CONTANGO OIL & GAS CO
Form 10-K
August 29, 2012
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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, 2012

[ ] 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 001-16317

CONTANGO OIL & GAS COMPANY
(Exact name of registrant as specified in its charter)

Delaware	95-4079863
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

3700 Buffalo Speedway, Suite 960
Houston, Texas 77098
(Address of principal executive offices)
(713) 960-1901
(Registrant's telephone number, including area code)

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

Common Stock, Par Value $0.04 per share	NYSE MKT

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [ ] 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 [ ] 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 [ ]

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 [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. [X]

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

Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]
(Do not check if smaller reporting company)

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

At December 31, 2011, the aggregate market value of the registrant's common stock held by non-affiliates (based upon the closing sale price of shares of such common stock as reported on the NYSE MKT was $745,499,902. As of August 24, 2012, there were 15,292,448 shares of the registrant's common stock outstanding.

Documents Incorporated by Reference

Items 10, 11, 12, 13 and 14 of Part III have been omitted from this report since registrant will file with the Securities and Exchange Commission, not later than 120 days after the close of its fiscal year, a definitive proxy statement, pursuant to Regulation 14A. The information required by Items 10, 11, 12, 13 and 14 of this report, which will appear in the definitive proxy statement, is incorporated by reference into this Form 10-K.

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
ANNUAL REPORT ON FORM 10-K FOR THE FISCAL YEAR ENDED JUNE 30, 2012
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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Some of the statements made in this report may contain “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, and Section 21E of the Securities Exchange Act of 1934, as amended. The words and phrases “should be”, “will be”, “believe”, “expect”, “anticipate”, “estimate”, “forecast”, “goal” and similar expressi identify forward-looking statements and express our expectations about future events. These include such matters as:

- Our financial position
- Business strategy, including outsourcing
- Meeting our forecasts and budgets
- Anticipated capital expenditures
- Drilling of wells
- Natural gas and oil production and reserves
- Timing and amount of future discoveries (if any) and production of natural gas and oil
- Operating costs and other expenses
- Cash flow and anticipated liquidity
- Prospect development
- Property acquisitions and sales
- New governmental laws and regulations
- Expectations regarding oil and gas markets in the United States

Although we believe the expectations reflected in such forward-looking statements are reasonable, such expectations may not occur. These forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from actual future results expressed or implied by the forward-looking statements. These factors include among others:

- Low and/or declining prices for natural gas and oil
- Natural gas and oil price volatility
- Operational constraints, start-up delays and production shut-ins at both operated and non-operated production platforms, pipelines and gas processing facilities
- The risks associated with acting as the operator in drilling deep high pressure and temperature wells in the Gulf of Mexico, including well blowouts and explosions
- The risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry holes, especially in prospects in which the Company has made a large capital commitment relative to the size of the Company’s capitalization structure
- The timing and successful drilling and completion of natural gas and oil wells
- Availability of capital and the ability to repay indebtedness when due
- Availability of rigs and other operating equipment
- Ability to receive Bureau of Safety and Environmental Enforcement permits on a time schedule that permits the Company to operate efficiently
- Ability to raise capital to fund capital expenditures
- Timely and full receipt of sale proceeds from the sale of our production
- The ability to find, acquire, market, develop and produce new natural gas and oil properties
- Interest rate volatility
- Zero or near-zero interest rates
- Uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures
- Operating hazards attendant to the natural gas and oil business
- Downhole drilling and completion risks that are generally not recoverable from third parties or insurance

- Potential mechanical failure or under-performance of significant wells, production facilities, processing plants or pipeline mishaps
- Weather
- Availability and cost of material and equipment
- Delays in anticipated start-up dates
- Actions or inactions of third-party operators of our properties
- Actions or inactions of third-party operators of pipelines or processing facilities
- The ability to find and retain skilled personnel
- Strength and financial resources of competitors
- Federal and state regulatory developments and approvals
- Environmental risks
- Worldwide economic conditions
- The ability to construct and operate offshore infrastructure, including pipeline and production facilities
- The continued compliance by the Company with various pipeline and gas processing plant specifications for the gas and condensate produced by the Company
- Drilling and operating costs, production rates and ultimate reserve recoveries in our Eugene Island 10 (“Dutch”) and state of Louisiana (“Mary Rose”) acreage
- Restrictions on permitting activities
- Expanded rigorous monitoring and testing requirements
- Legislation that may regulate drilling activities and increase or remove liability caps for claims of damages from oil spills
- Ability to obtain insurance coverage on commercially reasonable terms
- Accidental spills, blowouts and pipeline ruptures
- Impact of new and potential legislative and regulatory changes on Gulf of Mexico operating and safety standards

You should not unduly rely on these forward-looking statements in this report, as they speak only as of the date of this report. Except as required by law, we undertake no obligation to publicly release any revisions to these forward-looking statements to reflect events or circumstances occurring after the date of this report or to reflect the occurrence of unanticipated events. See the information under the heading “Risk Factors” referred to on page 13 of this report for some of the important factors that could affect our financial performance or could cause actual results to differ materially from estimates contained in forward-looking statements.

All references in this Form 10-K to the “Company”, “Contango”, “we”, “us” or “our” are to Contango Oil & Gas Company and wholly-owned Subsidiaries. Unless otherwise noted, all information in this Form 10-K relating to natural gas and oil reserves and the estimated future net cash flows attributable to those reserves are based on estimates prepared by independent engineers and are net to our interest.

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PART I
Item 1. Business
Overview
Contango is a Houston-based, independent natural gas and oil company. The Company's core business is to explore, develop, produce and acquire natural gas and oil properties onshore and offshore in the Gulf of Mexico in water-depths of less than 300 feet. Contango Operators, Inc. ("COI"), our wholly-owned subsidiary, acts as operator on our properties.
Our Strategy
Our exploration strategy is predicated upon two core beliefs: (1) that the only competitive advantage in the commodity-based natural gas and oil business is to be among the lowest cost producers and (2) that virtually all the exploration and production industry's value creation occurs through the drilling of successful exploratory wells. As a result, our business strategy includes the following elements:
Funding exploration prospects generated by Juneau Exploration, L.P., our alliance partner. We depend primarily upon our alliance partner, Juneau Exploration, L.P. ("JEX"), for prospect generation expertise. JEX is experienced and has a successful track record in exploration.
Using our limited capital availability to increase our reward/risk potential on selective prospects. We have concentrated our risk investment capital in the exploration of i) offshore Gulf of Mexico prospects and ii) conventional and unconventional onshore plays. Exploration prospects are inherently risky as they require large amounts of capital with no guarantee of success. COI drills and operates our prospects. Should we be successful in any of our offshore prospects, we will have the opportunity to spend significantly more capital to complete development and bring the discovery to producing status.
Sale of proved properties. From time-to-time as part of our business strategy, we have sold and in the future expect to continue to sell some or a substantial portion of our proved reserves and assets to capture current value, using the sales proceeds to further our offshore exploration activities. Since its inception, the Company has sold approximately $524 million worth of natural gas and oil properties, and views periodic reserve sales as an opportunity to capture value, reduce reserve and price risk, and as a source of funds for potentially higher rate of return natural gas and oil exploration opportunities.
Controlling general and administrative and geological and geophysical costs. Our goal is to be among the most efficient in the industry in revenue and profit per employee and among the lowest in general and administrative costs. We have ten employees. We plan to continue outsourcing our geological, geophysical, and reservoir engineering and land functions, and partnering with cost efficient operators.
Structuring incentives to drive behavior. We believe that equity ownership aligns the interests of our employees and stockholders. Our directors and executive officers beneficially own or have voting control over approximately 17% of our common stock.

Exploration Alliance with JEX
JEX is a private company formed for the purpose of generating offshore and onshore domestic natural gas and oil prospects. Additionally, JEX can generate offshore prospects through our 32.3% owned affiliated company, Republic Exploration LLC ("REX"). In addition to generating new prospects, JEX occasionally evaluates offshore and onshore exploration prospects generated by third-party independent companies for us to purchase. Once we have purchased a prospect from JEX, REX or a third-party, we have historically entered into participation agreements and joint operating agreements, which specify each participant's working interest, net revenue interest, and describe when such interests are earned, as well as allocate an overriding royalty interest of up to 3.33% to benefit employees of JEX. See Note 13 - Related Party Transactions for a detailed description of our transactions with JEX and REX.
On April 10, 2012, the Company announced that Mr. Brad Juneau, the sole manager of the general partner of JEX, had joined the Company's board of directors and that the Company had entered into an advisory agreement with JEX (the "Advisory Agreement"), whereby in addition to generating and evaluating offshore and onshore exploration prospects for the Company, JEX will direct Contango's staff on operational matters including drilling, completions and

production. Pursuant to the Advisory Agreement, JEX will be paid an annual fee of $2 million and JEX, or employees of JEX, will continue to be eligible to receive overriding royalty interests, carried interests and certain back-in rights.

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Offshore Gulf of Mexico Activities

Contango, through its wholly-owned subsidiary, COI and its partially-owned affiliate, REX, conducts exploration activities in the Gulf of Mexico. COI drills, and operates our wells in the Gulf of Mexico, as well as attends lease sales and acquires leasehold acreage. Additionally, COI may acquire significant working interests in offshore exploration and development opportunities in the Gulf of Mexico, under farm-out agreements, or similar agreements, with REX, JEX and/or other third parties.

As of August 24, 2012, the Company's offshore production was approximately 83.5 million cubic feet equivalent per day ("Mmcfed"), net to Contango, which consists mainly of seven federal and five state of Louisiana wells in the shallow waters of the Gulf of Mexico. These 12 operated wells produce via the following four platforms:

Eugene Island 24 Platform

This third-party owned and operated production platform at Eugene Island 24 was designed with a capacity of 100 million cubic feet per day ("Mmcfd") and 3,000 barrels of oil per day ("bopd"). This platform services production from the Company’s Dutch #1, #2 and #3 federal wells. From this platform, the gas flows through an American Midstream pipeline into a third-party owned and operated on-shore processing facility at Burns Point, Louisiana, and the condensate flows via an ExxonMobil pipeline to on-shore markets and multiple refineries. As of August 24, 2012, we were producing approximately 22.5 Mmcfed, net to Contango, from this platform.

The Company recently finished laying 6" auxiliary flowlines from the Dutch #1, #2, and #3 wells to our Eugene Island 11 Platform (see below) and is in the process of redirecting production from the Eugene Island 24 Platform to the Eugene Island 11 Platform. Our cost estimate for the installation of these three flowlines is $2.5 million, net to Contango. As of June 30, 2012, the Company had incurred approximately $0.8 million to install these flowlines.

Eugene Island 11 Platform

Our Company-owned and operated platform at Eugene Island 11 was designed with a capacity of 500 Mmcfd and 6,000 bopd. In September 2010 the Company installed a companion platform and two pipelines adjacent to the Eugene Island 11 platform to be able to access alternate markets. These platforms service production from the Company’s five Mary Rose wells which are all located in state of Louisiana waters, as well as our Dutch #4 and Dutch #5 wells which are both located in federal waters. From these platforms, we can flow our gas to an American Midstream pipeline via our 8” pipeline and from there to a third-party owned and operated on-shore processing facility at Burns Point, Louisiana. We can flow our condensate via an ExxonMobil pipeline to on-shore markets and multiple refineries.

Alternatively, our gas and condensate can flow to our Eugene Island 63 auxiliary platform via our 20” pipeline, which has been designed with a capacity of 330 Mmcfd and 6,000 bopd, and from there to third-party owned and operated on-shore processing facilities near Patterson, Louisiana, via an ANR pipeline. As of August 24, 2012, we were producing approximately 44.6 Mmcfed, net to Contango, from this platform.

Based on production and decline rates, the Company has recently determined the need to place its Dutch and Mary Rose wells on compression in 2013. The Company is in the process of designing and building a large turbine type compressor for the platform at an estimated cost of $6.8 million, net to Contango. This compressor will be of sufficient capacity to service all ten of the Company's Dutch and Mary Rose wells. As of June 30, 2012, the Company had incurred approximately $2.3 million to design and build the compressor, which is expected to be installed in June 2013.

Ship Shoal 263 Platform

Our Company-owned and operated platform at Ship Shoal 263 was designed with a capacity of 40 Mmcfd and 5,000 bopd. This platform services natural gas and condensate production from our Nautilus well, which flows via the Transcontinental Gas Pipeline to onshore processing plants. As of August 24, 2012, we were producing approximately 3.0 Mmcfed, net to Contango, from this platform.

Effective October 1, 2010, the Company purchased an additional 7.5% working interest and 6.0% net revenue interest in Ship Shoal 263 for approximately $7.5 million from JEX. The Company now owns a 100% working interest and

80% net revenue interest in this well and platform.

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Vermilion 170 Platform

Our Company-owned and operated platform at Vermilion 170 was designed with a capacity of 60 Mmcfd and 2,000 bopd. This platform services natural gas and condensate production from our Swimmy well, which flows via the Sea Robin Pipeline to onshore processing plants. As of August 24, 2012, we were producing approximately 13.4 Mmcfed, net to Contango, from this platform.

Based on current production and decline rates, the Company has determined the need to place its Vermilion 170 well on compression in 2013, at a cost of $1.4 million, net to Contango. As of June 30, 2012, the Company had incurred approximately $0.4 million to design and build a compressor to service its Swimmy well, which is expected to be completed in late 2012.

Other Activities

On July 10, 2012 we spud our South Timbalier 75 prospect ("Fang") with the Spartan 303 rig. The Company farmed-in this prospect in August 2011 from an independent third party. We have a 100% working interest in this wildcat exploration prospect, subject to back-ins if successful, and have budgeted to invest approximately $28.0 million to drill this well. As of June 30, 2012, the Company had invested approximately $0.4 million in Fang, which includes leasehold costs.

On July 3, 2012, we spud our Ship Shoal 134 prospect ("Eagle") with the Hercules 205 rig. The Company purchased the deep mineral rights on Ship Shoal 134 from an independent third-party effective February 24, 2011. We have a 100% working interest in this wildcat exploration prospect, subject to back-ins if successful, and have budgeted approximately $25.0 million to drill this well. As of June 30, 2012, the Company had invested approximately $6.5 million in Eagle, which includes leasehold costs. We expect to know the drilling results of both the Eagle and Fang wells by November 2012.

On June 20, 2012, the Company was the apparent high bidder on six lease blocks at the Central Gulf of Mexico Lease Sale 216/222. The Company bid an aggregate amount of approximately $11 million on the following six blocks:

- East Cameron 124
- Eugene Island 31
- Eugene Island 260
- Ship Shoal 83
- Ship Shoal 255
- South Timbalier 110

An apparent high bid (“AHB”) is subject to Outer Continental Shelf (“OCS”) Bid Adequacy Review. The Bureau of Ocean Energy Management (“BOEM”) (formerly the Minerals Management Service) may reject all bids for a given tract. The BOEM review process can take up to 90 days. Upon approval from the BOEM, our plan is to promptly obtain permits to drill these prospects and to drill them in 2013 and 2014. The Company will have a 100% working interest in these prospects, subject to back-ins if successful. In August 2012, the Company was notified that it had been awarded East Cameron 124, Eugene Island 31, Ship Shoal 83 and South Timbalier 110 effective September 1, 2012.

On March 1, 2012, the Company was awarded Brazos Area 543 by the BOEM, which was bid on at the Western Gulf of Mexico Lease Sale No. 218 held on December 14, 2011. As of June 30, 2012, the Company had invested approximately $0.4 million in Brazos Area 543, which includes leasehold costs.

In June 2011, we completed a workover of our Eloise North well at a cost of approximately $1.8 million, net to Contango, which enabled us to continue producing from the lower Rob-L sands. In October 2011, we commenced a workover of our Eloise North well to recomplete the well in the upper Rob-L sands. During the workover, the Company experienced difficulties and unexpected delays due to malfunctioning production tree valves, coiled tubing equipment failures, weather delays, and stuck equipment in the tubing. As a result, the Company plugged the Rob-L sands in January 2012 and recompleted uphole in the Cib-Op sands as our Mary Rose #5 well, at a cost of approximately $0.5 million, net to Contango, based on the new higher ownership percentage and inclusive of a required well cost adjustment. The Mary Rose #5 well began producing on January 26, 2012 and by mid-March 2012 had stopped again. We are currently flowing the well intermittently until we can install compression in 2013.

On December 21, 2011, the Company purchased an additional 3.66% working interest (2.67% net revenue interest) in Mary Rose #5 (previously Eloise North) for approximately $0.2 million from an existing partner. This purchase brings the Company’s working interest and net revenue interest in Mary Rose #5 to 37.80% and 27.59%, respectively.

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In July 2011, we recompleted our Eloise South well uphole in the Cib-Op sands as our Dutch #5 well, at a cost of approximately $5.7 million, net to Contango. The Company has a 47.05% working interest (38.1% net revenue interest) in Dutch #5. In addition to this $5.7 million, the Dutch #5 well owners purchased the Eloise South well bore from the Eloise South well owners (the “Well Cost Adjustment”). The Company invested a net of approximately $2.3 million related to this Well Cost Adjustment.

In September 2010, we drilled our Galveston Area 277L prospect (“His Dudeness”), a wildcat exploration well in the Gulf of Mexico, and determined it was a dry hole. The Company invested approximately $9.5 million, including leasehold costs, to drill, plug and abandon this well.

During the fiscal year ended June 30, 2010, we drilled two dry holes in the Gulf of Mexico. The first was on a farm-in we obtained on block Vermillion 155 (“Paisano”). This well had a dry hole cost of approximately $5.3 million. The second was our Matagorda Island 617 well (“Dude”), with a dry hole cost of approximately $14.9 million. The Company had a 100% working interest in both of these wells.

Republic Exploration LLC

In his capacity as sole manager of the general partner of JEX, Mr. Juneau also controls the activities of REX, an entity owned 34.4% by JEX, 32.3% by Contango, and 33.3% by a third party which contributed other assets to REX. REX generates and evaluates offshore exploration prospects and has historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specify each participant’s working interest, net revenue interest, and describe when such interests are earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX. The Company proportionately consolidates the results of REX in its consolidated financial statements.

West Delta 36, a REX prospect, is operated by a third party. The Company depends on a third-party operator for the operation and maintenance of this production platform. As of August 24, 2012, the well was in the process of being recompleted uphole, at a cost of approximately $0.1 million, net to Contango. REX has a 25.0% working interest (“WI”), and a 20.0% net revenue interest (“NRI”), in this well.

Contango Offshore Exploration LLC

Prior to its dissolution on June 1, 2010, in his capacity as sole manager of the general partner of JEX, Mr. Juneau controlled the activities of Contango Offshore Exploration LLC ("COE"), an entity then owned 65.63% by Contango and 34.37% by JEX. COE generated and evaluated offshore exploration prospects and had historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specified each participant’s working interest, net revenue interest, and described when such interests were earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX. The Company proportionately consolidated the results of COE in its consolidated financial statements.

Immediately prior to its dissolution, COE owed the Company $5.9 million in principal and interest under a promissory note (the “COE Note”) payable on demand. In connection with the dissolution, the Company assumed its 65.6% share of the obligation under the COE Note, while JEX assumed the remaining 34.4%, or approximately $2 million. This $2 million was paid back to the Company during the fiscal year ended June 30, 2011.

Offshore Properties

During the fiscal year ended June 30, 2012, State Lease 19396 expired and was returned to the state of Louisiana. During the fiscal year ended June 30, 2011, the Company relinquished 12 lease blocks to the BOEM, and allowed two additional lease blocks to expire in accordance with their terms.

Producing Properties. The following table sets forth the interests owned by Contango through its affiliated entities in the Gulf of Mexico which were capable of producing natural gas or oil as of August 24, 2012:

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Area/Block	WI	NRI	Status
Eugene Island 10 #D-1 (Dutch #1)	47.05%	38.1%	Producing
Eugene Island 10 #E-1 (Dutch #2)	47.05%	38.1%	Producing
Eugene Island 10 #F-1 (Dutch #3)	47.05%	38.1%	Producing
Eugene Island 10 #G-1 (Dutch #4)	47.05%	38.1%	Producing
Eugene Island 10 #I-1 (Dutch #5)	47.05%	38.1%	Producing
S-L 18640 #1 (Mary Rose #1)	53.21%	40.5%	Producing
S-L 19266 #1 (Mary Rose #2)	53.21%	38.7%	Producing
S-L 19266 #2 (Mary Rose #3)	53.21%	38.7%	Producing
S-L 18860 #1 (Mary Rose #4)	34.58%	25.5%	Producing
S-L 19266 #3 and S-L 19261 (Mary Rose #5)	37.80%	27.6%	Intermittent
Ship Shoal 263 (Nautilus)	100.00%	80.0%	Producing
Vermilion 170 (Swimmy)	87.24%	68.0%	Producing
West Delta 36 (via REX)	8.1%	6.5%	Producing

Leases. The following table sets forth the interests owned by Contango through its related entities in leases in the Gulf of Mexico as of August 24, 2012:

Area/Block	WI	Lease Date	Expiration Date
Eugene Island 11	53.21%	Dec 07	Dec-12
East Breaks 369 (1)	(2)	Dec-03	Dec-13
South Timbalier 97 (via REX)	32.30%	Jun-09	Jun-14
Ship Shoal 121	100.00%	Jul-10	Jul-15
Ship Shoal 122	100.00%	Jul-10	Jul-15
Brazos Area 543	100.00%	Mar-12	Mar-17
Ship Shoal 134	100.00%	(3)	(3)
South Timbalier 75	100.00%	(4)	(4)

(1) Dry Hole
(2) Farm-out. COI retains a 2.41% ORRI
(3) Purchased deep rights. Currently drilling
(4) Farm-in. Currently drilling. Will earn lease once production begins (if successful)

Onshore Exploration and Properties

Alta Investments

On April 12, 2011, the Company announced a commitment to invest up to $20 million over two years in Alta Energy Canada Partnership (“Alta Energy”), a venture that will acquire, explore, develop and operate onshore unconventional oil and natural gas shale assets. As of August 24, 2012, we had invested approximately $12.3 million in Alta Energy to purchase over 60,000 acres in the Kaybob Duvernay, a liquids rich shale play in Alberta, Canada. Alta Energy has built one of the largest acreage blocks in the core of the play. Alta Energy drilled and cored its first vertical well in 17 days which is highly competitive with offset operators. Alta Energy has drilled three vertical test wells and has taken whole cores on two of those.

