oil and natural gas production is based on unobservable market inputs such as future production rates, future commodity prices, future production costs, and our assumption that the discounted cash flows associated with such measures is a reasonable representation of the fair values of those properties.

During the 2010 Fiscal Year, we wrote down $0.3 million of costs associated with the ASP facility used for the Nowata ASP Project. The facility s water filtering process did not work properly with the oil-water fluid production at our Nowata Properties. During the 2009 Fiscal Year, we recorded a $26.7 million impairment on our Barnett Shale Properties as the decline in commodity prices created an uncertainty about the likelihood of developing our reserves associated with our Barnett Shale natural gas properties within the

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next five years. Therefore, during the quarter ended December 31, 2008, we recorded a $22.4 million pre-tax impairment to our Barnett Shale Properties. During the quarter ended June 30, 2009, we recorded an additional $4.3 million pre-tax impairment to our Barnett Shale Properties as the forward outlook for natural gas prices continued to decline and we shut-in our Barnett Shale natural gas wells. The fair value was determined using estimates of future production volumes, prices and operating expenses, discounted to a present value.

The fair values for our assets were determined using estimates of future net cash flows, discounted to a present value, which are considered Level 3 inputs as previously discussed in Note 6.

13. ASSET RETIREMENT OBLIGATION

Our asset retirement obligation (ARO) primarily represents the estimated present value of the amount we will incur to plug and abandon our producing properties at the end of their productive lives, in accordance with applicable state laws. We determine our ARO by calculating the present value of estimated cash flows related to the liability. At June 30, 2011, our liability for ARO was $4.7 million, of which $4.5 million was considered long term. At June 30, 2010, our liability for ARO was $3.2 million, of which $3.0 million was considered long term. At June 30, 2009, our liability for ARO was $2.9 million, of which $2.8 was considered long term. Our ARO is recorded as current or non-current liabilities based on the estimated timing of the related cash flows.

The valuation technique we utilize to determine the fair value of the liability at inception applies a credit-adjusted risk-free rate, which takes into account our credit risk, the time value of money, and the current economic state, to the undiscounted expected plugging and abandonment cash flows. Given the unobservable nature of certain inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs, as previously discussed in Note 6.

The following table describes the changes in our ARO for the years ended June 30, 2011, and 2010 (in thousands):

Asset retirement obligation at July 1, 2009	$	2,871
Accretion of discount		287
Change in estimate		336
Liabilities incurred for properties acquired and drilled		
Sale of oil and gas properties		
Liabilities settled, net		(314)
Asset retirement obligation at June 30, 2010		3,180
Accretion of discount		338
Change in estimate		1,180
Liabilities settled, net		(3)
Asset retirement obligation at June 30, 2011	$	4,695

For the year ended June 30, 2011, the change in estimate of our ARO liability resulted primarily from The shortening of life from 49 years to 5 years for the Desdemona field, following the reserve report issued for 2011 FY. For the year ended June 30, 2009, the change in estimate of our ARO liability resulted primarily from a change in estimated timing to plug and abandon wells.

14. INCOME TAXES

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax provisions. Our income tax expense (benefit) is as follows:

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In Thousands	Years Ended June 30, 2011	2010	2009
Current income tax expense (benefit)			
Federal	$	$	$
State			(61)
Total current tax expense (benefit)			(61)
Deferred income tax benefit			
Federal	(17,889)	(6,423)	(5,423)
State	(1,086)	(39)	301
Total deferred tax benefit	(18,975)	(6,462)	(5,122)
Total income tax benefit	$ (18,975)	$ (6,462)	$ (5,183)

A reconciliation of the differences between our applicable statutory tax rate and our effective income tax rate for the years ended June 30, 2011, 2010, and 2009 is as follows:

In Thousands, except %	Years Ended June 30, 2011	2010	2009
Rate	35%	35%	35%
Tax at statutory rate	$ (71,637)	$ (7,043)	$ (6,206)
State taxes	(3,041)	(179)	240
Increase (decrease) resulting from:			
Change in state rate		140	
Permanent and other	28	101	64
Differences in share-based compensation expense	104	519	472
Change in valuation allowance	55,571		
Goodwill impairment			247
Income tax benefit	$ (18,975)	$ (6,462)	$ (5,183)

A schedule showing the significant components of the net deferred tax liability as of June 30, 2011, and 2010 are as follows:

In Thousands	As of June 30, 2011	2010
Current		
Deferred tax assets:		
Merger costs	$ 0	$ 540
Unrealized loss on commodity derivatives	1,934	
Other	1,170	413
Total current deferred tax assets	3,104	953
Deferred tax liabilities:		
Unrealized gain on commodity derivatives		(936)
Total current deferred tax liabilities		(936)
Less valuation allowance	(3,104)	
Net current deferred tax asset	$ 0	$ 17
Long-Term		
Deferred tax assets:		
Difference in book and tax bases of oil and gas properties	$ 6,340	$
Deferred compensation expense	1,779	2,108
Net operating loss carryovers	43,133	30,641

Unrealized loss on commodity derivatives		973		438
Other		1,012		341
		53,237		33,528
Less: valuation allowance		(53,237)		(770)
Total long-term deferred tax assets				32,758
Deferred tax liabilities:				
Difference in book and tax bases of oil and gas properties				(51,750)
Unrealized gain on commodity derivatives				
Total long-term deferred tax liabilities				(51,750)
Net long-term deferred tax liability	$		$	(18,992)

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At June 30, 2011, and 2010, we had net operating loss (NOL) carry-forwards for tax purposes of approximately \$119.2 million and \$84.6 million, respectively. The net operating losses principally expire between 2024 and 2030. A total of \$2.2 million of these NOL carry-forwards will be unavailable to offset any future taxable income due to limitations from change in ownership, which occurred at our merger in May 2004, as defined in Section 382 of the Internal Revenue Service code. As such, we have previously established a valuation allowance on deferred tax assets of \$770,000 at June 30, 2010. Further, based on our continued net losses and our judgment about the Company s ability to generate taxable income in future years, we have established a valuation allowance on deferred tax assets of \$56,341,000 at June 30, 2011.

15. COMMITMENTS AND CONTINGENCIES

Our operations are subject to a variety of risks and disputes normally incident to our business. As a result, we are and may, at any given time, be a defendant in various legal proceedings and litigation arising in the ordinary course of business. We maintain insurance policies with insurers in amounts and with coverage and deductibles that we, with the advice of our insurance advisors and brokers, believe are reasonable and prudent. We cannot, however, assure you that this insurance will be adequate to protect us from all material expenses related to current and potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

Resaca Claim

Section 7.6 of the Merger Agreement with Resaca Exploitation, Inc. (Resaca) provided for the Company and Resaca to share transaction expenses related to the printing, filing and mailing of the registration statement on Form S-4 covering the Resaca shares that would have been issued to Cano stockholders in the merger, the proxy statements relating to the meetings at which the stockholders of Cano and Resaca voted to approve the merger, and the solicitation of stockholder approvals. On September 2, 2010, we filed an action against Resaca in the Tarrant County District Court seeking a declaratory judgment to clarify the scope and determine the amount of any expenses that are reimbursable under Section 7.6 of the Merger Agreement. On December 16, 2010, the presiding District Court judge denied Resaca s request to transfer the venue. On January 19, 2011, Resaca filed a motion for Partial Summary Judgment to seek reimbursement of certain merger-related expenses totaling \$1.1 million, for which Cano s 50% portion would be \$0.5 million. On April 14, 2011, the presiding judge denied Resaca s request for Partial Summary Judgment. Mediation on July 13, 2011, did not resolve differences. Based on our knowledge and judgment of the facts as of October 20, 2011, our financial statements dated June 30, 2011, present fairly the effect of the actual and the anticipated future costs to resolve this matter.

Greenhaw Litigation

On August 14, 2009, Chimo Properties, Ltd. and Morris R. Greenhaw sued Square One Energy, Inc., our subsidiary, in the 91st District Court Eastland County, Texas, alleging that Square One Energy, Inc. conducted its oil and gas operations negligently, resulting in surface damages to the plaintiffs ranch. The plaintiffs are seeking money damages of approximately \$1.6 million. We have been vigorously defending, and will continue to vigorously defend, against plaintiffs claims. A memorandum of settlement has been signed and a final settlement is being negotiated. Based on our knowledge and judgment of the facts as of October 20, 2011, our financial statements dated June 30, 2011, present fairly the effect of the actual and the anticipated future costs to resolve this matter.