Offsetting activity in the Kaybob Duvernay continues to provide encouraging early results. With four horizontal well results available, initial production began with 508 barrels of oil equivalent per day ("Boed") for the first well and continuously improved to 2,123 Boed for the fourth well which tested 7.7 MMcfd and 839 Bbls per day. Condensate yields continue to rise to close to 100 bbls/MMcf plus encouraging amounts of NGL's. We expect an active summer of offsetting activity with additional information being slowly provided by competitors to the market. Alta Energy began its summer drilling program which included spudding Alta's first horizontal well. Contango has a 2% interest in Alta Energy and a 5% interest in the Kaybob Duvernay project.

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Exaro Energy III LLC

On April 9, 2012, the Company announced that through its wholly-owned subsidiary, Contaro Company, it had entered into a Limited Liability Company Agreement (the “LLC Agreement”) to form Exaro Energy III LLC (“Exaro”). Pursuant to the LLC Agreement, the Company has committed to invest up to $82.5 million in cash in Exaro over the next five years together with other parties for an aggregate commitment of $182.5 million. The Company owns approximately a 45% interest in Exaro, subject to terms allowing another party to acquire up to $15 million of the Company’s commitment, which would decrease the Company’s interest in Exaro to approximately 37%.

As of June 30, 2012, the Company had invested approximately $41.3 million in Exaro. Exaro has entered into an Earning and Development Agreement (the “EDA Agreement”) with Encana Oil & Gas (USA) Inc. (“Encana”) to provide funding of up to $380 million to continue the development drilling program in a defined area of Encana’s Jonah field asset located in Sublette County, Wyoming. This funding will be comprised of the $182.5 million investment detailed above, debt, and cash flow from operations. Encana will continue to be the operator of the field and upon investing the full amount of the $380 million, Exaro will have earned 32.5% of Encana’s working interest in a defined joint venture area that comprises approximately 5,760 gross acres.

The Exaro-Encana venture currently has three rigs drilling, has completed five wells to date and achieved first production during mid-June 2012. The drilling project is progressing on schedule. As of June 30, 2012, there were no material natural gas or oil reserves associated with our investment in Exaro. During the period from inception to June 30, 2012, Exaro incurred a loss of approximately $1.5 million, of which approximately $0.5 million was recognized in the Company's consolidated statement of operations (net of $0.2 million in taxes) for the fiscal year ended June 30, 2012.

Tuscaloosa Marine Shale

As of August 24, 2012, the Company had invested approximately $8.7 million to lease approximately 25,000 acres in the Tuscaloosa Marine Shale ("TMS"), a shale play in central Louisiana and Mississippi. The TMS is an oil focused play and we intend to watch the play develop before we commit to drilling any exploratory wells. We do, however, plan to participate in outside operated wells with a small working interest prior to initiating an operated, high interest drilling program.

Jim Hogg County, Texas

We have entered into a letter agreement with a large south Texas mineral owner outlining the general terms and conditions of an exploration program involving acreage in Jim Hogg County, Texas. As of August 24, 2012, we had paid approximately $1.2 million into this exploration program.

Discontinued Operations

Joint Venture Assets

In October 2009, the Company entered into a joint venture with Patara Oil & Gas LLC ("Patara") to develop proved undeveloped Cotton Valley gas reserves in Panola County, Texas. B.A. Berilgen, a member of the Company’s board of directors, is the Chief Executive Officer of Patara. On May 13, 2011, the Company sold to Patara its 90% interest and 5% overriding royalty interest in the 21 wells drilled under this joint venture for approximately $36.2 million and recognized a pre-tax loss of approximately $0.7 million. These 21 wells had proved reserves of approximately 16.7 Bcfe, net to Contango. The Company accounted for this sale as discontinued operations as of June 30, 2011 and has included the results of the joint venture operations in discontinued operations for all periods presented.

Rexer Assets

On May 13, 2011, the Company sold to Patara 100% of its interest in Rexer #1 and 75% of its interest in Rexer-Tusa #2 for approximately $2.5 million and recognized a pre-tax loss of approximately $0.3 million. Rexer #1 was a wildcat exploration well that was spud in June 2010 and began producing in October 2010. This well had proved

reserves of approximately 0.5 Bcfe, net to Contango.
The remaining 25% working interest in Rexer-Tusa #2 was sold to Patara in October 2011 for $10,000. Rexer-Tusa #2 was a wildcat exploration well that was spud in May 2011. This well had no proved reserves at the time of sale. The Company has accounted for the sale of Rexer #1 and Rexer-Tusa #2 as discontinued operations as of December 31, 2011 and has included the results of these operations in discontinued operations for all periods presented.

Contango Mining Company

Contango Mining Company ("Contango Mining"), a wholly-owned subsidiary of the Company and the predecessor to Contango ORE, Inc. ("CORE"), was initially formed on October 15, 2009 as a Delaware corporation registered to do business

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in Alaska for the purpose of engaging in exploration in the State of Alaska for (i) gold and associated minerals and (ii) rare earth elements. Contango Mining held leasehold interests in approximately 675,000 acres from the Tetlin Village Council, the council formed by the governing body for the Native Village of Tetlin, an Alaska Native Tribe, as well as additional acres in unpatented Federal and State of Alaska mining claims for the exploration of gold deposits and associated minerals and rare earth elements (collectively, the "Properties").

On November 29, 2010, CORE, then another wholly-owned subsidiary of the Company, acquired the assets and assumed the obligations of Contango Mining, including the Properties, in exchange for its common stock which was subsequently distributed to the Company's stockholders of record as of October 15, 2010 on the basis of one share of common stock for each ten shares of the Company's common stock then outstanding. No fractional shares were issued, but a cash payment was made to shareholders with less than ten shares based upon the value established for CORE. The Company also contributed $3.5 million in cash to CORE immediately prior to the distribution. The Company no longer has an ownership in CORE and has included its results of operations and gain on disposition in discontinued operations for all periods presented.

Marketing and Pricing

The Company currently derives its revenue principally from the sale of natural gas and oil. As a result, the Company's revenues are determined, to a large degree, by prevailing natural gas and oil prices. The Company currently sells its natural gas and oil on the open market at prevailing market prices. Major purchasers of our natural gas, oil and natural gas liquids for the fiscal year ended June 30, 2012 were Shell Trading US Company (25%), NJR Energy Services (13%), ConocoPhillips Company (22%), Exxon Mobil Oil Corporation (11%), Enterprise Products Operating LLC (14%), and TransLouisiana Gas Pipeline Inc. (8%). Market prices are dictated by supply and demand, and the Company cannot predict or control the price it receives for its natural gas and oil. The Company has outsourced the marketing of its offshore natural gas and oil production volume to a privately-held third party marketing firm.

Price decreases would adversely affect our revenues, profits and the value of our proved reserves. Historically, the prices received for natural gas and oil have fluctuated widely. Among the factors that can cause these fluctuations are:

- The domestic and foreign supply of natural gas and oil
- Overall economic conditions
- The level of consumer product demand
- Adverse weather conditions and natural disasters
- The price and availability of competitive fuels such as heating oil and coal
- Political conditions in the Middle East and other natural gas and oil producing regions
- The level of LNG imports
- Domestic and foreign governmental regulations
- Special taxes on production
- The loss of tax credits and deductions

Competition

The Company competes with numerous other companies in all facets of its business. Our competitors in the exploration, development, acquisition and production business include major integrated oil and gas companies as well as numerous independents, including many that have significantly greater financial resources and in-house technical expertise.

Governmental Regulations

Federal Income Tax. Federal income tax laws significantly affect the Company's operations. The principal provisions affecting the Company are those that permit the Company, subject to certain limitations, to deduct as incurred, rather than to capitalize and amortize, its domestic "intangible drilling and development costs" and to claim depletion on a portion of its domestic natural gas and oil properties and to claim a manufacturing deduction based on qualified production activities.

Environmental Matters. Domestic natural gas and oil operations are subject to extensive federal regulation and, with respect to federal leases, to interruption or termination by governmental authorities on account of environmental and other considerations such as the Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”) also known as the “Super Fund Law”. The trend towards stricter standards in environmental legislation and regulation could increase costs to the Company and others in the industry. Natural gas and oil lessees are subject to liability for the costs of clean-up of pollution resulting from a lessee’s operations, and may also be subject to liability for pollution damages. The Company maintains insurance against costs of clean-up operations, but is not fully insured against all such risks. A serious incident of pollution may also result in the Department of the Interior requiring lessees under federal leases to suspend or cease operation in the affected area.

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The Oil Pollution Act of 1990 (the "OPA") and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in U.S. waters. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of federal safety, construction or operating regulations. Few defenses exist to the liability imposed by the OPA. In addition, to the extent the Company's offshore lease operations affect state waters, the Company may be subject to additional state and local clean-up requirements or incur liability under state and local laws. The OPA also imposes ongoing requirements on responsible parties, including proof of financial responsibility to cover at least some costs in a potential spill. The Company believes that it currently has established adequate proof of financial responsibility for its offshore facilities. However, the Company cannot predict whether financial responsibility requirements under any OPA amendments will result in the imposition of substantial additional annual costs to the Company in the future or otherwise materially adversely affect the Company. The impact, however, should not be any more adverse to the Company than it will be to other similarly situated or less capitalized owners or operators in the Gulf of Mexico.
The Company's operations are subject to numerous federal, state and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Such laws and regulations, among other things, impose absolute liability on the lessee for the cost of clean-up of pollution resulting from a lessee's operations, subject the lessee to liability for pollution damages, may require suspension or cessation of operations in affected areas, and impose restrictions on the injection of liquids into subsurface aquifers that may contaminate groundwater. Such laws could have a significant impact on the operating costs of the Company, as well as the natural gas and oil industry in general. Federal, state and local initiatives to further regulate the disposal of natural gas and oil wastes are also pending in certain jurisdictions, and these initiatives could have a similar impact on the Company. The Company's operations are also subject to additional federal, state and local laws and regulations relating to protection of human health, natural resources, and the environment pursuant to which the Company may incur compliance costs or other liabilities.
Impact of Deepwater Horizon Incident. In April 2010, the deepwater Gulf of Mexico drilling rig Deepwater Horizon, engaged in drilling operations for another operator, sank after an apparent blowout and fire. The accident resulted in the loss of life and a significant oil spill and highlighted the dangers associated with exploration and production activities.

The legislative and regulatory response to the Deepwater Horizon Incident is ongoing. In 2010, the US Department of the Interior issued new rules designed to improve drilling and workplace safety, and various Congressional committees began pursuing legislation to greater regulate drilling activities and increase liability. In January 2011, the President's National Commission on the Deepwater Horizon Oil Spill and Offshore Drilling released its report, recommending that the federal government require additional regulation and an increase in liability caps.

Additional regulatory review, slower permitting processes and increased oversight have resulted in longer development cycle time for our Gulf of Mexico projects. Cycle time is the length of time it takes for a project to progress from developing a prospect to beginning production, and longer development cycle times could result in lower rates of return on our investments.

Increased regulation impacting our activities in the Gulf of Mexico could result in extensive efforts to ensure compliance and incremental compliance costs. A significant delay or cancellation of our planned Gulf of Mexico exploratory activities will reduce our longer term ability to replace reserves, resulting in a negative impact on production over time. To the extent current exploration activities are significantly delayed, a gap could occur in our long-term production profile with a negative impact on our operating results and cash flows.

Additional legislation or regulation is being discussed which could require each company doing business in the Gulf of Mexico to establish and maintain a higher level of financial responsibility under its Certificate of Financial Responsibility ("COFR"), a certificate required under the Oil Pollution Act of 1990 which evidences a company’s financial ability to pay for cleanup and damages caused by oil spills. There have also been discussions regarding the establishment of a new industry mutual fund in which companies would be required to participate and which would be available to pay for consequential damages arising from an oil spill. These and/or other legislative or regulatory changes could require us to maintain a certain level of financial strength and may reduce our financial flexibility.

Future legislation or regulation is also likely to result in substantial increases in civil or criminal fines or sanctions. Such fines or sanctions could well exceed the actual cost of containment and cleanup associated with a well incident or spill. We are monitoring legislative and regulatory developments; however, the full legislative and regulatory response to the Deepwater Horizon Incident is not yet fully known.

Other Laws and Regulations. Various laws and regulations often require permits for drilling wells and also cover spacing of wells, the prevention of waste of natural gas and oil including maintenance of certain gas/oil ratios, rates of production and other matters. The effect of these laws and regulations, as well as other regulations that could be promulgated by the jurisdictions in which the Company has production, could be to limit the number of wells that could be drilled on the Company's properties and to limit the allowable production from the successful wells completed on the Company's properties, thereby limiting the Company's revenues.

The BOEM administers the natural gas and oil leases held by the Company on federal onshore lands and offshore tracts in the Outer Continental Shelf. The BOEM holds a royalty interest in these federal leases on behalf of the federal government. While the royalty interest percentage is fixed at the time that the lease is entered into, from time to time the BOEM changes or reinterprets the applicable regulations governing its royalty interests, and such action can indirectly affect the actual royalty obligation that the Company is required to pay. However, the Company believes that the regulations generally do not impact the Company to any greater extent than other similarly situated producers. At the end of lease operations, oil and gas lessees must plug and abandon wells, remove platforms and other facilities, and clear the lease site sea floor. The BOEM requires companies operating on the Outer Continental Shelf to obtain surety bonds to ensure performance of these obligations. As an operator, the Company is required to obtain surety bonds of $200,000 per lease for exploration and $500,000 per lease for developmental activities.

The Federal Energy Regulatory Commission (the "FERC") has embarked on wide-ranging regulatory initiatives relating to natural gas transportation rates and services, including the availability of market-based and other alternative rate mechanisms to pipelines for transmission and storage services. In addition, the FERC has announced and implemented a policy allowing pipelines and transportation customers to negotiate rates above the otherwise applicable maximum lawful cost-based rates on the condition that the pipelines alternatively offer so-called recourse rates equal to the maximum lawful cost-based rates. With respect to gathering services, the FERC has issued orders declaring that certain facilities owned by interstate pipelines primarily perform a gathering function, and may be transferred to affiliated and non-affiliated entities that are not subject to the FERC's rate jurisdiction. The Company cannot predict the ultimate outcome of these developments, or the effect of these developments on transportation rates. Inasmuch as the rates for these pipeline services can affect the natural gas prices received by the Company for the sale of its production, the FERC's actions may have an impact on the Company. However, the impact should not be substantially different for the Company than it would be for other similarly situated natural gas producers and sellers.

Risk and Insurance Program

In accordance with industry practice, we maintain insurance against many, but not all, potential perils confronting our operations and in coverage amounts and deductible levels that we believe to be economic. Consistent with that profile, our insurance program is structured to provide us financial protection from significant losses resulting from damages to, or the loss of, physical assets or loss of human life, and liability claims of third parties, including such occurrences as well blowouts and weather events that result in oil spills and damage to our wells and/or platforms. Our goal is to balance the cost of insurance with our assessment of the potential risk of an adverse event. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and we regularly review our risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

We expect the future availability and cost of insurance to be impacted by the Deepwater Horizon Incident. Impacts could include: tighter underwriting standards, limitations on scope and amount of coverage, and higher premiums, and will depend, in part, on future changes in laws and regulations regarding exploration and production activities in the Gulf of Mexico, including possible increases in liability caps for claims of damages from oil spills. We will continue to monitor the expected regulatory and legislative response and its impact on the insurance market and our overall risk profile, and adjust our risk and insurance program to provide protection at a level that we can afford considering the cost of insurance, against the potential and magnitude of disruption to our operations and cash flows.

We carry insurance protection for our net share of any potential financial losses occurring as a result of events such as the Deepwater Horizon Incident. As a result of the incident, we have increased our well control coverage from $75 million to $100 million on certain wells, which covers control of well, pollution cleanup and consequential damages. We have increased our general liability coverage from $100 million to $150 million, which covers pollution cleanup, consequential damages coverage, and third party personal injury and death. And we have increased our Oil Spill Financial Responsibility coverage from $35 million to $150 million, which covers additional pollution cleanup and third party claims coverage.

Health, Safety and Environmental Program. The Company’s Health, Safety and Environmental (“HS&E”) Program is supervised by an operating committee of senior management to insure compliance with all state and federal regulations. In addition, to support the operating committee, we have contracted with J. Connors Consulting (“JCC”) to manage our regulatory

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process. JCC is a regulatory consulting firm specializing in the offshore Gulf of Mexico regulatory process, preparation of incident response plans, safety and environmental services and facilitation of comprehensive oil spill response training and drills to oil and gas companies and pipeline operators.

For our Gulf of Mexico operations, we have a Regional Oil Spill Plan in place with the BOEM. Our response team is trained annually and is tested through annual spill drills given by the BOEM. In addition, we have in place a contract with O'Brien's Response Management ("O'Brien's"). O'Brien's maintains a 24/7 manned incident command center located in Slidell, LA. Upon the occurrence of an oil spill, the Company's spill program is initiated by notifying O'Brien's that we have an emergency. While the Company would focus on source control of the spill, O'Brien's would handle all communication with state and federal agencies as well as U.S. Coast Guard notifications.

If a spill were to occur, we have contracted with Clean Gulf Associates ("CGA") to assist with equipment and personnel needs. CGA specializes in onsite control and cleanup and is on 24 hour alert with equipment currently stored at six bases (Ingleside and Galveston, TX and Lake Charles, Houma, Venice and Pascagoula, LA), and is opening new sites in Leeville, Morgan City and Harvey, LA. The CGA equipment stockpile is available to serve member oil spill response needs including blowouts; open seas, near shore and shallow water skimming; open seas and shoreline booming; communications; dispersants; boat spray systems to apply dispersants; wildlife rehabilitation; and a forward command center. CGA has retainers with an aerial dispersant company and a company that provides mechanical recovery equipment for spill responses. CGA equipment includes:

- HOSS Barge: the largest purpose-built skimming barge in the United States with 4,000 barrels of storage capacity.
- Fast Response System (FRU): a self-contained skimming system for use on vessels of opportunity. CGA has nine of these units.
- Fast Response Vessels (FRV): four 46 foot FRVs with cruise speeds of 20-25 knots that have built-in skimming troughs and cargo tanks, outrigger skimming arms, navigation and communication equipment.

In addition to being a member of CGA, the Company has contracted with Wild Well Control for source control at the wellhead, if required. Wild Well Control is one of the world's leading providers of firefighting, well control, engineering, and training services.

Safety and Environmental Management System. The Company has developed and implemented a Safety and Environmental Management System ("SEMS") to address oil and gas operations in the Outer Continental Shelf ("OCS"), as required by the Bureau of Safety and Environmental Enforcement ("BSEE"). Full implementation of the following thirteen mandatory elements of the American Petroleum Institute's Recommended Practice 75 (API RP 75) was required on or before November 15, 2011:

- General provisions
- Safety and environmental information
- Hazards analyses
- Management of change
- Operating procedures
- Safe work practices
- Training
- Mechanical integrity
- Pre-startup review
- Emergency response and control
- Investigation of accidents
- Audits
- Records and documentation

Our SEMS program identifies, addresses, and manages safety, environmental hazards, and its impacts during the design, construction, start-up, operation, inspection, and maintenance of all new and existing facilities. The Company has established goals, performance measures, training, accountability for its implementation, and provides necessary resources for an effective SEMS, as well as reviews the adequacy and effectiveness of the SEMS program. Facilities must be designed, constructed, maintained, monitored, and operated in a manner compatible with industry codes, consensus standards, and all applicable governmental regulations. We have contracted with Island Technologies Inc. to manage our SEMS program for production operations.

The BSEE will enforce the SEMS requirements through audits. We must have our SEMS program audited by either an independent third-party or our designated and qualified personnel within 2 years of the initial implementation and at least once

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every 3 years thereafter. Failure of an audit may force us to shut-in our Gulf of Mexico operations.

Employees

We have ten employees, all of whom are full time. The Company outsources its human resources function to Insperity, Inc. and all of the Company's employees are co-employees of Insperity, Inc. In addition to our employees, we use the services of independent consultants and contractors to perform various professional services, including reservoir engineering, land, legal, environmental and tax services. We are dependent on JEX for prospect generation, evaluation and prospect leasing. As a working interest owner, we rely on outside operators to drill, produce and market our natural gas and oil for our onshore prospects and certain offshore prospects where we are a non-operator. In the offshore prospects where we are the operator, we currently rely on a turn-key contractor to drill and rely on independent contractors to produce and market our natural gas and oil. In addition, we utilize the services of independent contractors to perform field and on-site drilling and production operation services and independent third party engineering firms to calculate our reserves.

Directors and Executive Officers

The following table sets forth the names, ages and positions of our directors and executive officers:

Name	Age	Position
Kenneth R. Peak	67	Chairman and Director
Brad Juneau	52	President, Acting Chief Executive Officer and Director
Sergio Castro	43	Vice President, Chief Financial Officer, Treasurer and Secretary
Yaroslava Makalskaya	43	Vice President, Controller and Chief Accounting Officer
Marc L. Duncan	59	Vice Chairman of Operating Committee; Safety, Environmental and Regulatory Compliance Officer (SEARCO)
Charles A. Cambron	45	Vice President - Drilling
Michael J. Autin	53	Vice President - Production
B.A. Berilgen	64	Director
Jay D. Brehmer	47	Director
Charles M. Reimer	67	Director
Steven L. Schoonover	67	Director

Kenneth R. Peak. Mr. Peak is the founder of the Company and has been Chairman and Chief Executive Officer since its formation in September 1999. In August 2012, Mr. Peak received a medical leave of absence from the Company for up to six months and Mr. Juneau was elected President and Acting Chief Executive Officer. Mr. Peak entered the energy industry in 1973 as a commercial banker and held a variety of financial and executive positions in the oil and gas industry prior to starting Contango in 1999. Mr. Peak served as an officer in the U.S. Navy from 1968 to 1971. Mr. Peak received a BS in physics from Ohio University in 1967, and an MBA from Columbia University in 1972. He currently serves as a director of Patterson-UTI Energy, Inc., a provider of onshore contract drilling services to exploration and production companies in North America, and Contango ORE, Inc., an exploration stage company involved in the exploration of gold and associated minerals and rare earth elements in the state of Alaska.