Johnson Wage Claim

On August 19, 2011, Jeffrey Johnson, our former Chief Executive Officer, filed an administrative wage claim against us with the Texas Workforce Commission (TWC). In the claim, Johnson requested $643,574.06 in (1) unpaid severance and car allowance payments allegedly due under his employment agreement, (2) payment for accrued unused vacation since 2006 allegedly due under his employment agreement, (3) unpaid health care coverage premiums for six months allegedly due under his employment agreement, and (4) statutory interest. We filed a response to the TWC on September 19, 2011 that disputed the amount of the wage claim above what was due under the terms of Mr. Johnson s employment agreement in connection with the termination of his employment without cause and requested an offset for

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alleged personal charges on Mr. Johnson s company credit card. On September 22, 2011, the TWC issued a Preliminary Wage Determination Order (PWDO) that Mr. Johnson is entitled to $329,427.04 (consisting of $312,067.99 in unpaid severance pay and $17,359.05 in unpaid vacation pay). The deadline for either party to appeal the PWDO to the TWC s Special Hearings Department was October 13, 2011. We did not file an appeal. If Johnson has not filed an appeal, the TWC advises that the PWDO will become final on October 23, 2011 will be eligible for collection at that time. Based on our knowledge and judgment of the facts as of October 20, 2011, our financial statements dated June 30, 2011, present fairly the effect of the actual and the anticipated future costs to resolve this matter.

Other

Occasionally, we are involved in other various claims and lawsuits and certain governmental proceedings arising in the ordinary course of business. Our management does not believe that the ultimate resolution of any current matters that are not set forth above will have a material effect on our financial position or results of operations. Management s position is supported, in part, by the existence of insurance coverage, indemnification and escrow accounts. None of our directors, officers or affiliates, owners of record or beneficial owners of more than five percent of any class of our voting securities, or security holder is involved in a proceeding adverse to us or our subsidiaries or has a material interest adverse to our subsidiaries or us.

Environmental

To date, our expenditures to comply with environmental or safety regulations have not been significant and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

Leases

Effective November 17, 2010, we entered into a non-cancelable operating lease for our principal executive offices in Irving, Texas. The lease expires on March 31, 2016. We have also contracted for various equipment rentals at our field locations. Our remaining obligation for the life of our operating leases is approximately $0.7 million. Future minimum rentals due under our non-cancellable operating leases were as follows on June 30, 2011 for the following fiscal years:

In Thousands	**2012**	**2013**	**2014**	**2015**	**2016**	**Total**
Total operating lease obligations	$ 135	$ 141	$ 145	$ 150	$ 115	$ 686

Rent expense amounted to $0.7 million, $0.7 million, and $0.3 million for the years ended June 30, 2011, 2010, and 2009, respectively.

Employment Contracts

We have no employment contracts with our executives.

16. SUBSEQUENT EVENTS (UNAUDITED)

- On August 19, 2011, Jeffrey Johnson, our former Chief Executive Officer, filed an administrative wage claim against us with the Texas Workforce Commission (TWC). In the claim, Johnson requested $643,574.06 in (1) unpaid severance and car allowance payments allegedly due under his employment agreement, (2) payment for accrued unused vacation since 2006 allegedly due under his employment agreement, (3) unpaid health care coverage premiums for six months allegedly due under his employment agreement, and (4) statutory interest. We filed a response to the TWC on September 19, 2011 that disputed the

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amount of the wage claim above what was due under the terms of Mr. Johnson s employment agreement in connection with the termination of his employment without cause and requested an offset for alleged personal charges on Mr. Johnson s company credit card. On September 22, 2011, the TWC issued a Preliminary Wage Determination Order (PWDO) that Mr. Johnson is entitled to $329,427.04 (consisting of $312,067.99 in unpaid severance pay and $17,359.05 in unpaid vacation pay). The deadline for either party to appeal the PWDO to the TWC s Special Hearings Department was October 13, 2011. We did not file an appeal. If Johnson has not filed an appeal, the TWC advises that the PWDO will become final on October 23, 2011 will be eligible for collection at that time. Based on our knowledge and judgment of the facts as of October 20, 2011, our financial statements dated June 30, 2011, present fairly the effect of the actual and the anticipated future costs to resolve this matter.

• On August 22, 2011, our commodity hedges with the lenders were terminated at a cost of $3.65 million. This amount has become a senior obligation of the Company in addition to the amounts owed under the ARCA.

• On August 31, 2011, we failed to make a required payment of interest under the ARCA. Our failure to make such payment of interest constituted an Event of Default under the ARCA and the SCA, for which the lenders under such credit agreements may terminate their obligation to extend credit to us and declare all amounts payable under the ARCA and the SCA due and payable in full. We have not received any notice from the lenders with respect to the exercise of their respective rights, including any right to accelerate the amounts payable by us. We continue to work with our lenders and advisors as we consider strategic alternatives.