Brad Juneau. Mr. Juneau was elected a director of Contango in April 2012 and President and Acting Chief Executive Officer in August 2012. Mr. Juneau is the sole manager of the general partner of JEX, a company involved in the generation of natural gas and oil prospects. Prior to forming Juneau Exploration in 1998, Mr. Juneau served as senior vice president of exploration for Zilkha Energy Company from 1987 to 1998. Prior to joining Zilkha Energy Company, Mr. Juneau served as staff petroleum engineer with Texas International Company for three years, where his principal responsibilities included reservoir engineering, as well as acquisitions and evaluations. Prior to that, he was a production engineer with Enserch Corporation in Oklahoma City. Mr. Juneau holds a BS degree in petroleum engineering from Louisiana State University. Mr. Juneau was also elected President, Acting Chief Executive Officer and director of Contango ORE, Inc. in August 2012.

Sergio Castro. Mr. Castro joined Contango in March 2006 as Treasurer and was appointed Vice President, Treasurer and Secretary in April 2006 and Chief Financial Officer in June 2010. Prior to joining Contango, Mr. Castro spent two years (April 2004 to March 2006) as a consultant for UHY Advisors TX, LP. From January 2001 to April 2004, Mr. Castro was a lead credit analyst for Dynegy Inc. From August 1997 to January 2001, Mr. Castro worked as an auditor for Arthur Andersen LLP, where he specialized in energy companies. Mr. Castro was honorably discharged from the U.S. Navy in 1993 as an E-6, where he served onboard a nuclear powered submarine. Mr. Castro received a BBA in Accounting in 1997 from the University of Houston, graduating summa cum laude. Mr. Castro is a CPA and a Certified Fraud Examiner.

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Yaroslava Makalskaya. Ms. Makalskaya joined Contango in March 2010 and was appointed Vice President, Controller and Chief Accounting Officer in June 2010. Ms. Makalskaya has approximately 20 years of experience in accounting and finance, including 13 years in public accounting. Prior to joining Contango, Ms. Makalskaya was a director in the Transaction Services practice at PricewaterhouseCoopers, where she assisted clients with M&A transactions as well as advised clients with complex accounting and financial reporting issues. Prior to July 2008 Ms. Makalskaya was a Senior Manager in the audit practices of PricewaterhouseCoopers and Arthur Andersen, where her clients included many US and international companies in energy, utilities, mining and other sectors. Ms. Makalskaya holds a MS degree in Economics from Novosibirsk State University in Russia. Ms. Makalskaya is a CPA.
Marc L. Duncan. Mr. Duncan joined Contango in June 2005 as President and Chief Operating Officer of Contango Operators, Inc. and was appointed President and Chief Operating Officer of Contango Oil & Gas Company in October 2006 until December 2010. In December 2010 Mr. Duncan was appointed as the Company’s Safety, Environmental and Regulatory Compliance Officer (“SEARCO”) and Vice Chairman of the Operating Committee. Mr. Duncan has over 38 years of experience in the energy industry and has held a variety of domestic and international engineering and senior-level operations management positions relating to natural gas and oil exploration, project development, and drilling and production operations. Prior to joining Contango, Mr. Duncan served as Chief Operating Officer of USENCO International, Inc. and its subsidiaries and affiliates in China and Ukraine from February 2000 to July 2004 and as a senior project and drilling engineer for Hunt Oil Company from July 2004 to June 2005. He holds an MBA in Engineering Management from the University of Dallas, an MEd from the University of North Texas and a BS in Science and Education from Stephen F. Austin University.
Charles A. Cambron. Mr. Cambron joined Contango in August 2010 as Vice President of Drilling. Mr. Cambron has over 20 years of experience in the Gulf of Mexico oil and gas industry. Most recently he was employed by Applied Drilling Technology, Inc. (ADTI) as an Operations Manager from August 1995 until August 2010. He also held various positions in engineering and offshore supervision over a 15 year period. Prior to ADTI, Mr. Cambron began his career with Rowan Petroleum, Inc. as a Drilling Engineer working in both the Gulf of Mexico and North Sea. Mr. Cambron received a BS degree in Petroleum Engineering from the University of Oklahoma in 1991.
Michael J. Autin. Mr. Autin joined Contango in May 2012 as Vice President of Production in August 2012. Mr. Autin has over 33 years of experience in the petroleum industry including the Gulf of Mexico and U.S onshore shale. He has held various positions including Production Manager, HSE Manager and Offshore Installation Manager. Prior to joining Contango, Mr. Autin was employed by BHP Billiton since October 2000, where most recently he was Gulf of Mexico Operations Manager, Field Manager and Operations Advisor. Mr. Autin attended Nicholls State University where he studied petroleum, safety and business. He received a BS degree in 1986.
B.A. Berilgen. Mr. Berilgen was appointed a director of Contango in July 2007. Mr. Berilgen has served in a variety of senior positions during his 40 year career. Most recently, he became Chief Executive Officer of Patara Oil & Gas LLC in April 2008. Prior to that he was Chairman, Chief Executive Officer and President of Rosetta Resources Inc., a company he founded in June 2005, until his resignation in July 2007, and then he was an independent consultant from July 2007 through April 2008. Mr. Berilgen was also previously the Executive Vice President of Calpine Corp. and President of Calpine Natural Gas L.P. from October 1999 through June 2005. In June 1997, Mr. Berilgen joined Sheridan Energy, a public oil and gas company, as its President and Chief Executive Officer. Mr. Berilgen attended the University of Oklahoma, receiving a BS in Petroleum Engineering in 1970 and a MS in Industrial Engineering / Management Science.
Jay D. Brehmer. Mr. Brehmer has been a director of Contango since October 2000. Mr. Brehmer is a co-founding partner of Southplace, LLC, a provider of private-company middle-market corporate finance advisory services.
Mr. Brehmer founded Southplace, LLC in November 2002. In August 2004, Mr. Brehmer became Managing Director of Houston Capital Advisors LP, a boutique financial advisory, merger and acquisition investment bank, while still retaining his membership in Southplace, LLC. Mr. Brehmer resigned from Houston Capital Advisors LP in January 2008 and is currently associated with Southplace, LLC in a full-time capacity. From May 1998 until November 2002, Mr. Brehmer was responsible for structured-finance energy related transactions at Aquila Energy Capital Corporation. Prior to joining Aquila, Mr. Brehmer founded Capital Financial Services, which provided mid-cap companies with

strategic merger and acquisition advice coupled with prudent financial capitalization structures. Mr. Brehmer holds a BBA from Drake University in Des Moines, Iowa.

Charles M. Reimer. Mr. Reimer was elected a director of Contango in November 2005. Mr. Reimer is President of Freeport LNG Development, L.P., and has experience in exploration, production, liquefied natural gas (“LNG”) and business development ventures, both domestically and abroad. From 1986 until 1998, Mr. Reimer served as the senior executive responsible for the VICO joint venture that operated in Indonesia, and provided LNG technical support to P. T. Badak. Additionally, during these years he served, along with Pertamina executives, on the board of directors of the P.T. Badak LNG plant in Bontang, Indonesia. Mr. Reimer began his career with Exxon Company USA in 1967 and held various professional and management positions in Texas and Louisiana. Mr. Reimer was named President of Phoenix Resources Company in 1985 and

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relocated to Cairo, Egypt, to begin eight years of international assignments in both Egypt and Indonesia. Prior to joining Freeport LNG Development, L.P. in December 2002, Mr. Reimer was President and Chief Executive Officer of Cheniere Energy, Inc.

Steven L. Schoonover. Mr. Schoonover was elected a director of Contango in November 2005. Mr. Schoonover was most recently Chief Executive Officer of Cellxion, L.L.C., a company he founded in September 1996 and sold in September 2007, which specialized in construction and installation of telecommunication buildings and towers, as well as the installation of high-tech telecommunication equipment. Since the sale in September 2007, Mr. Schoonover continues to serve as a consultant to the current management team of Cellxion, L.L.C. From 1990 until its sale in November 1997 to Telephone Data Systems, Inc., Mr. Schoonover served as President of Blue Ridge Cellular, Inc., a full-service cellular telephone company he co-founded. From 1983 to 1996, he served in various positions, including President and Chief Executive Officer, with Fibrebond Corporation, a construction firm involved in cellular telecommunications buildings, site development and tower construction. Mr. Schoonover has been awarded, on two occasions with two different companies, Entrepreneur of the Year, sponsored by Ernst & Young, Inc Magazine and USA Today.

Directors of Contango serve as members of the board of directors until the next annual stockholders meeting, until successors are elected and qualified or until their earlier resignation or removal. Officers of Contango are elected by the board of directors and hold office until their successors are chosen and qualified, until their death or until they resign or have been removed from office. All corporate officers serve at the discretion of the board of directors.

Beginning December 1, 2011, each non-employee director of the Company received a quarterly retainer of $28,000 payable in cash, with no stock option or common stock grants. There were no additional payments for meetings attended or being chairman of a committee. During fiscal year 2011 and 2010, each outside director of the Company received a quarterly retainer of $20,000 payable in cash, with no stock option or common stock grants. There were no additional payments for meetings attended or being chairman of a committee. There are no family relationships between any of our directors or executive officers.

Corporate Offices

We lease our corporate offices at 3700 Buffalo Speedway, Suite 960, Houston, Texas 77098. In November 2010, the Company expanded its office space and extended its office lease agreement through December 31, 2015.

Code of Ethics

We adopted a Code of Ethics for senior management in December 2002, which was updated and adopted by the Company's Board of Directors in May 2012. A copy of our Code of Ethics is filed as an exhibit to this Form 10-K and is also available on our website at www.contango.com.

Available Information

You may read and copy all or any portion of this annual report on Form 10-K, our quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, without charge at the office of the Securities and Exchange Commission (the “SEC”) in Public Reference Room, 100 F Street NE, Washington, DC, 20549. Information regarding the operation of the public reference rooms may be obtained by calling the SEC at 1-800-SEC-0330. In addition, filings made with the SEC electronically are publicly available through the SEC's website at http://www.sec.gov, and at our website at http://www.contango.com. This annual report on Form 10-K, including all exhibits and amendments, has been filed electronically with the SEC.

Item 1A. Risk Factors

In addition to the other information set forth elsewhere in this Form 10-K, you should carefully consider the following factors when evaluating the Company. An investment in the Company is subject to risks inherent in our business. The trading price of the shares of the Company is affected by the performance of our business relative to, among other things, competition, market conditions and general economic and industry conditions. The value of an investment in the Company may decrease, resulting in a loss.

We have no ability to control the market price for natural gas and oil. Natural gas and oil prices fluctuate widely, and a substantial or extended decline in natural gas and oil prices would adversely affect our revenues, profitability and growth and could have a material adverse effect on the business, the results of operations and financial condition of the Company.

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Our revenues, profitability and future growth depend significantly on natural gas and crude oil prices. Prices received affect the amount of future cash flow available for capital expenditures and repayment of indebtedness and our ability to raise additional capital. We do not expect to hedge our production to protect against price decreases. Lower prices may also affect the amount of natural gas and oil that we can economically produce. Factors that can cause price fluctuations include:

• Overall economic conditions.
• The domestic and foreign supply of natural gas and oil.
• The level of consumer product demand.
• Adverse weather conditions and natural disasters.
• The price and availability of competitive fuels such as LNG, heating oil and coal.
• Political conditions in the Middle East and other natural gas and oil producing regions.
• The level of LNG imports and any LNG exports.
• Domestic and foreign governmental regulations.
• Special taxes on production.
• Access to pipelines and gas processing plants.
• The loss of tax credits and deductions.

A substantial or extended decline in natural gas and oil prices could have a material adverse effect on our access to capital and the quantities of natural gas and oil that may be economically produced by us. A significant decrease in price levels for an extended period would negatively affect us.

We depend on the services of our Chairman and implementation of our business plan could be seriously harmed if we lost his services.

We depend heavily on the services of Mr. Kenneth R. Peak, our Chairman, who received a medical leave of absence from the Company for up to six months in August 2012. The proceeds from a $10.0 million "key person" life insurance policy on Mr. Peak may not be adequate to cover our losses in the event of Mr. Peak's death.

We are highly dependent on the technical services provided by JEX and could be seriously harmed if JEX terminated its services with us or became otherwise unavailable.

Because we employ no geoscientists, we are dependent upon JEX for the success of our natural gas and oil exploration projects and expect to remain so for the foreseeable future. We have entered into an Advisory Agreement with JEX, whereby in addition to generating and evaluating offshore and onshore exploration prospects for the Company, JEX will direct Contango's staff on operational matters including drilling, completions and production. The Advisory Agreement is effective for a term of two years from April 1, 2012, and continues on a month-to-month basis thereafter. In August 2012, Mr. Brad Juneau was elected President and Acting Chief Executive Officer during Mr. Peak's medical leave of absence. Highly qualified explorationists and engineers are difficult to attract and retain. As a result, the loss of the services of JEX could have a material adverse effect on us and could prevent us from pursuing our business plan. Additionally, the loss by JEX of certain explorationists could have a material adverse effect on our operations as well.

Our ability to successfully execute our business plan is dependent on our ability to obtain adequate financing.

Our business plan, which includes participation in 3-D seismic shoots, lease acquisitions, the drilling of exploration prospects and producing property acquisitions, has required and is expected to continue to require substantial capital expenditures. We may require additional financing to fund our planned growth. Our ability to raise additional capital will depend on the results of our operations and the status of various capital and industry markets at the time we seek such capital. Accordingly, additional financing may not be available to us on acceptable terms, if at all. In the event additional capital resources are unavailable, we may be required to curtail our exploration and development activities or be forced to sell some of our assets in an untimely fashion or on less than favorable terms.

It is difficult to quantify the amount of financing we may need to fund our planned growth. The amount of funding we may need in the future depends on various factors such as:

• Our financial condition.
• The prevailing market price of natural gas and oil.
• The type of projects in which we are engaging.
• The lead time required to bring any discoveries to production.

We frequently obtain capital through the sale of our producing properties.

The Company, since its inception in September 1999, has raised approximately $524 million from various property sales. These sales bring forward future revenues and cash flows, but our longer term liquidity could be impaired to the extent our exploration efforts are not successful in generating new discoveries, production, revenues and cash flows. Additionally, our longer term liquidity could be impaired due to the decrease in our inventory of producing properties that could be sold in future periods. Further, as a result of these property sales the Company's ability to collateralize bank borrowings is reduced which increases our dependence on more expensive mezzanine debt and potential equity sales. The availability of such funds will depend upon prevailing market conditions and other factors over which we have no control, as well as our financial condition and results of operations.

We assume additional risk as operator in drilling high pressure and high temperature wells in the Gulf of Mexico.

COI, a wholly-owned subsidiary of the Company, was formed for the purpose of drilling and operating exploration wells in the Gulf of Mexico. Drilling activities are subject to numerous risks, including the significant risk that no commercially productive hydrocarbon reserves will be encountered. The cost of drilling, completing and operating wells and of installing production facilities and pipelines is often uncertain. Drilling costs could be significantly higher if we encounter difficulty in drilling offshore exploration wells. The Company's drilling operations may be curtailed, delayed, canceled or negatively impacted as a result of numerous factors, including title problems, weather conditions, compliance with governmental requirements and shortages or delays in the delivery or availability of material, equipment and fabrication yards. In periods of increased drilling activity resulting from high commodity prices, demand exceeds availability for drilling rigs,
drilling vessels, supply boats and personnel experienced in the oil and gas industry in general, and the offshore oil and gas industry in particular. This may lead to difficulty and delays in consistently obtaining certain services and equipment from vendors, obtaining drilling rigs and other equipment at favorable rates and scheduling equipment fabrication at factories and fabrication yards. This, in turn, may lead to projects being delayed or experiencing increased costs. The cost of drilling, completing, and operating wells is often uncertain, and new wells may not be productive or we may not recover all or any of our investment. The risk of significant cost overruns, curtailments, delays, inability to reach our target reservoir and other factors detrimental to drilling and completion operations may be higher due to our inexperience as an operator.

Additionally, we use turnkey contracts that may cost more than non-turnkey drilling contracts at daily rates. Should our contracts come off turnkey or should such turnkey contracts be terminated by the turnkey drilling contractor, our drilling costs could be significantly higher.

We rely on third-party operators to operate and maintain some of our production platforms, pipelines and processing facilities and, as a result, we have limited control over the operations of such facilities. The interests of an operator may differ from our interests.

We depend upon the services of third-party operators to operate production platforms, pipelines, gas processing facilities and the infrastructure required to produce and market our natural gas, condensate and oil. We have limited influence over the conduct of operations by third-party operators. As a result, we have little control over how frequently and how long our production is shut-in when production problems, weather and other production shut-ins occur. Poor performance on the part of, or errors or accidents attributable to, the operator of a project in which we participate may have an adverse effect on our results of operations and financial condition. Also, the interest of an operator may differ from our interests.

Repeated production shut-ins can possibly damage our well bores.

Our well bores are required to be shut-in from time to time due to a variety of issues, including a combination of weather, mechanical problems, sand production, bottom sediment, water and paraffin associated with our condensate production at our Eugene Island 11 platform, as well as downstream third-party facility and pipeline shut-ins. In addition, shut-ins are necessary from time to time to upgrade and improve the production handling capacity at related downstream platform, gas processing and pipeline infrastructure. In addition to negatively impacting our near term revenues and cash flow, repeated production shut-ins may damage our well bores if repeated excessively or not executed properly. The loss of a well bore due to damage could require us to drill additional wells.

Concentrating our capital investment in the Gulf of Mexico increases our exposure to risk.

The vast majority of our capital investments is primarily focused in offshore Gulf of Mexico exploration prospects, which may result in a total loss of our investment. Furthermore, even our productive wells may not result in profitable operations. Gulf of Mexico exploration efforts have been undertaken for over 60 years and remaining prospects are at deeper horizons that are more expensive to drill and often in much deeper water depths. Accordingly, as a result, a number of companies have shifted their focus to onshore “shale plays.” The Company’s continuing focus on the Gulf of Mexico will result in significant dry hole costs, perhaps in excess of $30 million for one well, which significantly concentrates and increases our risk profile.

Natural gas and oil reserves are depleting assets and the failure to replace our reserves would adversely affect our production and cash flows.

Our future natural gas and oil production depends on our success in finding or acquiring new reserves. If we fail to replace reserves, our level of production and cash flows will be adversely impacted. Production from natural gas and oil properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves will decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Further, the majority of our reserves are proved developed producing. Accordingly, we do not have significant opportunities to increase our production from our existing proved reserves. Our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and oil reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. If we are not successful, our future production and revenues will be adversely affected.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities of our reserves.

There are numerous uncertainties in estimating crude oil and natural gas reserves and their value, including many factors that are beyond our control. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities of reserves shown in this report.

In order to prepare these estimates, our independent third-party petroleum engineers must project production rates and timing of development expenditures as well as analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions relating to matters such as natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and pre-tax net present value of reserves shown in a reserve report. In addition, estimates of our proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control and may prove to be incorrect over time. As a result, our estimates may require substantial upward or downward revisions if subsequent drilling, testing and production reveal different results. Furthermore, some of the producing wells included in our reserve report have produced for a relatively short period of time. Accordingly, some of our reserve estimates are not based on a multi-year production decline curve and are calculated using a reservoir simulation model together with volumetric analysis. Any downward adjustment could indicate lower future production and thus adversely affect our financial condition, future prospects and market value.

The Company’s reserves and revenues are primarily concentrated in one field.

Approximately 82% of our reserves are assigned to our Dutch and Mary Rose discoveries which have ten producing well bores concentrated in one reservoir on one field, and are producing through two production platforms. Reserve assessments based on only ten well bores in one reservoir are subject to significantly greater risk of being shut-in for a variety of weather, platform and pipeline difficulties. In addition, the risk of a downward revision in our reserve estimates is also greater.

We rely on the accuracy of the estimates in the reservoir engineering reports provided to us by our outside engineer.

We have no in house reservoir engineering capability, and therefore rely on the accuracy of the periodic reservoir reports provided to us by our independent third-party reservoir engineer. If those reports prove to be inaccurate, our financial reports could have material misstatements. Further, we use the reports of our independent reservoir engineer in our financial planning. If the reports of the outside reservoir engineer prove to be inaccurate, we may make misjudgments in our financial planning.

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Exploration is a high risk activity, and our participation in drilling activities may not be successful.

Our future success largely depends on the success of our exploration drilling program. Participation in exploration drilling activities involves numerous risks, including the significant risk that no commercially productive natural gas or oil reservoirs will be discovered. The cost of drilling, completing and operating wells is uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- Unexpected drilling conditions.
- Blowouts, fires or explosions with resultant injury, death or environmental damage.
- Pressure, temperature or other irregularities in formations.
- Equipment failures and/or accidents caused by human error.
- Tropical storms, hurricanes and other adverse weather conditions.
- Compliance with governmental requirements and laws, present and future.
- Shortages or delays in the availability of drilling rigs and the delivery of equipment.
- Our turnkey drilling contracts reverting to a day rate contract or our turnkey contractor electing to terminate the turnkey contract would significantly increase the cost and risk to the Company.
- Problems at third-party operated platforms, pipelines and gas processing facilities over which we have no control.

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. Poor results from our drilling activities would materially and adversely affect our future cash flows and results of operations. In addition, as a “successful efforts” company, we choose to account for unsuccessful exploration efforts (the drilling of “dry holes”) and seismic costs as a current expense of operations, which immediately impacts our earnings. Significant expensed exploration charges in any period would materially adversely affect our earnings for that period and cause our earnings to be volatile from period to period.

Production activities in the Gulf of Mexico increase our susceptibility to pollution and natural resource damage.

A blowout, rupture or spill of any magnitude would present serious operational and financial challenges. All of the Company’s operations in the Gulf of Mexico shelf are in water depths of less than 200 feet and less than 50 miles from the coast. Such proximity to the shore-line increases the probability of a biological impact or damaging the fragile eco-system in the event of released condensate.

Possible regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural gas.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth’s atmosphere. In response to these studies, governments have begun adopting domestic and international climate change regulations that require reporting and reductions in the emission of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several countries including countries in the European Union have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs or have begun considering adopting greenhouse gas regulatory programs.

The Environmental Protection Agency (the "EPA") has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and require reporting by regulated facilities by March 2011 and annually thereafter. In November 2010, the EPA issued a final rule requiring companies to report certain greenhouse gas emissions from oil and natural gas facilities. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding serves as a first step to issuing regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. EPA has proposed such greenhouse gas regulations and may issue final rules at a subsequent date.

Several decisions have been issued by courts that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur increased operating and compliance costs, and could have an adverse effect on demand for the natural gas and condensate that we produce.

The natural gas and oil business involves many operating risks that can cause substantial losses and our insurance coverage may not be sufficient to cover some liabilities or losses that we may incur.

The natural gas and oil business involves a variety of operating risks, including:

• Blowouts, fires and explosions.
• Surface cratering.
• Uncontrollable flows of underground natural gas, oil or formation water.
• Natural disasters.
• Pipe and cement failures.
• Casing collapses.
• Stuck drilling and service tools.
• Reservoir compaction.
• Abnormal pressure formations.
• Environmental hazards such as natural gas leaks, oil spills, pipeline ruptures or discharges of toxic gases.
• Capacity constraints, equipment malfunctions and other problems at third-party operated platforms, pipelines and gas processing plants over which we have no control.
• Repeated shut-ins of our well bores could significantly damage our well bores.
• Required workovers of existing wells that may not be successful.

If any of the above events occur, we could incur substantial losses as a result of:

• Injury or loss of life.
• Reservoir damage.
• Severe damage to and destruction of property or equipment.
• Pollution and other environmental damage.
• Clean-up responsibilities.
• Regulatory investigations and penalties.
• Suspension of our operations or repairs necessary to resume operations.

Offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as capsizing and collisions. In addition, offshore operations, and in some instances, operations along the Gulf Coast, are subject to damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce the funds available for exploration, development or leasehold acquisitions, or result in loss of properties.

If we were to experience any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, any one of which could adversely affect our ability to conduct operations. In accordance with customary industry practices, we maintain insurance against some, but not all, of these risks. Losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. We may not be able to maintain adequate insurance in the future at rates we consider reasonable, and particular types of coverage may not be available. An event that is not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

Not hedging our production may result in losses.

Due to the significant volatility in natural gas prices and the potential risk of significant hedging losses if our production should be shut-in during a period when NYMEX natural gas prices increase, our policy is to hedge only through the purchase of puts. By not hedging our production, we may be more adversely affected by declines in natural gas and oil prices than our competitors who engage in hedging arrangements.

Our ability to market our natural gas and oil may be impaired by capacity constraints and equipment malfunctions on the platforms, gathering systems, pipelines and gas plants that transport and process our natural gas and oil.

All of our natural gas and oil is transported through gathering systems, pipelines and processing plants. Transportation capacity on gathering system pipelines and platforms is occasionally limited and at times unavailable due to repairs or improvements being made to these facilities or due to capacity being utilized by other natural gas or oil shippers that may have priority transportation agreements. If the gathering systems, processing plants, platforms or our transportation capacity is materially restricted or is unavailable in the future, our ability to market our natural gas or oil could be impaired and cash flow from the affected properties could be reduced, which could have a material adverse effect on our financial condition and results of operations. Further, repeated shut-ins of our wells could result in damage to our well bores that would impair our ability to produce from these wells and could result in additional wells being required to produce our reserves.

We may not have title to our leased interests and if any lease is later rendered invalid, we may not be able to proceed with our exploration and development of the lease site.

Our practice in acquiring exploration leases or undivided interests in natural gas and oil leases is to not incur the expense of retaining title lawyers to examine the title to the mineral interest prior to executing the lease. Instead, we rely upon the judgment of JEX and others to perform the field work in examining records in the appropriate governmental, county or parish clerk’s office before leasing a specific mineral interest. This practice is widely followed in the industry. Prior to the drilling of an exploration well the operator of the well will typically obtain a preliminary title review of the drillsite lease and/or spacing unit within which the proposed well is to be drilled to identify any obvious deficiencies in title to the well and, if there are deficiencies, to identify measures necessary to cure those defects to the extent reasonably possible. However, such deficiencies may not have been cured by the operator of such wells. It does happen, from time to time, that the examination made by title lawyers reveals that the lease or leases are invalid, having been purchased in error from a person who is not the rightful owner of the mineral interest desired. In these circumstances, we may not be able to proceed with our exploration and development of the lease site or may incur costs to remedy a defect. It may also happen, from time to time, that the operator may elect to proceed with a well despite defects to the title identified in the preliminary title opinion.

Competition in the natural gas and oil industry is intense, and we are smaller and have a more limited operating history than many of our competitors.

We compete with a broad range of natural gas and oil companies in our exploration and property acquisition activities. We also compete for the equipment and labor required to operate and to develop these properties. Many of our competitors have substantially greater financial resources than we do. These competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties. Further, they may be able to evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and oil and to acquire additional properties in the future depends on our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, many of our competitors have been operating for a much longer time than we have and have substantially larger staffs. We may not be able to compete effectively with these companies or in such a highly competitive environment.

Proposed United States federal budgets and pending legislation contain certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

In February 2009, the US federal administration released its budget proposals for 2010, which included numerous proposed tax changes. In April 2009, legislation was introduced to further these objectives and in February 2010, the federal administration released similar budget proposals for 2011. The proposed budgets and legislation would repeal many tax incentives and deductions that are currently used by oil and gas companies in the United States and impose new taxes. Among others, the provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; repeal of the percentage depletion deduction for oil and gas properties; repeal of the manufacturing tax deduction for oil and gas companies; increase in the geological and geophysical amortization period for independent producers; and implementation of a fee on non-producing leases located on federal lands. Should some or all of these provisions become law, taxes on the E&P industry would increase, which could have a negative impact on our results of operations and cash flows. Although these proposals initially were made in 2009, none have become law. It is still, however, the federal administration's stated intention to enact legislation to repeal tax incentives and deductions and impose new taxes on oil and gas companies.

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We are subject to complex laws and regulations, including environmental regulations that can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to numerous laws and regulations governing the operation and maintenance of our facilities and the discharge of materials into the environment. Failure to comply with such rules and regulations could result in substantial penalties and have an adverse effect on us. These laws and regulations:

- Require that we obtain permits before commencing drilling.
- Restrict the substances that can be released into the environment in connection with drilling and production activities.
- Limit or prohibit drilling activities on protected areas, such as wetlands or wilderness areas.
- Require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells.

Under these laws and regulations, we could be liable for personal injury and clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. We maintain only limited insurance coverage for sudden and accidental environmental damages. Accordingly, we may be subject to liability, or we may be required to cease production from properties in the event of environmental damages. These laws and regulations have been changed frequently in the past. In general, these changes have imposed more stringent requirements that increase operating costs or require capital expenditures in order to remain in compliance. It is also possible that unanticipated developments could cause us to make environmental expenditures that are significantly different from those we currently expect. Existing laws and regulations could be changed and any such changes could have an adverse effect on our business and results of operations.

Our operations in the Gulf of Mexico have been and may continue to be adversely affected by changes in laws and regulations which have occurred and are expected to continue to occur as a result of the Deepwater Horizon Incident.

In April 2010, the deepwater Gulf of Mexico drilling rig Deepwater Horizon was engaged in drilling operations for another operator and sank after an apparent blowout and fire. The accident resulted in the loss of life and a significant oil spill. As a result, the Department of the Interior issued additional safety and performance standards as well as rigorous monitoring and testing requirements for offshore drilling. In addition, various Congressional committees began pursuing legislation to regulate drilling activities, establish safety requirements and increase liability for oil spills.

We continue to monitor legislative and regulatory developments, including the Drilling Safety Rule and the Workforce Safety Rule issued by the Department of the Interior. However, the full legislative and regulatory response to the incident is not fully known. An expansion of safety and performance regulations or an increase in liability for drilling activities will have one or more of the following impacts on our business:

- Increase the costs of drilling exploratory and development wells.
- Cause delays in, or preclude, the development of projects in the Gulf of Mexico.
- Result in longer time periods to obtain permits.
- Result in higher operating costs.
- Increase or remove liability caps for claims of damages from oil spills.
- Limit our ability to obtain additional insurance coverage on commercially reasonable terms to protect against any increase in liability.

Any of the above factors may result in a reduction of our cash flows, profitability, and the fair value of our properties.

New regulatory requirements and permitting procedures have significantly delayed our ability to obtain permits to drill new wells in offshore waters.

Subsequent to the Deepwater Horizon Incident in the Gulf of Mexico, a series of Notices to Lessees ("NTLs") were issued which imposed new regulatory requirements and permitting procedures for new wells to be drilled in federal waters of the OCS. These new regulatory requirements include the following:

- The Environmental NTL, which imposes new and more stringent requirements for documenting the environmental impacts potentially associated with the drilling of a new offshore well and significantly increases oil spill response requirements.
- The Compliance and Review NTL, which imposes requirements for operators to secure independent reviews of well design, construction and flow intervention processes, and also requires certifications of compliance from senior corporate officers.

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- The Drilling Safety Rule, which prescribes tighter cementing and casing practices, imposes standards for the use of drilling fluids to maintain well bore integrity, and stiffens oversight requirements relating to blowout preventers and their components, including shear and pipe rams.
- The Workplace Safety Rule, which requires operators to have a comprehensive SEMS in order to reduce human and
- organizational errors as root causes of work-related accidents and offshore spills.

Since the adoption of these new regulatory requirements, BOEM has been taking much longer periods of time to review and approve permits for new wells. Due to the extremely slow pace of permit review and approval, the BOEM may now take four months or longer to approve applications for drilling permits that were previously approved in less than 30 days. The new rules also increase the cost of preparing each permit application and will increase the cost of each new well.

The BSEE has implemented much more stringent controls and reporting requirements that if not followed, could result in significant monetary penalties or a shut-in of all or a portion of our Gulf of Mexico operations.

The BSEE is the federal agency responsible for overseeing the safe and environmentally responsible development of energy and mineral resources on the OCS. They are responsible for leading the most aggressive and comprehensive reforms to offshore oil and gas regulation and oversight in U.S. history. Their reforms have tightened requirements for everything from well design and workplace safety to corporate accountability. One of the many reforms includes implementing a SEMS program. This program requires operators to identify, address, and manage safety and environmental hazards during the design, construction, start-up, operation, inspection, and maintenance of all new and existing facilities. Facilities must be designed, constructed, maintained, monitored, and operated in a manner compatible with industry codes, consensus standards, and all
applicable governmental regulations. Failure to comply with the SEMS program may force us to cease operations in the Gulf of Mexico.

Additionally, the OCS Lands Act authorizes and requires the BSEE to provide for both an annual scheduled inspection and a periodic unscheduled (unannounced) inspection of all oil and gas operations on the OCS. In addition to examining all safety equipment designed to prevent blowouts, fires, spills, or other major accidents, the inspections focus on pollution, drilling operations, completions, workovers, production, and pipeline safety. Upon detecting a violation, the inspector issues an Incident of Noncompliance ("INC") to the operator and uses one of two main enforcement actions (warning or shut-in), depending on the severity of the violation. If the violation is not severe or threatening, a warning INC is issued. The warning INC must be corrected within a reasonable amount of time specified on the INC. The shut-in INC may be for a single component (a portion of the facility) or the entire facility. The violation must be corrected before the operator is allowed to resume the activity in question.

In addition to the enforcement actions specified above, the BSEE can assess a civil penalty of up to $35,000 per violation per day if: 1) the operator fails to correct the violation in the reasonable amount of time specified on the INC; or 2) the violation resulted in a threat of serious harm or damage to human life or the environment. Operators with excessive INCs may be required to cease operations in the Gulf of Mexico.

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

It is customary in our industry to recover natural gas and oil from shale and other formations through the use of horizontal drilling combined with hydraulic fracturing. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in formations using water, sand and other additives pumped under high pressure into the formation. We intend to use hydraulic fracturing as a means to increase the productivity of the onshore wells that we drill and complete.

The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. Several states, including Pennsylvania, Texas, Colorado, Montana, New Mexico and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and/or well construction requirements on hydraulic fracturing operations. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

Additionally, the EPA has asserted federal regulatory authority over hydraulic fracturing activities involving diesel fuel (specifically, when diesel fuel is utilized in the stimulation fluid) under the Safe Drinking Water Act and is completing the process of drafting guidance documents related to this newly asserted regulatory authority. There are also certain governmental reviews either underway or being proposed that focus on shale and other formation completion and production practices, including hydraulic fracturing. Depending on the outcome of these studies, federal and state legislatures and agencies may seek

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to further regulate such activities. The EPA has published proposed New Source Performance Standards ("NSPS") and National Emissions Standards for Hazardous Air Pollutants ("NESHAP") that, if adopted as proposed, would amend existing NSPS and NESHAP standards for oil and gas facilities as well as create new NSPS standards for oil and gas production, transmission
and distribution facilities. The EPA has also proposed regulations focused on reducing emissions of certain air pollutants by the oil and gas industry, including volatile organic compounds, sulfur dioxide and certain air toxics.

Certain environmental and other groups have suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process. We cannot predict whether additional federal, state or local laws or regulations will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed through the adoption of new laws and regulations, our business and operations could be subject to delays, increased operating and compliance costs and process prohibitions.

We do not control the activities on properties we do not operate.

Other companies may from time to time drill, complete and operate properties in which we have an interest. As a result, we have a limited ability to exercise influence over operations for these properties or their associated costs. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors that are outside of our control, including:

- Timing and amount of capital expenditures.
- The operator’s expertise and financial resources.
- Approval of other participants in drilling wells.
- Selection of technology.

We are highly dependent on our management team, JEX, our exploration partners and third-party consultants and engineers, and any failure to retain the services of such parties could adversely affect our ability to effectively manage our overall operations or successfully execute current or future business strategies.

The successful implementation of our business strategy and handling of other issues integral to the fulfillment of our business strategy is highly dependent on our management team, as well as certain key geoscientists, geologists, engineers and other professionals engaged by us. We are highly dependent on the services provided by JEX. The loss of key members of our management team, JEX or other highly qualified technical professionals could adversely affect our ability to effectively manage our overall operations or successfully execute current or future business strategies which may have a material adverse effect on our business, financial condition and operating results.

Acquisition prospects are difficult to assess and may pose additional risks to our operations.

We expect to evaluate and, where appropriate, pursue acquisition opportunities on terms our management considers favorable. The successful acquisition of natural gas and oil properties requires an assessment of:

- Recoverable reserves.
- Exploration potential.
- Future natural gas and oil prices.
- Operating costs.

• Potential environmental and other liabilities and other factors.
• Permitting and other environmental authorizations required for our operations.

In connection with such an assessment, we would expect to perform a review of the subject properties that we believe to be generally consistent with industry practices. Nonetheless, the resulting conclusions are necessarily inexact and their accuracy inherently uncertain and such an assessment may not reveal all existing or potential problems, nor will it necessarily permit a buyer to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every platform or well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Future acquisitions could pose additional risks to our operations and financial results, including:

• Problems integrating the purchased operations, personnel or technologies.

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• Unanticipated costs.
• Diversion of resources and management attention from our exploration business.
• Entry into regions or markets in which we have limited or no prior experience.
• Potential loss of key employees of the acquired organization.

Low interest rates put us at a competitive disadvantage compared to our peers.

As of June 30, 2012, we had approximately $130 million in cash and no debt. The overnight T-bill investment rate for the fiscal year ended June 30, 2012 averaged approximately 0.035%, which would only generate investment income for the year of approximately $45,500. We therefore keep all of our cash in non-interest bearing accounts which are guaranteed by the U.S. Government. Competitive companies which borrow money are able to do so at extremely low rates and thereby may benefit from today's low level of interest rates.

Anti-takeover provisions of our certificate of incorporation, bylaws and Delaware law could adversely affect a potential acquisition by third-parties that may ultimately be in the financial interests of our stockholders.

Our Certificate of Incorporation, Bylaws and the Delaware General Corporation Law contain provisions that may discourage unsolicited takeover proposals. These provisions could have the effect of inhibiting fluctuations in the market price of our common stock that could result from actual or rumored takeover attempts, preventing changes in our management or limiting the price that investors may be willing to pay for shares of common stock.

Item 1B. Unresolved Staff Comments
None

Item 2. Properties

Development, Exploration and Acquisition Expenditures
The following table presents information regarding our net costs incurred in the purchase of proved and unproved properties and in exploration and development activities for the periods indicated:

	Year Ended June 30,		
	2012	2011	2010
Property acquisition costs:		(thousands)	
Unproved	$5,404	$2,802	$11,319
Proved	381	10,135	2,009
Exploration costs	1,154	14,016	52,805
Development costs	10,350	39,211	40,902
Total costs	$17,289	$66,164	$107,035

Drilling Activity
The following table shows our drilling activity for the periods indicated. The Company did not drill any wells during the fiscal year ended June 30, 2012. In the table, "gross" wells refer to wells in which we have a working interest, and "net" wells refer to gross wells multiplied by our working interest in such wells.

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	Year Ended June 30, 2012 Gross	Net	2011 Gross	Net	2010 Gross	Net
Exploratory Wells:						
Productive (onshore)	—	—	9	7.5	14	14.0
Productive (offshore)	—	—	1	1.0	2	1.3
Non-productive (onshore)	—	—	—	—	—	—
Non-productive (offshore)	—	—	1	1.0	2	2.0
Total	—	—	11	9.5	18	17.3

For the fiscal year ended June 30, 2011, of the nine productive onshore wells listed above, one relates to the Rexer-Tusa #2 well and eight relate to our Conterra Company wells. For the fiscal year ended June 30, 2010, of the 14 productive onshore wells listed above, one relates to our Rexer #1 well and 13 relate to our Conterra Company wells. The Rexer #1 well and Conterra Company wells were sold on May 13, 2011 while the sale of the Rexer-Tusa #2 was completed in October 2011. These wells are classified as discontinued operations in our financial statements for all periods presented.

Exploration and Development Acreage

Our principal natural gas and oil properties consist of natural gas and oil leases. The following table indicates our interests in developed and undeveloped acreage as of June 30, 2012:

	Developed Acreage (1)(2) Gross (4)	Net (5)	Undeveloped Acreage (1)(3) Gross (4)	Net (5)
Onshore (TMS)	—	—	13,848	13,848
Offshore Gulf of Mexico	21,949	13,242	26,283	22,653
Total	21,949	13,242	40,131	36,501

(1) Excludes any interest in acreage in which we have no working interest before payout or before initial production.
(2) Developed acreage consists of acres spaced or assignable to productive wells.
(3) Undeveloped acreage is considered to be those leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.
(4) Gross acres refer to the number of acres in which we own a working interest.
(5) Net acres represent the number of acres attributable to an owner's proportionate working interest in a lease (e.g., a 50% working interest in a lease covering 320 acres is equivalent to 160 net acres).

Included in the Offshore Gulf of Mexico acres shown in the table above are the beneficial interests Contango has in the offshore acreage owned by REX. The above table includes our 32.3% interest in REX's 1,788 net developed acres and 5,000 net undeveloped acres.

Productive Wells

The following table sets forth the number of gross and net productive natural gas and oil wells in which we owned an interest as of June 30, 2012:

	Total Productive Wells (1) Gross (2)	Net (3)
Natural gas (onshore)	—	—

Natural gas (offshore)	13	6.6
Oil	—	—
Total	13	6.6

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(1) Productive wells are producing wells and wells capable of producing commercial quantities. Completed but marginally producing wells are not considered here as a "productive" well.
(2) A gross well is a well in which we own an interest.
(3) The number of net wells is the sum of our fractional working interests owned in gross wells.

Natural Gas and Oil Reserves

The following table presents our estimated net proved natural gas and oil reserves and the pre-tax net present value of our reserves at June 30, 2012, based on reserve reports generated by William M. Cobb & Associates, Inc. ("Cobb"). The Company believes that having an independent and well respected third-party engineering firm prepare its reserve report enhances the credibility of its reported reserve estimates. Management is responsible for the reserve estimate disclosures in this filing, and meets regularly with our independent third-party engineer to review these reserve estimates. The qualifications of the technical person at Cobb responsible for overseeing the preparation of our reserve estimates are set forth below.

- Over 30 years of practical experience in the estimation and evaluation of reserves
- A registered professional engineer in the state of Texas
- Bachelor of Science Degree in Petroleum Engineering
- Member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers

Cobb has informed us that the technical person primarily responsible for the reserve estimates meets or exceeds the education, training, and experience requirements set forth in the standards pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in the application of industry standard practices to engineering evaluations as well as the application of SEC and other industry definitions and guidelines.

We maintain adequate and effective internal controls over the underlying data upon which reserves estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information, which is communicated to our reservoir engineers quarterly, is confirmed when our third-party reservoir engineers hold technical meetings with geologists, operations and land personnel to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and our own set of internal controls over financial reporting. Internal controls over financial reporting are assessed for effectiveness annually using criteria set forth in Internal Controls – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. All data such as commodity prices, lease operating expenses, production taxes, field level commodity price differentials, ownership percentages, and well production data are updated in the reserve database by our third-party reservoir engineers and then analyzed by management to ensure that they have been entered accurately and that all updates are complete. Once the reserve database has been entirely updated with current information, and all relevant technical support material has been assembled, our independent engineering firms prepare their independent reserve estimates and final report.