• On September 6, 2011, we were not able to redeem the outstanding Preferred Stock as required, due to the ongoing defaults under the ARCA.

• On September 9, 2011, our interest rate hedge with the lenders was terminated at a cost of $145,500. This amount has become a senior obligation of the Company in addition to the amounts owed under the ARCA.

• On September 12, 2011, we received notice from the agent for the ARCA that the outstanding Libor based loan advances under the ARCA will be converted to prime based advances as they mature.

• For the period from September 16 through September 30, 2011, the Bureau of Land Management issued an order suspending operations at the Cato Properties until we could establish to the Bureau s satisfaction that we are substantially in compliance with the Bureau s operating and environmental guidelines. Effective October 1, 2011, the Cato Properties were returned to production.

• On September 23, 2011, our lenders delivered Reservation of Rights Letters.

• On August 14, 2009, Chimo Properties, Ltd. and Morris R. Greenhaw sued Square One Energy, Inc., our subsidiary, in the 91st District Court Eastland County, Texas, alleging that Square One Energy, Inc. conducted its oil and gas operations negligently, resulting in surface damages to the plaintiffs ranch. The plaintiffs are seeking money damages of approximately $1.6 million. This trial for this case is set to commence on October 14, 2011. We have been vigorously defending, and will continue to vigorously defend, against plaintiffs claims. Based on our knowledge and judgment of the facts as of October 20, 2011, our financial statements dated June 30, 2011, present fairly the effect of the actual and the anticipated future costs to resolve this matter.

17. SUPPLEMENTARY FINANCIAL INFORMATION FOR OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

All of our operations are directly related to oil and natural gas producing activities located in Texas, Oklahoma and New Mexico.

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Capitalized Costs Relating to Oil and Gas Producing Activities

In Thousands	June 30, 2011	2010
Mineral interests in oil and gas properties:		
Proved	$ 77,357	$ 77,357
Unproved		
Wells and related equipment and facilities	212,131	161,965
Support equipment and facilities used in oil and gas producing activities	6,072	4,031
Uncompleted wells, equipment and facilities		51,608
Total capitalized costs	295,560	294,961
Less accumulated depletion and depreciation	(235,997)	(44,615)
Net capitalized costs	$ 59,563	$ 250,346

Costs Incurred in Oil and Gas Producing Activities

In Thousands	2011	Years Ended June 30, 2010	2009
Acquisition of proved properties	$ 0	$ 2	$ 77
Acquisition of unproved properties			
Development costs	1,222	9,721	48,657
Exploration costs	0	175	2,967
Total costs incurred, net of sale of oil and gas properties	$ 1,222	$ 9,898	$ 51,701

Proved Reserves Methodology

Our estimated proved reserves, as of June 30, 2011, are made in accordance with the SEC s final rule, *Modernization of Oil and Gas Reporting,* issued in December 2008 and effective for annual reports on Form 10-K for years ending on or after December 31, 2009, which amended Rule 4-10 of Regulation S-X (the Final Rule).

The revised SEC rules include, among other things, changes to the pricing used to estimate reserves, the ability to include nontraditional resources in reserves, the use of new technology for determining reserves and permitted disclosure of probable and possible reserves. In accordance with the SEC s revised oil and gas rules, prior period reserves were not restated.

As defined by the Final Rule, proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods, and government regulations. Projects to extract the hydrocarbons must have commenced or an operator must be reasonably certain that it will commence the projects within a reasonable time. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the projects. Further requirements for assignment of estimated proved reserves include the following:

- The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas, oil, and/or water contacts, if any; and (B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons and highest known oil seen in well penetrations unless geoscience, engineering, or performance data and reliable technology

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establishes a lower or higher contact with reasonable certainty. Reliable technologies are any grouping of one or more technologies (including computational methods) that have been field-tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

- Reserves which can be produced economically through applications of improved recovery techniques (including, but not limited to fluid injections) are included in the proved classification when successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, and other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based.

- Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The prices used are the average crude oil and natural gas prices during the twelve month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. For the period ending June 30, 2011, we have computed the unweighted average first-day-of-the-month NYMEX crude oil and natural gas prices to be $90.09 per barrel and $4.21 per MMBTU, respectively. Adjusting for BTU content (including NGL content), basis differentials, marketing costs and fees, crude oil quality, and transportation costs, the average net prices realized by the Company are $84.14 per barrel and $8.48 per MCF, respectively.