The following table sets forth our offshore proved reserves as of June 30, 2012:

	Developed	Undeveloped	Total
Natural gas (MMcf)	196,268	5,111	201,379
Oil and condensate (MBbls)	3,353	(41)	3,312
Natural gas liquids (MBbls)	5,664	222	5,886
Total proved reserves (MMcfe)	250,370	6,197	256,567

Pre-tax net present value, discounted at 10% (in thousands)	$686,900	$43,322	$730,222

Prior Year Reserves

Our estimated net proved natural gas, oil and natural gas liquids reserves as of June 30, 2009, 2010, 2011 and 2012 are disclosed on page F-24 and were based on reserve reports generated by William M. Cobb & Associates, Inc. (“Cobb”). The reserve estimates as of June 30, 2010 also include the reserves associated with the Joint Venture Assets which were prepared exclusively by Lonquist & Co. LLC (“Lonquist”). These Joint Venture Asset reserves account for approximately 8% of our total reserves as of June 30, 2010 and were sold on May 13, 2011. The technical person at Lonquist responsible for overseeing the preparation of our Joint Venture Asset reserve estimates had over 23 years of practical experience in the estimation and evaluation of reserves, is a registered professional engineer in the state of Texas, has a BS in Petroleum Engineering, and is a member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. This individual meets or exceeds the education, training, and experience requirements set forth in the standards pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in the application of industry standard practices to engineering evaluations as well as the application of SEC and other industry definitions and guidelines.

Proved Undeveloped Reserves

The Company annually reviews any proved undeveloped reserves (“PUDs”) to ensure their development within five years or less. As of June 30, 2012, the Company had approximately 6.2 Bcfe of PUDs related to Mary Rose #6, an acceleration well on state of Louisiana acreage. Our plan is to develop our PUD reserves prior to June 30, 2017. As of June 30, 2011, the Company had approximately 39 Bcfe of PUDs. Of this amount, approximately 37.5 Bcfes were attributable to our discovery at Vermilion 170 which began producing in fiscal year 2012. At June 30, 2010 the Company had approximately 19.8 Bcfe of PUDs mainly related to Cotton Valley and Travis Peak gas reserves in Panola County, Texas under our joint venture with Patara. These PUDs were sold on May 13, 2011 and the transaction is classified as discontinued operations in our financial statements.

Modernization of Oil and Gas Reporting

Effective June 30, 2010, we implemented the SEC’s final rules related to the modernization of oil and gas reporting (SEC’s reserves rules). Although the SEC’s reserves rules allow probable and possible reserves to be disclosed separately, we have elected not to disclose probable and possible reserves in this report. See Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited) for a description of the most significant revisions to oil and gas reporting disclosures. The SEC's reserve rules does not allow prior-year reserve information to be restated, so all information related to periods prior to June 30, 2010 is presented consistent with prior SEC rules for the estimation of proved reserves.

The line item “Pre-tax net present value, discounted at 10%” in the table above, is not intended to represent the current market value of the estimated natural gas and oil reserves we own. The pre-tax net present value of future cash flows attributable to our proved reserves as of June 30, 2012 was based on $3.13 per million British thermal units (“MMbtu”) for natural gas at the NYMEX, $96.07 per barrel of oil at the West Texas Intermediate Posting, and $59.39 per barrel of NGLs, in each case before adjusting for basis, transportation costs and British thermal unit (“BTU”) content. The pre-tax net present value is a non-GAAP financial measure as defined in Item 10(e) of Regulation S-K. The table below reconciles our calculation of pre-tax net present value to the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Management believes that pre-tax net present value is an important non-GAAP financial measure used by analysts, investors and independent oil and gas producers for evaluating the relative value of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially. The reconciliation of the pre-tax net present value to the standardized measure of discounted future net cash flows relating to our proved oil and natural gas reserves at June 30, 2012 is as follows (in thousands):

	June 30, 2012
Pre-tax net present value, discounted at 10%	$730,222
Future income taxes, discounted at 10%	(216,290)
Standardized measure of discounted future net cash flows	$513,932

While we are reasonably certain of recovering our calculated reserves, the process of estimating natural gas and oil reserves is complex. It requires various assumptions, including natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Our third party engineers must project production rates, estimate timing and amount of development expenditures, analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of all of this data may vary. Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, estimates of proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control.

Item 3. Legal Proceedings

From time to time, we are party to litigation or other legal and administrative proceedings that we consider to be a part of the ordinary course of business. As of the date of this Form 10-K, we are not a party to any material legal proceedings and

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we are not aware of any material proceedings contemplated against us, that could individually or in the aggregate, reasonably be expected to have a material adverse effect on our financial condition, cash flows or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Our common stock was listed on the NYSE MKT (previously the American Stock Exchange) in January 2001 under the symbol "MCF". The table below shows the high and low closing prices of our common stock for the periods indicated.

	High	Low
Fiscal Year 2011:		
Quarter ended September 30, 2010	$51.28	$41.40
Quarter ended December 31, 2010	$59.91	$50.30
Quarter ended March 31, 2011	$63.24	$55.02
Quarter ended June 30, 2011	$64.19	$55.12
Fiscal Year 2012:		
Quarter ended September 30, 2011	$66.29	$53.40
Quarter ended December 31, 2011	$68.74	$52.89
Quarter ended March 31, 2012	$64.66	$57.66
Quarter ended June 30, 2012	$59.92	$51.82

On August 24, 2012, the closing price of our common stock on the NYSE MKT was $57.74 per share, and there were 15,292,448 shares of Contango common stock outstanding.

We have not declared any cash dividends on our shares of common stock. Any future decision to pay dividends on our common stock will be at the discretion of our board and will depend upon our financial condition, results of operations, capital requirements, and other factors our board may deem relevant.

The following table sets forth information about our equity compensation plans at June 30, 2012:

Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (b))
1999 Stock Incentive Plan - approved by security holders	—	$—	—
2009 Equity Compensation Plan - approved by security holders	—	$—	1,475,000
Equity compensation plans not approved by security holders	—	$—	—

The Company's 1999 Stock Incentive Plan (the "1999 Plan") expired in August 2009. The final remaining outstanding options were net-settled with the Company in February 2012 and no options remain outstanding.

On September 15, 2009, the Company's Board of Directors (the "Board") adopted the Contango Oil & Gas Company Equity Compensation Plan (the "2009 Plan"), which was approved by shareholders on November 19, 2009. Under the 2009 Plan, the Board may grant restricted stock and option awards to officers, directors, employees or consultants of the Company. Awards made under the 2009 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Board. As of August 24, 2012, all options issued under the 2009 Plan had been exercised. The Company has not issued any restricted stock under the 2009 Plan.

During the fiscal year ended June 30, 2012, the Company net-settled 45,000 stock options from two employees for a total of approximately $465,000. During the fiscal year ended June 30, 2011, the Company purchased 172,544 shares of its common stock. Of this amount, 152,544 shares were purchased from three officers of the Company, one member of the Board, one employee, and one consultant for a total of approximately $8.9 million. During the fiscal year ended June 30, 2010, the Company purchased 115,454 shares of its common stock from three officers of the Company and two members of the Board

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for a total of approximately $6.4 million. All purchases were approved by the Board under the Company's share repurchase programs described below and were completed at the closing price of the Company's common stock on the date of purchase.

Share Repurchase Programs

$100 Million Share Repurchase Program

In September 2008, the Company's board of directors approved a $100 million share repurchase program which concluded in October 2011. All shares were purchased in the open market or through privately negotiated transactions. The purchases were made subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market. Repurchased shares of common stock became authorized but unissued shares, and may be issued in the future for general corporate and other purposes. During the fiscal year ended June 30, 2012, the Company purchased the below listed shares under its $100 million share repurchase program:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that may yet be Purchased Under Program
August 22 - 23, 2011	36,700	$54.91	1,922,141	$13.0 million
September 21 - 30, 2011	207,000	$55.64	2,129,141	$1.5 million
October 3, 2011	28,137	$54.09	2,157,278	—

$50 Million Share Repurchase Program

On September 28, 2011, the Company's Board of Directors approved the adoption of a $50 million share repurchase program, effective upon completion of purchases under the Company's $100 million share repurchase program. The repurchases will be subject to the same terms and conditions as repurchases made under the $100 million share repurchase program. During the fiscal year ended June 30, 2012, the Company purchased the below listed shares under its $50 million share repurchase program:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that may yet be Purchased Under Program
October 3 - 7, 2011	33,163	$54.38	33,163	$48.2 million
December 14, 2011	2,500	$57.21	35,663	$48.1 million
May 9 - 31, 2012	36,098	$53.56	71,761	$46.1 million
June 1 - 4, 2012	28,620	$51.92	100,381	$44.6 million

In addition to the above, in February 2012 the Company net-settled 45,000 stock options from two employees for a total of approximately $465,000. In total, under both share repurchase programs combined as of August 24, 2012, the Company had invested approximately $105.8 million to purchase 2,257,659 shares of its common stock at an average cost per share of $46.67, and 45,000 stock options. As of August 24, 2012, the Company had 15,292,448 shares of common stock outstanding and no options. Since inception, the Company has purchased approximately 5.0 million shares of stock and options at an average cost of $23.82 per share.

The following graph compares the yearly percentage change from June 30, 2007 until June 30, 2012 in the cumulative total stockholder return on our common stock to the cumulative total return on the S&P Smallcap 600 Index and a peer group of five independent oil and gas exploration companies selected by us. The companies in our selected peer group are ATP Oil & Gas Corp., Callon Petroleum, Energy XXI (Bermuda) Limited, McMoRan Exploration Company, and W&T Offshore, Inc. Our common stock began trading on the NYSE MKT (previously American Stock Exchange) on January 19, 2001 and before that had traded on the Nasdaq over-the-counter Bulletin Board. The graph assumes that a $100 investment was made in our common stock and each index on June 30, 2007, adjusted for stock splits and dividends. The stock performance for our common stock is not necessarily indicative of future performance.

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	6/30/2007	6/30/2008	6/30/2009	6/30/2010	6/30/2011	6/30/2012
Peer Group Composite	100	137	20	40	75	50
S&P 600	100	84	62	76	103	103
Contango Oil & Gas Co.	100	256	117	123	161	163

Item 6. Selected Financial Data

The selected consolidated financial data (not including proved reserve information) set forth below is for continuing operations and should be read in conjunction with Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and with the consolidated financial statements and notes to those consolidated financial statements included elsewhere in this Form 10-K.

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	Year Ended June 30,				
	2012	2011	2010	2009	2008
Financial Data:	(Dollar amounts in thousands, except per share amounts)				
Revenues:					
Natural gas and oil sales	$179,272	$201,721	$159,010	$190,656	$116,498
Total revenues	$179,272	$201,721	$159,010	$190,656	$116,498
Income from continuing operations	$59,213	$64,459	$50,166	$55,861	$83,221
Discontinued operations, net of income taxes	(824)	574	(480)	—	173,685
Net income	$58,389	$65,033	$49,686	$55,861	$256,906
Preferred stock dividends	—	—	—	—	1,548
Net income attributable to common stock	$58,389	$65,033	$49,686	$55,861	$255,358
Net income (loss) per share:					
Basic					
Continuing operations	$3.84	$4.11	$3.17	$3.41	$5.05
Discontinued operations	(0.05)	0.04	(0.03)	—	10.73
Total	$3.79	$4.15	$3.14	$3.41	$15.78
Diluted					
Continuing operations	$3.84	$4.10	$3.11	$3.35	$4.82
Discontinued operations	(0.05)	0.04	(0.03)	—	10.06
Total	$3.79	$4.14	$3.08	$3.35	$14.88
Weighted average shares outstanding:					
Basic	15,423	15,665	15,831	16,363	16,185
Diluted	15,425	15,713	16,157	16,690	17,263
Working capital	$140,901	$126,654	$41,385	$43,232	$29,913
Capital expenditures	$20,844	$69,993	$97,703	$45,742	$119,929
Long term debt	$—	$—	$—	$—	$15,000
Stockholders' equity	$464,339	$426,623	$377,330	$349,364	$341,998
Total assets	$624,654	$636,930	$592,266	$517,042	$599,974
Proved Reserve Data:					
Total proved reserves (Mmcfe)	256,567	296,729	314,027	355,046	369,076
Pre-tax net present value (discounted at 10%)	$730,222	$981,041	$970,442	$889,865	$3,183,843
Standardized Measure	$513,932	$717,135	$712,094	$638,091	$2,233,918

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the financial statements and the related notes and other information included elsewhere in this report.

Overview

Contango is a Houston-based, independent natural gas and oil company. The Company's business is to explore, develop, produce and acquire natural gas and oil properties onshore and offshore in the Gulf of Mexico in water-depths of less than 300 feet. COI, our wholly-owned subsidiary, acts as operator on certain offshore properties.

Revenues and Profitability. Our revenues, profitability and future growth depend substantially on prevailing prices for

natural gas and oil and on our ability to find, develop and acquire natural gas and oil reserves that are economically recoverable.

Reserve Replacement. Generally, our producing properties offshore in the Gulf of Mexico have high initial production rates, followed by steep declines. As a result, we must locate and develop or acquire new natural gas and oil reserves to replace those being depleted by production. Substantial capital expenditures are required to find, develop and acquire natural gas and oil reserves.

Sale of proved properties. From time-to-time as part of our business strategy, we have sold, and in the future may continue to sell some or a substantial portion of our proved reserves to capture current value, using the sales proceeds to reduce debt and further our exploration activities.

Use of Estimates. The preparation of our financial statements requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include estimates of remaining proved natural gas and oil reserves, the timing and costs of our future drilling, development and abandonment activities, and income taxes.

Related Party Transactions. The Company relies on JEX and REX to generate its offshore and onshore domestic natural gas and oil prospects. In addition to generating new prospects, JEX occasionally evaluates offshore and onshore exploration prospects generated by third-party independent companies for us to purchase. See Note 13 - Related Party Transactions for a detailed description of our transactions with JEX and REX.

See “Risk Factors” on page 13 for a more detailed discussion of a number of other factors that affect our business, financial condition and results of operations.

Impact of Deepwater Horizon Incident and Federal Deepwater Moratorium

In April 2010, the deepwater Gulf of Mexico drilling rig Deepwater Horizon, engaged in drilling operations for another operator, sank after an apparent blowout and fire. In response, the Secretary of the Interior required all drilling operations in the Gulf of Mexico to stop until operators certify that they have adequate plans in place to quickly shut down an out-of-control well, that the blowout preventers atop the wells it drills have passed rigorous new tests, and that sufficient cleanup resources are on hand in the event of a spill.

Business Impact

We believe that the Deepwater Horizon incident will have a significant and lasting effect on the U.S. offshore energy industry, and will result in a number of fundamental changes, including heightened regulatory scrutiny, more stringent operating and safety standards, changes in equipment requirements and the availability and cost of insurance, as well as increased politicization of the industry. A significant delay of planned exploratory activities will reduce our longer term ability to replace reserves, resulting in a negative impact on production, including a reduction in operating results and cash flows as we deplete our reserves. There may be other impacts of which we are not aware at this time.

Finally, the potential for removal of the liability cap for claims of damages from oil spills, and/or the enactment of onerous rules and regulations regarding activities in the Gulf of Mexico could significantly alter our industry. Such rules could effectively limit which companies can operate in the Gulf of Mexico. Small and medium-sized oil and gas companies may not be able to obtain insurance coverage at economically appropriate levels or meet financial responsibility requirements and would be forced to exit operations in the Gulf of Mexico. Potentially less attractive economics for exploration and development programs going forward will require companies retaining operations in the Gulf of Mexico to review their business models. We have drilled, and believe we can continue to drill, safely in the Gulf of Mexico. However, exploration and production companies will be able to continue doing business in the Gulf of Mexico only to the extent it remains economically viable.

Delays and volatility are inherent in our business. We have maintained a capital structure with a strong liquidity position allowing us to manage during periods of uncertainty. We believe we are well-positioned to respond to the increasingly complex regulatory framework for the Gulf of Mexico.

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Results of Operations

The following table shows the relationship between volumes and revenues from continuing operations.

	Fiscal Year Ended June 30,					
	2012			2011		
	(thousands, except percentage)					
Natural gas volumes (Mcf)	23,617	75.50	%	24,268	75.48	%
Condensate and NGL volumes (Mcfe)	7,662	24.50	%	7,885	24.52	%
Total volumes	31,279			32,153		
Natural gas revenues	$73,232	40.85	%	$106,781	52.93	%
Condensate and NGL revenues	106,040	59.15	%	94,940	47.07	%
Total revenues	$179,272			$201,721		

The table below sets forth average daily production data in Mmcfed from our offshore wells for the three months ended for each of the periods presented:

Production	September 30, 2011	December 31, 2011	March 31, 2012	June 30, 2012
Dutch and Mary Rose wells	63.2	66.2	59.3	67.5
Ship Shoal 263 well (Nautilus)	7.6	10.9	7.8	7.6
Vermilion 170 well (Swimmy)	2.3	17.2	15.3	15.5
Non-operated wells	0.3	0.2	0.3	0.2
	73.4	94.5	82.7	90.8

Dutch and Mary Rose Wells. Third-party platform and pipeline repairs, as well as third-party gas processing plant shut-ins reduced our flowrates at our Dutch #1, #2, and #3 wells during the three months ended September 2011. During the three
months ended March 31, 2012 our Dutch #1, #2 and #3 wells were shut in for a total of 10 days for maintenance and to repair a small pipeline leak. As of August 24, 2012, these ten wells were flowing approximately 67.1 Mmcfed, net to Contango.

Ship Shoal 263 Well (Nautilus). For the three months ended September 30, 2011, production at Ship Shoal 263 was temporarily shut-in due to a leak on a third-party owned and operated pipeline. For the three months ended March 31, 2012 and June 30, 2012, production was intermittent due to overheating and scaling problems. As of August 24, 2012, the well was flowing at approximately 3.0 Mmcfed, net to Contango.

Vermilion 170 Well (Swimmy). Our Vermilion 170 well began production in September 2011, and as of August 24, 2012, was flowing at approximately 13.4 Mmcfed, net to Contango.

The table below sets forth revenue, production data, average sales prices and average production costs associated with our sales of natural gas, oil and natural gas liquids ("NGLs") from continuing operations for the fiscal years ended June 30, 2012, 2011 and 2010. Oil, condensate and NGLs are compared with natural gas in terms of cubic feet of natural gas equivalents. One barrel of oil, condensate or NGL is the energy equivalent of six thousand cubic feet (“Mcf”) of natural gas. Reported lease operating expenses include property and severance taxes.

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	Year ended June 30,			Year ended June 30,		
	2012	2011	%	2011	2010	%
Revenues:	(thousands)			(thousands)		
Natural gas and oil sales	$179,272	$201,721	(11)%	$201,721	$159,010	27%
Total revenues	$179,272	$201,721		$201,721	$159,010	
Production:						
Natural gas (million cubic feet)	23,617	24,268	(3)%	24,268	21,081	15%
Oil and condensate (thousand barrels)	615	673	(9)%	673	504	34%
Natural gas liquids (thousand gallons)	27,801	26,926	3%	26,926	24,690	9%
Total (million cubic feet equivalent)	31,279	32,153	(3)%	32,153	27,632	16%
Natural gas (million cubic feet per day)	64.5	66.5	(3)%	66.5	57.8	15%
Oil and condensate (thousand barrels per day)	1.7	1.8	(9)%	1.8	1.4	34%
Natural gas liquids (thousand gallons per day)	76.0	73.8	3%	73.8	67.6	9%
Total (million cubic feet equivalent per day)	85.5	88.1	(3)%	88.1	75.7	16%
Average Sales Price:						
Natural gas (per thousand cubic feet)	$3.10	$4.40	(30)%	$4.40	$4.48	(2)%
Oil and condensate (per barrel)	$112.75	$91.98	23%	$91.98	$77.18	19%
Natural gas liquids (per gallon)	$1.32	$1.23	7%	$1.23	$1.04	18%
Total (per thousand cubic feet equivalent)	$5.73	$6.27	(9)%	$6.27	$5.75	9%
Operating expenses	$25,183	$25,691	(2)%	$25,691	$16,692	54%
Exploration expenses	$346	$9,751	(96)%	$9,751	$20,850	(53)%
Depreciation, depletion and amortization	$49,052	$52,198	(6)%	$52,198	$34,521	51%
Impairment of natural gas and oil properties	$—	$1,786	(100)%	$1,786	$952	88%
General and administrative expenses	$10,418	$12,341	(16)%	$12,341	$4,599	168%
Other income (expense)	$(312)	$(157)	99%	$(157)	$511	(131)%
Loss from affiliates (net of tax of $241)	$(449)	$—	100%	$—	$—	—%
Selected data per Mcfe:						
Operating expenses	$0.81	$0.80	1%	$0.80	$0.60	33%
General and administrative expenses	$0.33	$0.38	(13)%	$0.38	$0.17	124%
Depreciation, depletion and amortization of natural gas and oil properties	$1.54	$1.61	(4)%	$1.61	$1.24	30%

Not included in the table above is production information from our discontinued operations. For the fiscal year ended June 30, 2012, our discontinued operations produced approximately 1.7 Mmcf of natural gas at an average price of $3.79 per Mcf. For the fiscal year ended June 30, 2011, our discontinued operations produced approximately 1,892

Mmcf of natural gas, 12.8 MBbls of condensate, and 2.6 million gallons of natural gas liquids at an average price of $3.45 per Mcf, $86.91 per Bbl and $0.96 per gallon, respectively. For the fiscal year ended June 30, 2010, our discontinued operations produced approximately 305 Mmcf of natural gas, 1.2 MBbls of condensate, and 428 thousand gallons of natural gas liquids at an average price of $3.72 per Mcf, $75.90 per Bbl and $1.04 per gallon, respectively.

Natural Gas, Oil and NGL Sales. All of our revenues are from the sale of our natural gas, oil and natural gas liquids production. Our revenues may vary significantly from year to year depending on changes in commodity prices, which fluctuate widely, and production volumes. Our production volumes are subject to wide swings as a result of new discoveries, weather and mechanical related problems. In addition, our production declines over time as we produce our reserves.

We reported revenues of approximately $179.3 million for the year ended June 30, 2012, compared to revenues of approximately $201.7 million for the year ended June 30, 2011. This decrease in sales was principally attributable to lower equivalent production for the period (discussed below) as well as a lower average equivalent sales price received for the period.

We reported revenues of approximately $201.7 million for the year ended June 30, 2011, up from approximately $159.0 million reported for the year ended June 30, 2010. This increase in sales was primarily attributable to increased natural gas, oil and NGL production for the period (discussed below) as well as higher oil and NGL prices for the period, slightly offset by lower natural gas prices.