Reserves engineering is a subjective process of estimating underground accumulations of crude oil, condensate, natural gas, and natural gas liquids that cannot be measured in an exact manner. The accuracy of any reserves estimate is a function of the quality of available date and of engineering and geological interpretation and judgment. The reserves actually recovered, the timing of production of those reserves, as well as operating costs and the amount and timing of development expenditures may be substantially different from original estimates. Revisions result primarily from new information obtained from development drilling, production history, field tests, and data analysis and from changes in economic factors including expectation and assumptions as to availability of financing for development projects.

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Proved Reserves

The term proved reserves is defined by the SEC in Rule 4-10(a) of Regulation S-X adopted under the Securities Act of 1933, as amended. In general, proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods, and government regulations. Prices and costs are based on those as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based on future conditions.

There are numerous uncertainties inherent in estimating oil and natural gas reserves and their estimated values, including many factors beyond our control. The reserve data set forth in the reports of our registered independent engineering firms represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geologic interpretation and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development and exploration activities, field tests, data analysis, expectation and assumptions as to availability of financing for development projects, prevailing oil and natural gas prices, operating costs and other factors. The revisions may be material. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based. Estimated quantities of net proved reserves and future net revenues are affected by oil and natural gas prices, which have fluctuated widely in recent years.

Our estimated net proved reserves, included in our SEC filings, have not been filed with or included in reports to any other federal agency.

A decline in estimates of proved reserves may result from lower prices, new information obtained from development drilling and production history, field tests, data analysis, expectation and assumptions as to availability of financing for development projects, mechanical problems on our wells, and catastrophic events such as explosions, hurricanes and floods. Lower prices also may make it uneconomical to drill wells or produce from fields having high operating costs.

Our estimates of proved reserves materially affect depletion expense. If estimated proved reserves decline, then the rate at which we record depletion expense increases, reducing net income. In addition, a decline in estimated proved reserves may affect our assessment of our crude oil and natural gas properties for impairment.

As of June 30, 2011, the Company has no reportable estimated proved undeveloped reserves nor estimated proved developed non-producing reserves. This is a decrease of 27.0 MMBO and 43.3 MMCF (equivalent to approximately 34.2 MMBOE) from the estimated proved undeveloped reserves and a decrease of 1.3 MMBO and 5.7 MMCF (equivalent to approximately 2.3 MMBOE) from estimated proved developed non-producing reserves reported by the Company as of June 20, 2010, when 81% of the Company s estimated proved reserves were classified as proved undeveloped reserves.

These decreases are the result of the application of the requirements of the previously cited Final Rule. Among other things, guidance for the Final Rule for the reporting of estimated proved undeveloped

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reserves requires that a company must have adopted a development plan and have made a final investment decision for their development. The mere intent to develop is not sufficient for reporting estimated proved undeveloped reserves. For all estimated reserves, the Final Rule requires that there must exist, or there must be a reasonable expectation that there will exist, the financing required to implement the development projects. The capital requirement for development of the estimated proved undeveloped and estimated proved developed non-producing reserves previously reported by the Company as of June 30, 2010, was estimated to be approximately $303.5 million and approximately $7.0 million respectively. Due to the Company s current financial constraints, including continued losses, defaults under our loan agreements and our Series D Preferred Stock, no available borrowing capacity, constrained cash flow, negative working capital, and limited to no other capital availability, there is not a reasonable expectation that the Company can obtain the financing required to implement these projects within a reasonable time, even though we believe these projects, in and of themselves, remain technically feasible and economically attractive. Therefore, we have recorded the aforementioned reduction to our estimated reserves.

Our estimated proved reserves are summarized in the table below.

	Crude Oil MBbls	**Natural Gas MMcf (1)**	**Total Reserves MBOE**
Reserves at July 1, 2007	42,330	146,340	66,720
Purchases of minerals in place	1,592	1,680	1,872
Extensions and discoveries	3,894	10,861	5,704
Revisions of prior estimates	(8,403)	(73,097)	(20,586)
Production	(297)	(1,345)	(521)
Reserves at June 30, 2008	39,116	84,439	53,189
Purchases of minerals in place	2,544	472	2,623
Extensions and discoveries	(1,240)	(7,886)	(2,554)
Revisions of prior estimates	(1,338)	(14,191)	(3,703)
Production	(311)	(881)	(458)
Reserves at June 30, 2009	38,771	61,953	49,097
Extensions and discoveries	133	880	279
Sale of minerals in place	(13)	(2,993)	(512)
Revisions of prior estimates	(5,282)	(4,213)	(5,983)
Production	(290)	(671)	(402)
Reserves at June 30, 2010	33,319	54,956	42,479
Extensions and discoveries			
Sale of minerals in place			
Revisions of prior estimates	(29,463)	(50,258)	(37,841)
Production	(264)	(574)	(359)
Reserves at June 30, 2011	3,592	4,124	4,279
Proved developed reserves at June 30, 2008	8,118	29,886	13,099
Proved developed reserves at June 30, 2009	7,027	18,322	10,081
Proved developed reserves at June 30, 2010	6,344	11,705	8,295
Proved developed reserves at June 30, 2011	3,592	4,124	4,279

(1) Separate estimated reserves are not reported for NGLs; instead, estimated natural gas reserves are reported on a wet basis that includes the NGLs subsequently removed from the gas stream.

As described in the Final Rule, proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods, and government regulations. The term reasonable certainty means a high degree of confidence that the quantities of oil and natural gas will be recovered. A high degree of confidence exists if the quantity is much more likely to be achieved than not. Although the

Final Rule permits the optional reporting of estimated probable and possible reserves (both of which are less likely to be recovered than estimated proved reserves), our reserves report, prepared by Haas as of June 30, 2011, has not included probable and

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possible reserves for the Company. The reserves report, as of June 30, 2010, also prepared by Haas, did identify undeveloped probable and possible reserves. In that report, the company s undeveloped probable reserves totaled crude oil and natural gas reserves of 10,442 MBbls and 23,519 MMcf, respectively. The possible reserves in the June 30, 2010, report totaled crude oil and natural gas reserves of 8,563 MBbls and 5,968 MMcf, respectively.

Because of the removal of estimated PUD and PDNP reserves, the reserve estimates for June 30, 2011, are significantly lower than those for prior periods. This has had an impact on depletion and depreciation expense, asset retirement obligation, and impairment of oil and gas properties. In addition, the standardized measure of discounted future net cash flows was approximately $190 million lower as compared that for June 30, 2010.

For the 2011 Fiscal Year, the prices used to compute the estimated crude oil and natural gas proved reserves represent the unweighted average first-day-of-the-month NYMEX crude oil and natural prices for each month in the period. These were $90.09 per barrel and $4.21 per MMBTU, respectively. For the 2010 Fiscal Year, the prices used to compute the crude oil and natural gas proved reserves represent the unweighted average first-day-of-the-month NYMEX crude oil and natural prices for each month in the period. These were $75.76 per barrel and $4.10 per MMBTU, respectively. For the 2009 Fiscal Year, the base prices used to compute crude oil and natural gas reserves represent the NYMEX oil and natural gas prices at June 30, 2009. These were $69.89 per barrel and $3.71 per MMBTU, respectively.

Change in Reserves at June 30, 2011

Proved Developed Producing Reserves

The following table summarizes the changes in our estimated proved developed producing reserves from June 30, 2010, to June 30, 2011. Only estimated Proved Developed Producing (PDP) reserves are represented in the summary of changes below, since estimated non-PDP reserves have been excluded in this filing.

Summary of Changes in Estimated Proved Developed Producing Reserves	**MBOE**
Estimated Reserves at June 30, 2010	6,041
Reserves Revisions	(1,403)
Production for the year ended June 30, 2011	(359)
Estimated Reserves at June 30, 2011	**4,279**

Most of the revisions to our estimated proved developed producing reserves are a result of disruptions in production due to events outside the control of the company. The October 2010 fire in the Cato Field was caused by lightning, and this event not only caused an immediate impact on production, but it has also resulted in a prolonged reduction in production. The Cato waterflood was suspended for 30 days and field production declined as a result. Once injection was returned to previous levels, production has not returned to pre-fire levels. To compound the problem, a variety of mechanical and electrical issues have hampered the company s ability to improve production. Due to the production decline, Haas reduced the estimated PDP reserves projection by placing it immediately on decline. Previously, based on Cano s analytical waterflood models, the production had been held flat for several years, and then placed on decline. Haas reduced the estimated PDP reserves of the Cato properties by 431 MBOE.