Average Sales Prices. For the year ended June 30, 2012, the price of natural gas was $3.10 per Mcf while the price for oil and NGLs was $112.75 per barrel and $1.32 per gallon, respectively. For the year ended June 30, 2011, the price of natural gas was $4.40 per Mcf while the price for oil and NGLs was $91.98 per barrel and $1.23 per gallon, respectively. For the year ended June 30, 2010, the price of natural gas was $4.48 per Mcf while the price for oil and NGLs was $77.18 per barrel and $1.04 per gallon, respectively.

Natural Gas, Oil and NGL Production. Our net natural gas production for the year ended June 30, 2012 was approximately 64.5 Mmcfd, down from approximately 66.5 Mmcfd for the year ended June 30, 2011. Net oil and condensate production for the comparable periods also decreased from approximately 1,800 barrels per day to approximately 1,700 barrels per day, and our NGL production increased from approximately 73,800 gallons per day to approximately 76,000 gallons per day. In total, equivalent production decreased from 88.1 Mmcfed to 85.5 Mmcfed, principally attributable to our Eloise North well which stopped producing in October 2011 and was subsequently recompleted as our Mary Rose #5 well in January 2012. Since recompletion, this well has only produced intermittently. Partially offsetting this decrease in production is our Vermilion 170 well which began producing in fiscal year 2012.

Our net natural gas production for the year ended June 30, 2011 was approximately 66.5 Mmcfd, up from approximately 57.8 Mmcfd for the year ended June 30, 2010. Net oil production and NGL production also increased for the comparable periods. Net oil production increased from 1,400 barrels per day to 1,800 barrels per day, while NGL production increased from approximately 67,600 gallons per day to 73,800 gallons per day. In total, equivalent production increased from 75.7 Mmcfed to 88.1 Mmcfed. This increase in natural gas, oil and NGL production was principally attributable to our Ship Shoal 263 well which began producing in June 2010 and our Eloise South well (now our Dutch #5 well) which began producing in July 2010. Also contributing to the increase in production was increased production from our four Mary Rose wells, Dutch #4 and our Eloise North well (now our Mary Rose #5 well), which had been shut-in for approximately 35 days during fiscal year 2010 due to our ruptured 20” pipeline. This increase in production was partially offset by temporarily shutting in our Eloise South well in October 2010 and our Eloise North well in February 2011 for remedial work.

Operating Expenses. Operating expenses for the year ended June 30, 2012 were approximately $25.2 million, which included approximately $4.1 million in Louisiana state severance taxes, $1.6 million in workover costs, and $4.4 million of well insurance. The remaining $15.1 million related to lease operating expenses for 12 offshore wells.

Operating expenses for the year ended June 30, 2011 were approximately $25.7 million, which included approximately $4.6 million in Louisiana state severance taxes, $1.7 million in workover costs, and $4.6 million of well insurance. The remaining $14.8 million related to lease operating expenses for 11 offshore wells. Operating expenses for the year ended June 30, 2010 were approximately $16.7 million, which included approximately $5.3 million of Louisiana state severance taxes, $0.7 million in workover costs and $10.7 million related to lease operating expenses for nine offshore wells.

Exploration Expenses. We reported approximately $0.3 million of exploration expenses for the year ended June 30, 2012, related to various geological and geophysical activities, seismic data and delay rentals.

We reported approximately $9.8 million of exploration expenses for the year ended June 30, 2011. Of this amount, approximately $9.5 million related to our dry hole at Galveston Area 277L, and the remaining $0.3 million related to various geological and geophysical activities, seismic data, and delay rentals.

We reported approximately $20.9 million of exploration expenses for the year ended June 30, 2010. Of this amount, approximately $14.9 million related to the dry hole the Company drilled at Matagorda Island 617, $5.3 million related to the dry hole the Company drilled at Vermillion 155, and the remaining $0.7 million related to various geological and geophysical activities, seismic data and delay rentals.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization for the year ended June 30, 2012 was approximately $49.1 million. This compares to approximately $52.2 million for the year ended June 30, 2011. The decrease in depreciation, depletion and amortization was primarily attributable to an overall decrease in production due to our Eloise North well which stopped producing in October 2011 and was subsequently recompleted as our Mary Rose #5 well in January 2012. Since recompletion, this well has only produced intermittently. Partially offsetting this decreased production is our Vermilion 170 well which began producing in fiscal year 2012.

Depreciation, depletion and amortization for the year ended June 30, 2011 was approximately $52.2 million. This compares to approximately $34.5 million for the year ended June 30, 2010. The increase in depreciation, depletion and amortization was primarily attributable to an overall increase in production and increase in capitalized costs as a result of our Ship Shoal 263 and Eloise South discoveries. Also contributing to the increase in depreciation, depletion and amortization were increased produced volumes from our four Mary Rose wells, Dutch #4 and our Eloise North wells, which had been shut-in for approximately 35 days in 2010 due to our ruptured 20” pipeline. This increase in depreciation, depletion and amortization was partially offset by temporarily shutting in our Eloise South well in October 2010 and our Eloise North well in February 2011 for remedial work.

Impairment of Natural Gas and Oil Properties. No impairment expense was recorded for the year ended June 30, 2012. For the year ended June 30, 2011, the Company recorded impairment expense of approximately $1.8 million related to the relinquishment of 14 lease blocks owned by Contango and REX. For the year ended June 30, 2010, the Company recorded impairment expense of approximately $1.0 million, related to the relinquishment of six lease blocks owned by REX and COE.

General and Administrative Expenses. General and administrative expenses for the year ended June 30, 2012 were approximately $10.4 million, compared to approximately $12.3 million for the year ended June 30, 2011. Major components of general and administrative expenses for the year ended June 30, 2012 included approximately $6.6 million in salaries, bonuses, stock-based compensation, benefits and board compensation, $0.4 million in insurance costs, $0.7 million in accounting and tax services, $0.9 million in legal and consulting expenses, $0.7 million in franchise taxes, and $1.1 million in office administration and other expenses.

General and administrative expenses for the year ended June 30, 2011 were approximately $12.3 million, up from approximately $4.6 million for the year ended June 30, 2010. The increase is principally attributable to higher bonus payments and stock option expenses in the year ended June 30, 2011. Major components of general and administrative expenses for the year ended June 30, 2011 included approximately $9.6 million in salaries, bonuses, stock-based compensation, benefits and board compensation (includes $1.3 million in non-cash expenses related to option awards), $0.9 million in office administration and other expenses, $0.5 million in insurance costs, $0.5 million in accounting and tax services, and $0.8 million in legal, consulting and other administrative expenses.

General and administrative expenses for the year ended June 30, 2010 were approximately $4.6 million. Major components of general and administrative expenses for the year ended June 30, 2010 included approximately $3.0 million in salaries, stock-based compensation, benefits and board compensation (includes $0.7 million in non-cash expenses related to restricted stock and option awards), $0.5 million in office administration and other expenses, $0.5 million in insurance costs, $0.2 million in accounting and tax services, and $0.4 million in legal, consulting and other administrative expenses.

Discontinued Operations. The table and discussions above, along with our financial statements, discuss only continuing operations for all fiscal years presented. Not reflected are the Company’s sold producing properties which generated approximately 0%, 5% and 1% of combined revenues for the fiscal year ended June 30, 2012, 2011 and 2010, respectively. See Note 5 – Discontinued Operations of Notes to Consolidated Financial Statements included as part of this Form 10-K, for a discussion of our discontinued operations.

Capital Resources and Liquidity

Cash From Operating Activities. Cash flow from operating activities provided approximately $73.6 million in cash for the year ended June 30, 2012 compared to $140.6 million for the same period in 2011. This decrease in cash provided by operating activities was primarily attributable to decreased natural gas, oil and NGL sales and production as well as higher amounts of taxes paid due to reduced drilling activities in 2012.

Cash flow from operating activities provided approximately $140.6 million in cash for the year ended June 30, 2011 compared to $128.2 million for the same period in 2010. This increase in cash provided by operating activities was primarily attributable to increased sales due to increased natural gas, oil and NGL production attributable to our Ship Shoal 263 and Eloise South wells, as well as from other wells which were shut-in for approximately 35 days in fiscal year 2010.

Cash From Investing Activities. Cash used in investing activities for the year ended June 30, 2012 was approximately $73.4 million, compared to $33.3 million used in investing activities for the year ended June 30, 2011. The higher level of cash used in investing activities in 2012 was primarily attributable to investing approximately $53.4 million in affiliates, partially offset by a decrease in capital expenditures for drilling exploration and development wells.

Cash used in investing activities for the year ended June 30, 2011 was approximately $33.3 million, compared to $97.7 million used in investing activities for the year ended June 30, 2010. The lower level of cash used in investing activities in 2011 was primarily attributable to decreased capital expenditures for drilling exploration and development wells as well as $38.7 million received from the sale of oil and gas properties.

Cash From Financing Activities. Cash used in financing activities for the year ended June 30, 2012 were approximately $20.2 million, compared to $9.8 million used in financing activities for the same period in 2011. During the fiscal year ended June 30, 2012, the Company invested significantly more to repurchase shares of its common stock pursuant to its share repurchase program.

Cash used in financing activities for the year ended June 30, 2011 were approximately $9.8 million, compared to $22.4 million used in financing activities for the same period in 2010. During the fiscal year ended June 30, 2011, the Company did not repurchase as many shares of its common stock pursuant to its share repurchase program, as it did in for the fiscal year ended June 30, 2010.

Income Taxes. During the year ended June 30, 2012, 2011 and 2010, we paid approximately $50.7 million, $31.9 million, and $11.5 million, respectively, in federal and state income taxes, net of refunds received.

Capital Budget. For the remainder of fiscal year 2013, our capital expenditure budget calls for us to invest approximately $146.7 million from cash flow from operations and cash on hand as follows:

- We have budgeted to invest approximately $25.0 million to drill our Ship Shoal 134 (“Eagle”) prospect.
- We have budgeted to invest approximately $28.0 million to drill our South Timbalier 75 (“Fang”) prospect.
- We have budgeted to invest approximately $7.2 million to complete laying flowlines and installing compression at our Eugene Island 11 and Vermilion 170 platforms.
- We have budgeted to invest approximately $7.6 million for remaining leasehold costs and rental payments for the six blocks we bid on at the Central Gulf of Mexico Lease Sale 216/222.
- We have budgeted to invest approximately $30 million to drill two wildcat exploration wells in the Gulf of Mexico.
- We have budgeted to invest approximately $41.2 million in Exaro Energy III LLC (remaining balance of $82.5 million commitment).
- We have budgeted to invest approximately $7.7 million in Alta Energy (remaining balance of $20 million commitment).

Should we be successful in any of our offshore prospects, we will have the opportunity to spend significantly more capital to complete development and bring the discovery to producing status. The Company often reviews acquisitions and prospects presented to us by third parties and may decide to invest in one or more of these opportunities. There can be no assurance that we will invest, or that any investment entered into will be successful. These potential investments are not part of our current capital budget and would require us to invest additional capital. Natural gas and oil prices continue to be volatile and our resources may be insufficient to fund any of these opportunities. As of August 24, 2012, we had approximately $124.7 million in cash and cash equivalents and no debt outstanding.

Discontinued Operations. The Company, since its inception in September 1999, has raised approximately $524 million in proceeds from property sales, and views periodic reserve sales as an opportunity to capture value, reduce reserve and price risk, in addition to being a source of funds for potentially higher rate of return natural gas and oil exploration investments. We believe these periodic natural gas and oil property sales are an efficient strategy to meet our cash and liquidity needs by providing us with immediate cash, which would otherwise take years to realize through the production lives of the fields sold. We have in the past and expect to in the future to continue to rely on the sales of assets to generate cash to fund our exploration investments and operations.

These sales bring forward future revenues and cash flows, but our longer term liquidity could be impaired to the extent our exploration efforts are not successful in generating new discoveries, production, revenues and cash flows.

Additionally, our longer term liquidity could be impaired due to the decrease in our inventory of producing properties that could be sold in future periods. Further, as a result of these property sales the Company's ability to collateralize bank borrowings is reduced which increases our dependence on more expensive mezzanine debt and potential equity sales. The availability of such funds will depend upon prevailing market conditions and other factors over which we have no control, as well as our financial condition and results of operations.

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The table below sets forth the proceeds received from natural gas and oil property sales for the year ended June 30, 2011, the impact of these sales on our developed reserve quantities, and a measure of our developed reserves held at the end of each such fiscal year. See the reserve activity reported in the Supplemental Oil and Gas Disclosures on pages F-23 through F-26 for a more detailed discussion regarding our standardized measure.

Fiscal Year of Property Sale	Proceeds Received	Reserves Sold (Bcfe)	Reserves at end of Fiscal Year (Bcfe)	Standardized Measure of Discounted Future Net Cash Flows at end of Fiscal Year ('000)
2011	38.7 million	17.2	296.7	$717,360

For fiscal year 2012, 2011 and 2010, the Company realized approximately $(0.4) million, $6.7 million and $0.4 million in operating cash flows from discontinued operations, approximately $10,000, $10.9 million and $(25.2) million in investing cash flows from discontinued operations and approximately $0.4 million, $(17.5) million and $24.8 million in financing cash flows from discontinued operations.

Off Balance Sheet Arrangements

None.

Contractual Obligations

The following table summarizes our known contractual obligations as of June 30, 2012:

	Payment due by period (thousands)				
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Long term debt	$—	$—	$—	$—	$—
Delay rentals	383	122	221	40	—
Asset retirement obligations	21,400	—	—	—	21,400
Operating leases	876	248	502	126	—
Total	$22,659	$370	$723	$166	$21,400

In addition, the Company pays a commitment fee of 0.125% on the unused borrowing capacity of our $40 million credit facility with Amegy Bank (See "Credit Facility" below). We have also committed to invest up to an additional $41.2 million in Exaro Energy, an additional $8.4 million ($7.7 million as of August 24) in Alta Energy, and an additional $8.8 million ($7.6 million as of August 24) for remaining leasehold costs and rental payments for the six blocks we bid on at the Central Gulf of Mexico Lease Sale 216/222.

Credit Facility

On October 22, 2010, the Company completed the arrangement of a secured revolving credit agreement with Amegy Bank (the "Credit Agreement"). The Credit Agreement currently has a $40 million hydrocarbon borrowing base available to fund the Company's exploration and development activities, as well as repurchase shares of common stock of the Company and to fund working capital as needed. The Credit Agreement is secured by substantially all of the assets of the Company, including our natural gas and oil properties. Borrowings under the Credit Agreement bear interest at LIBOR plus 2.5%, subject to a LIBOR floor of 0.75%. The principal is due October 1, 2014, and may be prepaid at any time with no prepayment penalty. An arrangement fee of $300,000 was paid in connection with the facility and effective November 1, 2011, a commitment fee of 0.125% is owed on unused borrowing capacity. The Credit Agreement contains customary covenants including limitations on our current ratio and additional indebtedness. As of the date of this report, the Company was in compliance with all covenants and had no amounts outstanding under the Credit Agreement.

Application of Critical Accounting Policies and Management's Estimates

The discussion and analysis of the Company's financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these consolidated financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. The Company's significant accounting policies are described in Note 2 of Notes to Consolidated Financial Statements included as part of this Form 10-K. We have identified below the policies that are of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. The Company analyzes its estimates, including those related to natural gas and oil reserve estimates, on a periodic basis and bases its estimates on historical experience, independent third party reservoir engineers and various other assumptions that management believes to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. The Company believes the following critical accounting policies affect its more significant judgments and estimates used in the preparation of the Company's consolidated financial statements:

Successful Efforts Method of Accounting. Our application of the successful efforts method of accounting for our natural gas and oil exploration and production activities requires judgments as to whether particular wells are developmental or exploratory, since exploratory costs and the costs related to exploratory wells that are determined to not have proved reserves must be expensed whereas developmental costs are capitalized. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver natural gas and oil in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. On occasion, wells are drilled which have targeted geologic structures that are both developmental and exploratory in nature, and in such instances an allocation of costs is required to properly account for the results. Delineation seismic costs incurred to select development locations within a productive natural gas and oil field are typically treated as development costs and capitalized, but often these seismic programs extend beyond the proved reserve areas and therefore management must estimate the portion of seismic costs to expense as exploratory.

Reserve Estimates. While we are reasonably certain of recovering our reported reserves, the Company's estimates of natural gas and oil reserves are, by necessity, projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable natural gas and oil reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing future natural gas and oil prices, future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. The future development costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves are later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of expected natural gas and oil attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company's natural gas and oil properties and/or the rate of depletion of such natural gas and oil properties. In June 2010, the Company revised its offshore reserves downward by approximately 48.5 Bcfe. This revision was attributable to newly obtained bottom hole pressure data as a result of a recent field wide shut-in and a "P/Z pressure test" that indicated fewer reserves than was originally estimated.

Actual production, revenues and expenditures with respect to the Company's reserves will likely vary from estimates, and such variances may be material. Holding all other factors constant, a reduction in the Company's proved reserve estimate at June 30, 2012 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately \$2.5 million, \$5.3 million, and \$8.5 million, respectively.

Impairment of Natural Gas and Oil Properties. The Company reviews its proved natural gas and oil properties for impairment whenever events and circumstances indicate a potential decline in the recoverability of their carrying value. The Company compares expected undiscounted future net cash flows from each field to the unamortized capitalized cost of the asset. If the future undiscounted net cash flows, based on the Company's estimate of future natural gas and oil prices and operating costs and anticipated production from proved reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to fair market value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity pricing, future production estimates, and anticipated capital expenditures. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. Drilling activities in an area by other companies may also effectively condemn leasehold positions. Given the complexities associated with natural gas and oil reserve estimates and the history of price volatility in the natural gas and oil markets, events may arise that will require the Company to record an impairment of its natural gas and oil properties and there can be no assurance that such impairments will not be required in the future nor that they will not be material.

Income Taxes. Income taxes are provided for the tax effects of transactions reported in the financial statements and consists of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are measured by applying currently enacted tax rates to the differences between financial statements and income tax reporting. Numerous judgments and assumptions are inherent in the determination of deferred income tax assets and liabilities as well as income taxes payable in the current period. We are subject to taxation in several jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions.

Recent Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2011-11 Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities (ASU 2011-11). ASU 2011-11 requires that an entity disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU 2011-11 is effective for annual and interim periods beginning on or after January 1, 2013. We are currently evaluating the provisions of ASU 2011-11 and assessing the impact, if any, it may have on the disclosures in our financial statements.

Item 7A. Quantitative and Qualitative Disclosure about Market Risk

Commodity Risk. Our major commodity price risk exposure is to the prices received for our natural gas and oil production. Realized commodity prices received for our production are tied to the spot prices applicable to natural gas and crude oil at the applicable delivery points. Prices received for natural gas and oil are volatile and unpredictable. We do not hedge against price risk exposure. For the year ended June 30, 2012, a 10% fluctuation in the prices received for natural gas and oil production would have had an approximately $17.9 million impact on our revenues.

Interest Rate Risk. As of August 24, 2012, we have no long-term debt subject to the risk of loss associated with movements in interest rates.

As of June 30, 2012, we had approximately $130.0 million in cash and cash equivalents, all of which was held in non-interest bearing accounts. Investments in fixed-rate, interest-earning instruments carry a degree of interest rate and credit rating risk. Fixed-rate securities may have their fair market value adversely impacted because of changes in interest rates and credit ratings. Additionally, the value of our investments may be impaired temporarily or permanently. Due in part to these factors, our investment income may decline and we may suffer losses in principal. Currently, we do not use any derivative or other financial instruments or derivative commodity instruments to hedge any market risks, including changes in interest rates or credit ratings, and we do not plan to employ these instruments in the future. Because of the nature of the issuers of the securities that we invest in, we do not believe that we have any cash flow exposure arising from changes in credit ratings. Based on a sensitivity analysis performed on the financial instruments held as of June 30, 2012, an immediate 10% change in interest rates is not expected to have a material effect on our near-term financial condition or results of operations.

Item 8. Financial Statements and Supplementary Data

The financial statements and supplemental information required to be filed under Item 8 of Form 10-K are presented on pages F-1 through F-27 of this Form 10-K.

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

An evaluation was performed under the supervision and with the participation of the Company's senior management of the effectiveness of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act")) as of June 30, 2012, the end of the period covered by this report. Based on that evaluation, the Company's management, including the Chairman, Acting Chief Executive Officer, Chief Financial Officer, and Chief Accounting Officer, concluded that the Company's disclosure controls and procedures were effective as of such date to ensure that information required to be disclosed in the reports that the Company files under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (ii) accumulated and communicated to the Company's management, including the Chairman, Acting Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control Over Financial Reporting

There was no change in our internal controls over financial reporting during the three months ended June 30, 2012 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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Management’s Report on Internal Control Over Financial Reporting

The Company’s management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of the Company’s management, including the Chairman, Acting Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Company’s evaluation under the framework in Internal Control—Integrated Framework, the Company’s management concluded that its internal control over financial reporting was effective as of June 30, 2012.

Grant Thornton LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Annual Report on Form 10-K, has audited the effectiveness of our internal control over financial reporting as of June 30, 2012, as stated in their report which is included herein.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Contango Oil & Gas Company

We have audited Contango Oil & Gas Company's (a Delaware corporation) internal control over financial reporting as of June 30, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). Contango Oil & Gas Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management’s report on internal control over financial reporting. Our responsibility is to express an opinion on Contango Oil & Gas Company’s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Contango Oil & Gas Company maintained, in all material respects, effective internal control over financial reporting as of June 30, 2012, based on criteria established in Internal Control—Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Contango Oil & Gas Company as of June 30, 2012 and 2011, and the related consolidated statements of operations, shareholders’ equity, and cash flows for each of the three years in the period ended June 30, 2012 and our report dated August 29, 2012 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP
Houston, Texas
August 29, 2012

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Item 9B. Other Information

On September 30, 2008, the Company adopted a Stockholder Rights Plan (the "Plan") which expired in September 30, 2011. The Plan was designed to ensure that all stockholders of Contango receive fair value for their shares of common stock in the event of any proposed takeover of Contango and to guard against the use of partial tender offers or other coercive tactics to gain control of Contango without offering fair value to all of Contango's stockholders. The Plan was not intended, nor did it operate, to prevent an acquisition of Contango on terms that are favorable and fair to all stockholders. Upon expiration of the Plan, the Company did not adopt, and does not currently intend to adopt, a similar plan.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information regarding directors, executive officers, promoters and control persons required under Item 10 of Form 10-K will be contained in our Definitive Proxy Statement for our 2012 Annual Meeting of Stockholders (the “Proxy Statement”) under the headings “Election of Directors”, “Executive Compensation”, “Section 16(a) Beneficial Ownership Reporting Compliance” and “Corporate Governance” and is incorporated herein by reference. The Proxy Statement will be filed with the SEC pursuant to Regulation 14A of the Exchange Act, not later than 120 days after June 30, 2012.