During the first quarter of the 2011 Fiscal Year, we reduced the rate of water injection at the Cockrell Ranch and Harvey Ranch units to gain improved operational efficiencies and because of capital constraints. Consequently, the production for these Panhandle properties declined at a quicker pace than previously estimated. Due to the decline in production, Haas reduced our estimated PDP reserves of the Panhandle properties by 718 MBOE.

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Desdemona reserves revisions are relatively insignificant for the company as a whole. However, operating costs increased and gas production fell below the estimates used to prepare our 2010 reserves report. Haas reduced the estimated PDP reserves of the Desdemona properties by 167 MBOE.

Haas made no significant changes to the estimated reserves for the Davenport and Nowata properties.

Capital constraints during this reporting period have inhibited the Company s ability to enhance and fully maintain production.

Our operational and development activities are more fully described below under *Development Capital Expenditures and Operating Activities Update.*

Proved Undeveloped Reserves and Proved Developed Non-Producing Reserves

As of June 30, 2011, the Company has no reportable estimated proved undeveloped reserves or estimated proved developed non-producing reserves. This is a decrease of 27.0 MMBO and 43.3 MMCF (equivalent to approximately 34.2 MMBOE) from the estimated proved undeveloped reserves and a decrease of 1.3 MMBO and 5.7 MMCF (equivalent to approximately 2.3 MMBOE) from the estimated proved developed non-producing reserves reported by the Company as of June 20, 2010.

These decreases are the result of the application of the requirements of the previously cited Final Rule. Among other things, guidance for the Final Rule for the reporting of estimated proved undeveloped reserves requires that a company must have adopted a development plan and have made a final investment decision for their development. The mere intent to develop is not sufficient for reporting estimated proved undeveloped reserves. For all estimated reserves, the Final Rule requires that there must exist, or there must be a reasonable expectation that there will exist, the financing required to implement the development projects. The capital requirement for development of the estimated proved undeveloped and estimated proved developed non-producing reserves previously reported by the Company as of June 30, 2010, was estimated to be approximately $303.5 million and approximately $7.0 million respectively. Due to the Company s current financial constraints, including continued losses, defaults under our loan agreements and our Series D Preferred Stock, no available borrowing capacity, constrained cash flow, negative working capital, and limited to no other capital availability, there is not a reasonable expectation that the Company can obtain the financing required to implement these projects within a reasonable time, even though we believe these projects, in and of themselves, remain technically feasible and economically attractive. Therefore, we have recorded the aforementioned reduction to our estimated reserves.

Change in Reserves at June 30, 2010

Extensions and discoveries totaling 0.3 MMBOE resulted primarily from newly identified behind-pipe opportunities at our Cato and Panhandle Properties.

Sales of minerals in place resulted from the sale of certain wells in the Panhandle Properties as discussed in Note 7.

Revisions in previous quantity estimates resulted primarily from reduced PUD reserves at the Panhandle Properties of 4.4 MMBOE and reduced PDP reserves at the Cato Properties of 0.9 MMBOE.

Haas utilized the East Schafer Ranch waterflood as the analogy for assessing the estimated PUD reserves for each lease of the Panhandle Properties. The East Shafer Ranch waterflood experienced a secondary recovery of 11% of the original oil in place, or OOIP, which equated to a secondary to primary ratio of 0.35. Haas, based solely on its professional experience and engineering judgment, determined that for the purpose of reporting the Panhandle Properties   estimated proved reserves, they would limit each of the Panhandle Properties   waterflood recovery factors to a 0.35 secondary to primary ratio as a maximum, and not use a percentage of OOIP to determine estimated proved reserves. In some cases, adjustments were made since the lease by lease production history appeared to have allocation issues. Haas   decision to limit

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proved reserves recovery based upon a 0.35 secondary to primary ratio resulted in a proved reserves decrease of 3.1 MMBOE. Further, Haas looked at the delayed responses Cano has experienced at its Cockrell Ranch unit, along with reservoir conformance and permeability trends analyzed from core data, and decided to limit estimated proved reserves to a 0.175 secondary to primary ratio for the Cockrell Ranch and the adjacent Pond Lease, resulting in a proved reserves decrease of 1.3 MMBOE. Haas determined that the reductions to the combined company s estimated proved reserves would be validly reclassified as probable reserves as estimated proved reserves indicate a 90% likelihood that production will meet or exceed the booked value while estimated probable reserves require a 50% confidence level to be so classified.

The reduction of estimated PDP reserves at Cato Properties is a result of lower field production rates associated with lower water injection rates at the waterflood.

Change in Reserves at June 30, 2009

• The extensions and discoveries pertain to our drilling and completing wells, and results of the waterflood project in the San Andres formation at our Cato Properties.

• The sales of minerals in place pertain to our divestitures of oil and natural gas properties located in Texas as discussed in Note 7.

• The reduction for revisions of prior estimates pertain to the impairments of our Barnett Shale Properties (Note 12) of 2.3 MMBOE and other revisions of 1.4 MMBOE driven primarily by the decline in commodity prices and estimate changes which reduced the economic life of our assets, as compared to estimated proved reserves as of June 30, 2008. The specific field changes are as follows:

• At the Desdemona Properties - Barnett Shale, production performance due to price accounted for 0.4 MMBOE of negative revisions in PDP, partially offset by a positive 0.1 MMBOE at the Desdemona Properties - Duke Sands projects due to improved recoveries.

• At the Davenport Properties, commodity price-related effects reduced estimated PDP reserves by 0.2 MMBOE.

• At the Nowata Properties, improved recoveries increased estimated PDP reserves by 0.1 MMBOE.

• At the Panhandle Properties, estimated PDP reserves decreased 1.3 MMBOE largely as a result of transferring 0.7 MMBOE to PUD reserves, commodity price-related effects and production, which was partially offset by increased estimated PUD reserves of 0.3 MMBOE a net reduction of 1.0 MMBOE.

Standardized Measure

The standardized measure of discounted future net cash flows (standardized measure) and changes in such cash flows are prepared using assumptions including the use of year-end prices for oil and natural gas and year-end costs for estimated future development and production expenditures to produce year-end estimated proved reserves. Discounted future net cash flows are calculated using a 10% annual discount rate.

Estimated well abandonment costs, net of salvage, are deducted from the standardized measure using year-end costs. Such abandonment costs are recorded as a liability on the consolidated balance sheets, using estimated values of the projected abandonment date and discounted using a risk-adjusted rate at the time the well is drilled or acquired.

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The standardized measure does not represent management s estimate of our future cash flows or the value of proved oil and natural gas reserves. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. Furthermore, year-end prices used to determine the standardized measure of discounted cash flows, are influenced by seasonal demand and other factors and may not be the most representative in estimating future revenues or reserve data.

Price and cost revisions are primarily the net result of changes in year-end prices, based on beginning of year reserve estimates. Quantity estimate revisions are primarily the result of the extended economic life of proved reserves, proved undeveloped reserve additions attributable to increased development activity, reduced reserves due to lower performance from the existing wells, reduced reserves to comply with current industry practice that limited the number of PUD locations that could be booked against existing wells and lower reserves if a company is unable to commit to developing PUD reserves within five years.

Standardized Measure of Discounted Future Cash Flows

The standardized measure of discounted estimated future net cash flows related to proved crude oil and natural gas reserves for the years ended June 30, 2011, 2010, and 2009 is as follows:

In Thousands	**2011**	**2010**	**2009**
Future cash inflows	$ 352,951	$ 2,760,812	$ 2,751,854
Future production costs	(203,370)	(807,541)	(767,743)
Future development costs		(310,469)	(332,677)
Future income taxes		(530,300)	(535,300)
Future net cash flows	149,581	1,112,502	1,116,134
10% annual discount	(82,232)	(855,098)	(834,122)
Standardized measure of discounted future net cash flows	$ 67,349	$ 257,404	$ 282,012

Changes in Standardized Measure of Discounted Future Cash Flows

The primary changes in the standardized measure of discounted estimated future net cash flows for the years ended June 30, 2011, 2010, and 2009 are as follows:

In Thousands	**2011**	**2010**	**2009**
Balance at beginning of year	$ 257,404	$ 282,012	$ 1,412,543
Net changes in prices and production costs	25,908	61,926	(1,598,659)
Net changes in future development costs	210,198	2,557	(36,746)
Sales of oil and gas produced, net	(10,793)	(5,282)	(6,552)
Purchases of reserves			
Sales of reserves		(5,926)	(94,357)
Extensions and discoveries		1,536	38,256
Revisions of previous quantity estimates	(580,295)	(111,904)	(54,017)
Previously estimated development costs incurred		12,056	47,590

Net change in income taxes	156,303	1,271	349,339
Accretion of discount	6,123	47,128	224,235
Other	2,501	(27,970)	380
Balance at end of year	$ 67,349	$ 257,404	$ 282,012