Item 11. Executive Compensation

The information required under Item 11 of Form 10-K will be contained in the Proxy Statement under the heading “Executive Compensation” and is incorporated herein by reference.

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

The information required under Item 12 of Form 10-K will be contained in the Proxy Statement under the heading “Security Ownership of Certain Other Beneficial Owners and Management” and is incorporated herein by reference.

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

The information required under Item 13 of Form 10-K will be contained in the Proxy Statement under the heading “Certain Relationships and Related Transactions, and Director Independence” and “Executive Compensation” and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required under Item 14 of Form 10-K will be contained in the Proxy Statement under the heading “Principal Accountant Fees and Services” and is incorporated herein by reference.

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PART IV
Item 15. Exhibits and Financial Statement Schedules
(a) Financial Statements and Schedules:
The financial statements are set forth in pages F-1 to F-21 of this Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.
(b) Exhibits:
The following is a list of exhibits filed as part of this Form 10-K. Where so indicated by a footnote, exhibits, which were previously filed, are incorporated herein by reference.

Exhibit Number	Description
2.1	Purchase and Sale Agreement, by and between Juneau Exploration, L.P. and REX Offshore Corporation, dated as of September 1, 2005. (10)
2.2	Purchase and Sale Agreement, by and between Juneau Exploration, L.P. and COE Offshore, LLC dated as of September 1, 2005. (10)
3.1	Certificate of Incorporation of Contango Oil & Gas Company. (5)
3.2	Bylaws of Contango Oil & Gas Company. (5)
3.3	Agreement of Plan of Merger of Contango Oil & Gas Company, a Delaware corporation, and Contango Oil & Gas Company, a Nevada corporation. (5)
3.4	Amendment to the Certificate of Incorporation of Contango Oil & Gas Company. (8)
4.1	Facsimile of common stock certificate of Contango Oil & Gas Company. (1)
4.4	Certificate of Designation of Series F Junior Preferred Stock of Contango Oil & Gas Company dated September 30, 2008. (16)
4.5	Rights Agreement, dated as of September 30, 2008, between Contango Oil & Gas Company and Computershare Trust Company, N.A., as Rights Agent. (16)
10.1	Agreement, dated effective as of September 1, 1999, between Contango Oil & Gas Company and Juneau Exploration, L.L.C. (2)
10.2	Securities Purchase Agreement dated August 24, 2000 by and between Contango Oil & Gas Company and Trust Company of the West. (3)
10.3	Securities Purchase Agreement dated August 24, 2000 by and between Contango Oil & Gas Company and Fairfield Industries Incorporated. (3)
10.4	Securities Purchase Agreement dated August 24, 2000 by and between Contango Oil & Gas Company and Juneau Exploration Company, L.L.C. (3)
10.5	Amendment dated August 14, 2000 to agreement between Contango Oil & Gas Company and Juneau Exploration Company, LLC. dated effective as of September 1, 1999. (4)
10.6	Asset Purchase Agreement by and among Juneau Exploration, L.P. and Contango Oil & Gas Company dated January 4, 2002. (6)
10.7	Asset Purchase Agreement by and among Mark A. Stephens, John Miller, The Hunter Revocable Trust, Linda G. Ferszt, Scott Archer and the Archer Revocable Trust and Contango Oil & Gas Company dated January 9, 2002. (7)
10.8	Second Amended and Restated Credit Agreement dated as of October 1, 2010 among Contango Oil & Gas Company, Contango Operators, Inc. and Amegy Bank National Association, as Administrative Agent and Letter of Credit Issuer, together with First Amendment to Second Amended and Restated Credit Agreement dated October 20, 2010 among Contango Oil & Gas Company, Contango Operators, Inc. and Amegy Bank National Association. (19)
10.9	Purchase and Sale Agreement between Juneau Exploration, L.P. and Contango Operators, Inc. dated October 1, 2010. (20)

10.10	Purchase and Sale Agreement between Conterra Company as Seller, and Patara Oil & Gas LLC as Purchaser, dated April 22, 2011. (21)
10.11	Limited Liability Company Agreement of Republic Exploration LLC dated August 24, 2000. (10)

10.12		Amendment to Limited Liability Company Agreement and Additional Agreements of Republic Exploration LLC dated as of September 1, 2005. (10)
10.13		Limited Liability Company Agreement of Contango Offshore Exploration LLC dated November 1, 2000. (10)
10.14		First Amendment to Limited Liability Company Agreement and Additional Agreements of Contango Offshore Exploration LLC dated as of September 1, 2005. (10)
10.15	*	Contango Oil & Gas Company 1999 Stock Incentive Plan. (11)
10.16	*	Amendment No. 1 to Contango Oil & Gas Company 1999 Stock Incentive Plan dated as of March 1, 2001. (11)
10.17		Demand Promissory Note dated October 26, 2006 with Schedules I, II and III. (12)
10.18		Assignment of Operating Rights Interest between CGM, LP and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.19		Partial Assignment of Oil and Gas Leases between CGM, LP and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.20		Assignment of Operating Rights Interest between CGM, LP and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.21		Assignment of Operating Rights Interest between Olympic Energy Partners, LLC and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.22		Partial Assignment of Oil and Gas Leases between Olympic Energy Partners, LLC and Contango Operators, Inc. dated as of January 3, 2008. (13)
10.23		Assignment of Operating Rights Interest between Olympic Energy Partners, LLC and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.24		Assignment of Operating Rights Interest between Juneau Exploration, LP and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.25		Partial Assignment of Oil and Gas Leases between Juneau Exploration, LP and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.26		Assignment of Operating Rights Interest between Juneau Exploration, LP and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.27		Assignment of Operating Rights Interest between Juneau Exploration, LP and Contango Operators, Inc., dated as of April 3, 2008. (14)
10.28		Partial Assignment of Oil and Gas Leases between Juneau Exploration, LP and Contango Operators, Inc., dated as of April 3, 2008. (14)
10.29		Assignment of Operating Rights Interest between Juneau Exploration, LP and Contango Operators, Inc., dated as of April 3, 2008. (14)
10.30		Assignment of Operating Rights Interest between Olympic Energy Partners, LLC and Contango Operators, Inc., dated as of April 3, 2008. (14)
10.31		Partial Assignment of Oil and Gas Leases between Olympic Energy Partners, LLC and Contango Operators, Inc. dated as of April 3, 2008. (14)
10.32		Assignment of Operating Rights Interest between Olympic Energy Partners, LLC and Contango Operators, Inc., dated as of April 3, 2008. (14)
10.33		Assignment of Overriding Royalty Interest between Dutch Royalty Investments, Land and Leasing, LP and Contango Operators, Inc., dated as of February 8, 2008. (15)
10.34		Assignment of Overriding Royalty Interest between Dutch Royalty Investments, Land and Leasing, LP and Contango Operators, Inc., dated as of February 8, 2008. (15)
10.35		Assignment of Overriding Royalty Interest between Dutch Royalty Investments, Land and Leasing, LP and Contango Operators, Inc., dated as of February 8, 2008. (15)
10.36		Assignment of Overriding Royalty Interest between Dutch Royalty Investments, Land and Leasing, LP and Contango Operators, Inc., dated as of February 8, 2008. (15)

10.37	Assignment of Overriding Royalty Interest between Dutch Royalty Investments, Land and Leasing, LP and Contango Operators, Inc., dated as of February 8, 2008. (15)
10.38	Assignment of Overriding Royalty Interest between Dutch Royalty Investments, Land and Leasing, LP and Contango Operators, Inc., dated as of February 8, 2008. (15)
10.39	Assignment of Overriding Royalty Interest between Dutch Royalty Investments, Land and Leasing, LP and Contango Operators, Inc., dated as of February 8, 2008. (15)
10.40	Amended and Restated Limited Liability Company Agreement of Republic Exploration LLC, dated April 1, 2008. (14)

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10.41		Amended and Restated Limited Liability Company Agreement of Contango Offshore Exploration LLC, dated April 1, 2008. (15)
10.42		$50,000,000 Amended and Restated Credit Agreement dated as of March 31, 2009 among Contango Oil & Gas Company, Contango Energy Company and Contango Operators Inc. as Borrowers, Guaranty Bank, as administrative agent and issuing lender, and the lenders party thereto from time to time. (17)
10.43	*	Contango Oil & Gas Company Annual Incentive Plan. (22)
10.44	*	Contango Oil & Gas Company 2009 Equity Compensation Plan. (22)
10.45		Conterra Joint Venture Development Agreement effective October 1, 2009 between Conterra Company and Patara Oil & Gas LLC. (18)
10.46		First Amended and Restated Limited Liability Company Agreement dated as of March 31, 2012. (23)
10.47		Advisory Agreement between Contango Oil & Gas Company and Juneau Exploration, L.P., dated as of April 5, 2012. (24)
10.48		Participation Agreement covering OCS-G 27927, Ship Shoal Block 263, South Addition, dated as of October 9, 2008 between Contango Offshore Exploration LLC and Contango Operators, Inc. †
10.49		Amendment to Participation Agreement covering OCS-G 27927, Ship Shoal Block 263, South Addition, dated as of October 7, 2009 between Contango Offshore Exploration LLC and Contango Operators, Inc. †
10.50		Amendment to Participation Agreement covering OCS-G 27927, Ship Shoal Block 263, South Addition, dated as of January 29, 2010 between Contango Offshore Exploration LLC and Contango Operators, Inc. †
10.51		Participation Agreement covering OCS-G 33596, Vermilion 170, dated as of July 1, 2010 between Republic Exploration LLC and Contango Operators, Inc. †
10.52		Participation Agreement covering OCS-G 33640, Ship Shoal 121; OCS-G 33641, Ship Shoal 122; and OCS-G 22701, Ship Shoal 134, dated as of July 1, 2010 between Republic Exploration LLC and Contango Operators, Inc. †
10.53		Amendment to Participation Agreement covering OCS-G 33640, Ship Shoal 121; OCS-G 33641, Ship Shoal 122; and OCS-G 22701, Ship Shoal 134, dated as of June 30, 2012 between Republic Exploration LLC and Contango Operators, Inc. †
10.54		Participation Agreement covering OCS-G 22738, South Timbalier 75, dated as of July 26, 2011 between Republic Exploration LLC and Contango Operators, Inc. †
10.55		Amendment to Participation Agreement covering OCS-G 22738, South Timbalier 75, dated as of August 21, 2012 between Republic Exploration LLC and Contango Operators, Inc. †
10.56		Participation Agreement covering Tuscaloosa Marine Shale, dated as of August 27, 2012 between Juneau Exploration LP and Contango Operators, Inc. †
10.57		Letter Agreement dated as of June 8, 2012 between Juneau Exploration LP and Contango Operators, Inc. †
10.58		Participation Agreement covering Central Gulf of Mexico Lease Sale 216/222, dated as of August 27, 2012 between Republic Exploration LLC and Contango Operators, Inc. †
10.59		Participation Agreement covering Central Gulf of Mexico Lease Sale 216/222, dated as of August 27, 2012 between Juneau Exploration LP and Contango Operators, Inc. †
10.60		Agreement to Purchase Overriding Royalty Interest, dated March 1, 2010 between Contango Offshore Exploration LLC and Juneau Exploration LP. †
14.1		Code of Ethics. †
21.1		List of Subsidiaries. †
21.2		Organizational Chart. †
23.1		Consent of William M. Cobb & Associates, Inc. †
23.2		Consent of Lonquist & Co. LLC. †
23.3		Consent of Grant Thornton LLP. †
31.1		Certification of Acting Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934. †
31.2		

	Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934. †
32.1	Certification of Acting Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. †
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. †
99.1	Report of William M. Cobb & Associates, Inc. †

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† Filed herewith.
* Indicates a management contract or compensatory plan or arrangement.

1. Filed as an exhibit to the Company’s Form 10-SB Registration Statement, as filed with the Securities and Exchange Commission on October 16, 1998.
2. Filed as an exhibit to the Company’s report on Form 10-QSB for the quarter ended September 30, 1999, as filed with the Securities and Exchange Commission on November 11, 1999.
3. Filed as an exhibit to the Company’s report on Form 8-K, dated August 24, 2000, as filed with the Securities and Exchange Commission of September 8, 2000.
4. Filed as an exhibit to the Company’s annual report on Form 10-KSB for the fiscal year ended June 30, 2000, as filed with the Securities and Exchange Commission on September 27, 2000.
5. Filed as an exhibit to the Company’s report on Form 8-K, dated December 1, 2000, as filed with the Securities and Exchange Commission on December 15, 2000.
6. Filed as an exhibit to the Company’s report on Form 8-K, dated January 4, 2002, as filed with the Securities and Exchange Commission on January 8, 2002.
7. Filed as an exhibit to the Company’s report on Form 10-QSB for the quarter ended March 31, 2002, as filed with the Securities and Exchange Commission on February 14, 2002.
8. Filed as an exhibit to the Company’s report on Form 10-QSB for the quarter ended December 31, 2002, dated November 14, 2002, as filed with the Securities and Exchange Commission.
9. Filed as an exhibit to the Company’s annual report on Form 10-KSB for the fiscal year ended June 30, 2003, as filed with the Securities and Exchange Commission on September 22, 2003.
10. Filed as an exhibit to the Company’s report on Form 8-K, dated September 2, 2005, as filed with the Securities and Exchange Commission on September 8, 2005.
11. Filed as an exhibit to the Company’s report on Form 10-K for the fiscal year ended June 30, 2005, as filed with the Securities and Exchange Commission on September 13, 2005.
12. Filed as an exhibit to the Company’s report on Form 10-Q for the quarter ended September 30, 2006, dated November 8, 2006, as filed with the Securities and Exchange Commission.
13. Filed as an exhibit to the Company’s report on Form 8-K, dated January 3, 2008, as filed with the Securities and Exchange Commission on January 9, 2008.
14. Filed as an exhibit to the Company’s report on Form 8-K, dated April 3, 2008, as filed with the Securities and Exchange Commission on April 9, 2008.
15. Filed as an exhibit to the Company’s report on Form 10-K for the fiscal year ended June 30, 2008, as filed with the Securities and Exchange Commission on August 29, 2008.
16. Filed as an exhibit to the Company’s report on Form 8-K, dated September 30, 2008, as filed with the Securities and Exchange Commission on October 1, 2008.
17. Filed as an exhibit to the Company’s report on Form 10-Q for the quarter ended March 31, 2009, as filed with the Securities and Exchange Commission on May 11, 2009.
18. Filed as an exhibit to the Company’s report on Form 8-K, dated October 22, 2009, as filed with the Securities and Exchange Commission on October 28, 2009.
19. Filed as an exhibit to the Company’s report on Form 8-K, dated October 20, 2010 as filed with the Securities and Exchange Commission on October 25, 2010.
20. Filed as an exhibit to the Company’s report on Form 10-Q for the quarter ended September 30, 2010, as filed with the Securities and Exchange Commission on November 9, 2010.
21. Filed as an exhibit to the Company’s report on Form 8-K, dated May 13, 2011 as filed with the Securities and Exchange Commission on May 18, 2011.
22. Filed as an exhibit to the Company’s report on Form 10-K for the fiscal year ended June 30, 2010, as filed with the Securities and Exchange Commission on September 13, 2010.
23.

Filed as an exhibit to the Company's report on Form 8-K, dated as of March 31, 2012, as filed with the Securities and Exchange Commission on April 5, 2012.

24. Filed as an exhibit to the Company's report on Form 8-K, dated as of April 10, 2012, as filed with the Securities and Exchange Commission on April 11, 2012.

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SIGNATURES

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

CONTANGO OIL & GAS COMPANY

/s/ BRAD JUNEAU	/s/ SERGIO CASTRO	/s/ YAROSLAVA MAKALSKAYA
Brad Juneau	Sergio Castro	Yaroslava Makalskaya
Acting Chief Executive Officer	Chief Financial Officer	Chief Accounting Officer
(principal executive officer)	(principal financial officer)	(principal accounting officer)

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

Name	Title	Date
/s/ B.A. BERILGEN B.A. Berilgen	Director	August 29, 2012
/s/ JAY D. BREHMER Jay D. Brehmer	Director	August 29, 2012
/s/ BRAD. JUNEAU Brad Juneau	Director	August 29, 2012
/s/ CHARLES M. REIMER Charles M. Reimer	Director	August 29, 2012
/s/ STEVEN L. SCHOONOVER Steven L. Schoonover	Director	August 29, 2012

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Contango Oil & Gas Company

We have audited the accompanying consolidated balance sheets of Contango Oil & Gas Company (a Delaware corporation) and subsidiaries (the "Company") as of June 30, 2012 and 2011, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended June 30, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Contango Oil & Gas Company and subsidiaries as of June 30, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2012 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of June 30, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated August 29, 2012 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Houston, Texas
August 29, 2012

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)
ASSETS

	June 30, 2012	2011
CURRENT ASSETS:		
Cash and cash equivalents	$129,983	$150,007
Accounts receivable:		
Trade receivable	29,688	43,967
Joint interest billings	4,768	6,818
Income taxes	4,510	94
Other receivables	242	978
Prepaid expenses	4,952	2,375
Other	1,070	639
Total current assets	175,213	204,878
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	561,713	552,556
Unproved properties	12,485	7,625
Furniture and equipment	213	227
Accumulated depreciation, depletion and amortization	(178,081)	(129,702)
Total property, plant and equipment, net	396,330	430,706
OTHER ASSETS:		
Investment in affiliates	52,827	935
Other	284	411
TOTAL ASSETS	$624,654	$636,930

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)
LIABILITIES AND SHAREHOLDERS' EQUITY

	June 30, 2012	2011
CURRENT LIABILITIES:		
Accounts payable	$3,084	$11,857
Royalties and revenue payable	22,098	39,222
Accrued liabilities	6,796	9,745
Joint interest advances	—	3,995
Accrued exploration and development	2,334	6,002
Income tax payable	—	6,942
Other current liabilities	—	461
Total current liabilities	34,312	78,224
DEFERRED TAX LIABILITY	118,010	123,472
ASSET RETIREMENT OBLIGATION	7,993	8,611
COMMITMENTS AND CONTINGENCIES (NOTE 10)		
SHAREHOLDERS' EQUITY:		
Common stock, $0.04 par value, 50 million shares authorized, 20,135,107 shares issued and 15,292,448 shares outstanding at June 30, 2012, 20,135,107 shares issued and 15,664,666 shares outstanding at June 30, 2011	805	805
Additional paid-in capital	79,024	79,278
Treasury stock at cost (4,842,659 shares at June 30, 2012 and 4,470,441 shares at June 30, 2011)	(112,207)	(91,788)
Retained earnings	496,717	438,328
Total shareholders' equity	464,339	426,623
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$624,654	$636,930

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

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	Year Ended June 30,		
	2012	2011	2010
REVENUES:			
Natural gas and oil sales	$179,272	$201,721	$159,010
Total revenues	179,272	201,721	159,010
EXPENSES:			
Operating expenses	25,183	25,691	16,692
Exploration expenses	346	9,751	20,850
Depreciation, depletion and amortization	49,052	52,198	34,521
Impairment of natural gas and oil properties	—	1,786	952
General and administrative expense	10,418	12,341	4,599
Total expenses	84,999	101,767	77,614
Loss from investment in affiliates (net of tax of $241)	(449)	—	—
Other income (expense)	(312)	(157)	511
NET INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	93,512	99,797	81,907
Provision for income taxes	(34,299)	(35,338)	(31,741)
INCOME FROM CONTINUING OPERATIONS	59,213	64,459	50,166
DISCONTINUED OPERATIONS (NOTE 5)			
Discontinued operations, net of income taxes	(824)	574	(480)
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$58,389	$65,033	$49,686
NET INCOME (LOSS) PER SHARE:			
Basic			
Continuing operations	$3.84	$4.11	$3.17
Discontinued operations	(0.05)	0.04	(0.03)
Total	$3.79	$4.15	$3.14
Diluted			
Continuing operations	$3.84	$4.10	$3.11
Discontinued operations	(0.05)	0.04	(0.03)
Total	$3.79	$4.14	$3.08
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
Basic	15,423	15,665	15,831
Diluted	15,425	15,713	16,157

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

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended June 30,		
	2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:			
Income from continuing operations	$59,213	$64,459	$50,166
Plus income (loss) from discontinued operations, net of income taxes	(824)	574	(480)
Net income	58,389	65,033	49,686
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	49,052	59,337	35,374
Impairment of natural gas and oil properties	1,031	2,315	952
Exploration expenses	—	9,657	20,502
Deferred income taxes	(5,716)	(7,819)	19,399
Loss (gain) on sale of assets	169	(1,813)	(113)
Loss from investment in affiliates	690	—	—
Stock-based compensation	3	1,276	667
Tax benefit from exercise of stock options	(254)	(502)	(79)
Changes in operating assets and liabilities:			
Decrease (increase) in accounts receivable and other	14,280	(2,029)	(9,129)
Decrease (increase) in prepaids and other receivables	(1,840)	1,671	(3,234)
Increase (decrease) in accounts payable and advances from joint owners	(27,842)	(5,718)	14,846
Increase (decrease) in other accrued liabilities	(3,413)	7,142	301
Increase (decrease) in income taxes payable, net	(11,357)	11,917	662
Other	379	91	(1,646)
Net cash provided by operating activities	73,571	140,558	128,188
CASH FLOWS FROM INVESTING ACTIVITIES:			
Natural gas and oil exploration and development expenditures	(20,847)	(69,993)	(97,703)
Advance under note receivable	(500)	—	—
Repayment of note receivable	500	2,028	—
Investments in affiliates	(53,406)	(3,959)	—
Distributions from affiliates	823	—	—
Proceeds from the sale of assets	—	38,671	—
Net cash used in investing activities	(73,430)	(33,253)	(97,703)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Dividends	—	(6)	—
Purchase of common stock	(20,419)	(9,769)	(23,380)
Proceeds from exercised options	—	—	914
Tax benefit from exercise/cancellation of stock options	254	502	79
Debt issuance costs	—	(494)	—
Net cash used in financing activities	(20,165)	(9,767)	(22,387)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(20,024)	97,538	8,098
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	150,007	52,469	44,371
CASH AND CASH EQUIVALENTS, END OF PERIOD	$129,983	$150,007	$52,469

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid for taxes, net of cash received	$50,687	$31,876	$11,535
Cash paid for interest	$121	$60	$250

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

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
(in thousands)

	Common Stock		Additional Paid-in	Treasury	Retained	Total Shareholders'
	Shares	Amount	Capital	Stock	Earnings	Equity
Balance at June 30, 2009	15,830	$785	$76,322	$(58,639)	$330,896	$349,364
Exercise of stock options	344	14	900	—	—	914
Tax benefit from exercise of stock options	—	—	79	—	—	79
Amortization of restricted stock	—	—	72	—	—	72
Treasury shares at cost	(489)	—	—	(23,380)	—	(23,380)
Stock option expense	—	—	595	—	—	595
Net income	—	—	—	—	49,686	49,686
Balance at June 30, 2010	15,685	$799	$77,968	$(82,019)	$380,582	$377,330
Exercise of stock options	153	6	(6)	—	—	—
Tax benefit from exercise of stock options	—	—	502	—	—	502
Treasury shares at cost	(173)	—	—	(9,769)	—	(9,769)
Stock option expense	—	—	814	—	—	814
Dividends	—	—	—	—	(7,287)	(7,287)
Net income	—	—	—	—	65,033	65,033
Balance at June 30, 2011	15,665	$805	$79,278	$(91,788)	$438,328	$426,623
Tax benefit from exercise of stock options	—	—	(254)	—	—	(254)
Treasury shares at cost	(372)	—	—	(20,419)	—	(20,419)
Net income	—	—	—	—	58,389	58,389
Balance at June 30, 2012	15,293	$805	$79,024	$(112,207)	$496,717	$464,339

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Business
Contango Oil & Gas Company (collectively with its subsidiaries, “Contango” or the “Company”) is a Houston-based, independent natural gas and oil company. The Company’s business is to explore, develop, produce and acquire natural gas and oil properties primarily onshore and offshore in the Gulf of Mexico in water-depths of less than 300 feet.
2. Summary of Significant Accounting Policies
Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. The most significant estimates include income taxes, stock-based compensation, reserve estimates and impairment of natural gas and oil properties. Actual results could differ from those estimates.
Revenue Recognition. Revenues from the sale of natural gas and oil produced are recognized upon the passage of title, net of royalties. Revenues from natural gas production are recorded using the sales method. When sales volumes exceed the Company’s entitled share, an overproduced imbalance occurs. To the extent the overproduced imbalance exceeds the Company’s share of the remaining estimated proved natural gas reserves for a given property, the Company records a liability. As of June 30, 2012 and 2011, the Company had no significant imbalances.
Cash Equivalents. Cash equivalents are considered to be highly liquid investment grade debt investments having an original maturity of 90 days or less. As of June 30, 2012, the Company had approximately $130 million in cash and cash equivalents, all of which was held in non-interest bearing accounts, fully insured by the Federal Deposit Insurance Corporation ("FDIC").
Accounts Receivable. The Company sells natural gas and crude oil to a limited number of customers. In addition, the Company participates with other parties in the operation of natural gas and crude oil wells. Substantially all of the Company’s accounts receivables are due from either purchasers of natural gas and crude oil or participants in natural gas and crude oil wells for which the Company serves as the operator. Generally, operators of natural gas and crude oil properties have the right to offset future revenues against unpaid charges related to operated wells.
The allowance for doubtful accounts is an estimate of the losses in the Company’s accounts receivable. The Company periodically reviews the accounts receivable from customers for any collectability issues. An allowance for doubtful accounts is established based on reviews of individual customer accounts, recent loss experience, current economic conditions, and other pertinent factors. Amounts deemed uncollectible are charged to the allowance.
Accounts receivable allowance for bad debt was $0 at June 30, 2012 and 2011. At June 30, 2012 and 2011, the carrying value of the Company’s accounts receivable approximated fair value.
Net Income per Common Share. Basic net income per common share is computed by dividing income attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net income per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. See Note 6 – Net Income Per Common Share for the calculations of basic and diluted net income per common share.

Income Taxes. The Company follows the liability method of accounting for income taxes under which deferred tax assets and liabilities are recognized for the future tax consequences of (i) temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements and (ii) operating loss and tax credit carryforwards for tax purposes. Deferred tax assets are reduced by a valuation allowance when, based upon management’s estimates, it is more likely than not that a portion of the deferred tax assets will not be realized in a future period. The Company reviews its tax positions quarterly for tax uncertainties. The Company did not have significant uncertain tax positions as of June 30, 2012. The amount of unrecognized tax benefits did not materially change from June 30, 2011. The amount of unrecognized tax benefits may change in the next twelve months; however, we do not expect the change to have a significant impact on our financial position or results of operations. The Company includes interest and penalties in interest income and general and administrative expenses, respectively, in its statement of operations.

The Company files income tax returns in the United States and various state jurisdictions. The Company's federal tax returns for 2009 – 2011, and state tax returns for 2008 - 2011, remain open for examination by the taxing authorities in the respective jurisdictions where those returns were filed.

Concentration of Credit Risk. Substantially all of the Company's accounts receivable result from natural gas and oil sales or joint interest billings to a limited number of third parties in the natural gas and oil industry. This concentration of customers and joint interest owners may impact the Company's overall credit risk in that these entities may be similarly affected by changes in economic and other conditions.

Consolidated Statements of Cash Flows. Significant transactions, such as issuing restricted stock or stock options, may occur that do not directly affect cash balances and, as such, are not disclosed in the Consolidated Statements of Cash Flows. Certain such non-cash transactions are disclosed in the Statements of Shareholders' Equity and footnotes to the Consolidated Financial Statements.

Fair Value of Financial Instruments. The carrying amounts of the Company's short-term financial instruments, including cash equivalents, short-term investments, trade accounts receivable and accounts payable, approximate their fair values based on the short maturities of those instruments.

Successful Efforts Method of Accounting. The Company follows the successful efforts method of accounting for its natural gas and oil activities. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Exploratory drilling costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploratory costs, such as seismic costs and other geological and geophysical expenses, are expensed as incurred. Depreciation, depletion and amortization is calculated on a field by field basis using the unit of production method, with lease acquisition costs amortized over total proved reserves and other capitalized costs amortized over proved developed reserves.

Impairment of Long-Lived Assets. When circumstances indicate that proved properties may be impaired, the Company compares expected undiscounted future cash flows on a field by field basis to the unamortized capitalized cost of the asset. If the estimated future undiscounted cash flows, based on the Company's estimate of future reserves, natural gas and oil prices and operating costs and anticipated production levels from oil and natural gas reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to its fair value. The Company did not recognize impairment of proved properties for the fiscal years ended June 30, 2012, 2011 or 2010.

Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, and any such impairment is charged to expense in the period. The Company did not recognize any impairment of unproven properties for the year ended June 30, 2012. For the year ended June 30, 2011, the Company recorded impairment expense of approximately $1.8 million, related to the relinquishment of 14 unproved lease blocks owned by Republic Exploration, LLC ("REX") and Contango Offshore Exploration, LLC ("COE"). For the fiscal year ended June 30, 2010, the Company recorded $1.0 million in impairment charges related to the expiration and relinquishment of six unproved lease blocks owned by REX and COE.

Discontinued Operations. An integral and on-going part of our business strategy is to sell our proved reserves from time to time in order to generate additional capital to reinvest in our onshore and offshore exploration programs. When applicable, the disposition of these assets is classified as discontinued operations for all periods presented.

Principles of Consolidation. The Company's consolidated financial statements include the accounts of Contango Oil & Gas Company and its subsidiaries, after elimination of all material intercompany balances and transactions. Wholly-owned subsidiaries are fully consolidated. Exploration and development affiliates not wholly owned, such as REX, are not controlled by the Company and are proportionately consolidated.

Other Investments. Contango's 19.5% ownership of Moblize Inc. ("Moblize") and 2.0% ownership of Alta Energy Canada Partnership ("Alta Energy") are accounted for using the cost method. Under the cost method, Contango records an investment in the stock of an investee at cost, and recognizes dividends received as income. Dividends received in excess of earnings subsequent to the date of investment are considered a return of investment and are recorded as reductions of cost of the investment. In fiscal year 2010, the Company recognized a $190,000 impairment of its investment in Moblize.

The Company's Chairman and the Company's President and Acting Chief Executive Officer both sit on the board of directors of Exaro Energy III LLC ("Exaro") and have significant influence, but not control, over the company. As a result, the Company's 45% ownership in Exaro is accounted for using the equity method. Under the equity method, the Company's proportionate share of Exaro's net income increases our investment in our consolidated balance sheet, while a net loss or payment of dividends decreases our investment. In our consolidated statement of operations, our proportionate share of Exaro's net income or loss is reported as a single-line item. For the fiscal year ended June 30, 2012, the Company recorded a loss from affiliates related to our Exaro investment of approximately $0.5 million, net of taxes of approximately $0.2 million.

Reclassifications. Certain reclassifications have been made to the fiscal year 2011 and 2010 amounts in order to conform to the 2012 presentation. These reclassifications were not material.

Stock-Based Compensation. The Company applies the fair value based method to account for stock based compensation. Under this method, compensation cost is measured at the grant date based on the fair value of the award and is recognized over the award vesting period. The Company classifies the benefits of tax deductions in excess of the compensation cost recognized for the options (excess tax benefit) as financing cash flows. The fair value of each award is estimated as of the date of grant using the Black-Scholes option-pricing model.

Liability Accounting for Stock Options. In November 2010, the Company's Board of Directors approved the immediate vesting of all outstanding stock options and authorized management to net-settle any outstanding stock options in cash. As a result, the Company reclassified all outstanding stock options from equity instruments to liability instruments. This resulted in recognizing a liability equal to the portion of each award attributable to past service multiplied by the modified award's fair value. The liability for the outstanding stock options is based on the fair value of each award evaluated at the end of each quarter using the Black-Scholes option-pricing model. To the extent that the liability exceeds the amount recognized at the end of the previous period, the difference is recognized as compensation cost in the statement of operations for each period until the stock options are settled.

Derivative Instruments and Hedging Activities. The Company did not enter into any derivative instruments or hedging activities for the fiscal years ended June 30, 2012, 2011 or 2010, nor did we have any open commodity derivative contracts at June 30, 2012 or 2011.

Recent Accounting Pronouncements. In December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2011-11 Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities (ASU 2011-11). ASU 2011-11 requires that an entity disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU 2011-11 is effective for annual and interim periods beginning on or after January 1, 2013. We are currently evaluating the provisions of ASU 2011-11 and assessing the impact, if any, it may have on the disclosures in our financial statements.

3. Natural Gas and Oil Exploration and Production Risk

The Company's future financial condition and results of operations will depend upon prices received for its natural gas and oil production and the cost of finding, acquiring, developing and producing reserves.

Substantially all of its production is sold under various terms and arrangements at prevailing market prices. Prices for natural gas and oil are subject to fluctuations in response to changes in supply, market uncertainty and a variety of other factors beyond the Company's control.

Other factors that have a direct bearing on the Company's financial condition are uncertainties inherent in estimating natural gas and oil reserves and future hydrocarbon production and cash flows, particularly with respect to wells that have not been fully tested and with wells having limited production histories; the timing and costs of our future drilling; development and abandonment activities; access to additional capital; changes in the price of natural gas and oil; availability and cost of services and equipment; and the presence of competitors with greater financial resources and capacity.

4. Concentration of Credit Risk

The customer base for the Company is concentrated in the natural gas and oil industry. Major purchasers of our natural gas, oil and natural gas liquids for the fiscal year ended June 30, 2012 were Shell Trading US Company (25%), NJR Energy Services (13%), ConocoPhillips Company (22%), Enterprise Products Operating LLC (14%), ExxonMobil Oil Corp. (11%), and TransLouisiana Gas Pipeline, Inc. (8%). Our sales to these companies are not secured with letters of credit and in the event of non-payment, we could lose up to two months of revenues. The loss of two months of revenues would have a material adverse effect on our financial position. There are numerous other potential purchasers of our production.

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5. Discontinued Operations

Joint Venture Assets
In October 2009, the Company entered into a joint venture with Patara Oil & Gas LLC (“Patara”) to develop proved undeveloped Cotton Valley gas reserves in Panola County, Texas. B.A. Berilgen, a member of the Company’s board of directors, is the Chief Executive Officer of Patara. On May 13, 2011 the Company sold substantially all of its onshore Texas assets to Patara Oil & Gas LLC (“Patara”) for an aggregate purchase price of $40 million ($38.7 million after adjustments). The properties were sold effective April 1, 2011 and included: (i) the Company’s 90% interest and 5% overriding royalty interest in the 21 wells drilled under the joint venture with Patara (the “Joint Venture Assets”); (ii) the Company’s 100% working interest (72.5% net revenue interest) in Rexer #1 drilled in south Texas; and (iii) a 75% working interest (54.4% net revenue interest) in Rexer-Tusa #2. The Company has accounted for the sale of the Joint Venture Assets as discontinued operations as of June 30, 2011 and reclassified the results of its operations and the loss on disposition to discontinued operations for all periods presented.

The Joint Venture Assets had proved reserves of approximately 16,700 Mmcfe, net to Contango. The summarized financial results for the Joint Venture Assets for the periods ended June 30, 2012 and 2011 are as follows:
Results of Operations:

	June 30, 2012 (thousands)	2011	2010
Revenues	$—	$8,055	$1,671
Operating expenses	(40)	(1,613)	(348)
Depletion expenses	—	(4,106)	(853)
Impairment and other expenses	—	(527)	(2)
Loss on sale	—	(651)	—
Income (loss) before income taxes	$(40)	$1,158	$468
Benefit (provision) for income taxes	14	(618)	(164)
Income (loss) from discontinued operations, net of income taxes	$(26)	$540	$304

Rexer Assets
In October 2011, the Company sold its remaining 25% working interest (18.4% net revenue interest) in Rexer-Tusa #2 for $10,000 to Patara (together with the 75% working interest sold in Rexer-Tusa #2 and the 100% working interest sold in Rexer #1, the "Rexer Assets"). The sale was effective October 1, 2011. The Company has accounted for the sale of the Rexer Assets as discontinued operations as of June 30, 2012 and reclassified the results of operations for the Rexer Assets for each of the periods presented as follows:

	June 30, 2012 (thousands)	2011
Revenues	$6	$2,056
Operating expenses	(16)	(298)
Depletion expenses	(11)	(3,033)
Impairment of natural gas and oil properties	(1,031)	—
Exploration expenses	(7)	—
Loss on sale	(169)	$(273)

Loss before income taxes	$(1,228)	$(1,548)
Benefit for income taxes	430	542
Loss from discontinued operations, net of income taxes	$(798)	$(1,006)

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Contango Mining Company
On September 29, 2010, Contango ORE, Inc. ("CORE"), then a wholly-owned subsidiary of the Company, filed with the Securities and Exchange Commission a Registration Statement on Form 10 which became effective November 29, 2010. Following the effective date, CORE acquired the assets and assumed the liabilities of Contango Mining Company ("Contango Mining"), another wholly-owned subsidiary of the Company. Additionally, subsequent to the effective date, the Company contributed $3.5 million of cash to CORE. In exchange, CORE issued 1,566,367 shares of its common stock to the Company in addition to the 100 shares which the Company held prior to that date. The Company distributed all its shares of CORE, valued at approximately $7.3 million, to its stockholders of record as of October 15, 2010 on the basis of one share of common stock of CORE for each ten shares of the Company's common stock then outstanding. In addition to the distribution of shares of CORE, the Company paid $6,213 in cash to its stockholders of record in exchange for partial shares. As of June 30, 2012 and 2011, the assets and liabilities of Contango Mining were excluded from the Company's financial statements.

Results of operations of Contango Mining for the fiscal year ended June 30, 2011 and for each of the previous periods are included in discontinued operations in the Company's Statement of Operations. No income or expense related to CORE were recognized for the year ended June 30, 2012. The summarized financial results for Contango Mining for the fiscal years ended June 30, 2011 and 2010 were as follows:
Operating Results:

	June 30,	
	2011	2010
	(thousands)	
Revenues	$—	$—
Exploration expenses	(983)	(1,102)
General and administrative expenses	(154)	—
Gain on sale	2,737	—
Income (loss) before income taxes	$1,600	$(1,102)
Benefit (provision) for income taxes	(560)	318
Income (loss) from discontinued operations, net of income taxes	$1,040	$(784)

The gain on sale of discontinued operations for 2011 represents the difference between $7.3 million, the fair value of the shares of CORE distributed to the Company's shareholders, and the historical value of the assets and liabilities transferred to CORE on or subsequent to November 29, 2010.
6. Net Income Per Common Share
A reconciliation of the components of basic and diluted net income per common share for the fiscal years ended June 30, 2012, 2011 and 2010 is presented below:

	Year Ended June 30, 2012		
(thousands, except per share amounts)	Net Income	Shares	Per Share
Income from continuing operations	$59,213	15,423	$3.84
Discontinued operations, net of income taxes	(824)	15,423	(0.05)
Basic Earnings per Share:			
Net income attributable to common stock	$58,389	15,423	$3.79
Effect of potential dilutive securities:			
Stock options, net of shares assumed purchased	—	2	
Income from continuing operations	$59,213	15,425	$3.84
Discontinued operations, net of income taxes	(824)	15,425	(0.05)

Diluted Earnings per Share:			
Net income attributable to common stock	$58,389	15,425	$3.79

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	Year Ended June 30, 2011		
(thousands, except per share amounts)	Net Income	Shares	Per Share
Income from continuing operations	$64,459	15,665	$4.11
Discontinued operations, net of income taxes	574	15,665	0.04
Basic Earnings per Share:			
Net income attributable to common stock	$65,033	15,665	$4.15
Effect of potential dilutive securities:			
Stock options, net of shares assumed purchased	—	48	
Income from continuing operations	$64,459	15,713	$4.10
Discontinued operations, net of income taxes	574	15,713	0.04
Diluted Earnings per Share:			
Net income attributable to common stock	$65,033	15,713	$4.14

	Year Ended June 30, 2010		
(thousands, except per share amounts)	Net Income	Shares	Per Share
Income from continuing operations	$50,166	15,831	$3.17
Discontinued operations, net of income taxes	(480)	15,831	(0.03)
Basic Earnings per Share:			
Net income attributable to common stock	$49,686	15,831	$3.14
Effect of potential dilutive securities:			
Stock options, net of shares assumed purchased	—	326	
Income from continuing operations	$50,166	16,157	$3.11
Discontinued operations, net of income taxes	(480)	16,157	(0.03)
Diluted Earnings per Share:			
Net income attributable to common stock	$49,686	16,157	$3.08

Options to purchase 70,000 shares of common stock were outstanding as of June 30, 2010 but were not included in the computation of diluted earnings per share for the fiscal year ended June 30, 2010. These options were excluded because either (i) the options' exercise price was greater than the average market price of the common shares, or (ii) application of the treasury method to in-the-money options made some of the options anti-dilutive.

7. Change in Ownership of Partially-Owned Subsidiaries and Overriding Royalties

Prior to its dissolution on June 1, 2010, in his capacity as sole manager of the general partner of Juneau Exploration LLC ("JEX"), Mr. Juneau controlled the activities of COE, an entity then owned 65.63% by Contango and 34.37% by JEX. COE generated and evaluated offshore exploration prospects and had historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specified each participant's working interest, net revenue interest, and described when such interests were earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX. The Company proportionately consolidated the results of COE in its consolidated financial statements.

Immediately prior to its dissolution, COE owed the Company $5.9 million in principal and interest under a promissory note (the "COE Note") payable on demand. In connection with the dissolution, the Company assumed its 65.6% share of the obligation under the COE Note, while JEX assumed the remaining 34.4%, or approximately $2 million. This $2 million was paid back to the Company during the fiscal year ended June 30, 2011.

8. Income Taxes

Actual income tax expense from continuing operations differs from income tax expense from continuing operations computed by applying the U.S. federal statutory corporate rate of 35 percent to pretax income as follows:

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	Year Ended June 30,								
	2012			2011			2010		
				(thousands)					
Provision at statutory tax rate	$32,644	35.0	%	$34,929	35.00	%	$28,445	35.0	%
State income tax provision, net of federal benefit	1,712	1.84	%	2,985	3.04	%	1,415	1.74	%
Permanent differences	(746)	(0.80	)%	(2,678)	(2.73	)%	(465)	(0.57	)%
Other	447	0.48	%	102	0.10	%	2,346	2.89	%
Income tax provision	$34,057	36.52	%	$35,338	35.41	%	$31,741	39.06	%

The provision (benefit) for income taxes from continuing operations for the periods indicated are comprised of the following:

	Year Ended June 30,		
	2012	2011	2010
Current:		(thousands)	
Federal	$36,824	$34,256	$16,564
State	2,783	3,502	598
Total	$39,607	$37,758	$17,162
Deferred:			
Federal	$(5,369)	$(1,405)	$13,503
State	(181)	(1,015)	1,076
Total	$(5,550)	$(2,420)	$14,579
Total:			
Federal	$31,455	$32,851	$30,067
State	2,602	2,487	1,674
Total	$34,057	$35,338	$31,741

The net deferred tax liability is comprised of the following:

	Year Ended June 30,		
	2012	2011	2010
		(thousands)	
Deferred tax liability:			
Temporary basis differences in natural gas and oil properties and other	$(118,010)	$(123,472)	$(131,291)
Net deferred tax liability	$(118,010)	$(123,472)	$(131,291)

9. Long-Term Debt

On October 22, 2010, the Company completed the arrangement of a secured revolving credit agreement with Amegy Bank (the "Credit Agreement") to replace its expiring credit agreement with BBVA Compass Bank. The Credit Agreement currently has a $40 million hydrocarbon borrowing base and is available to fund the Company's exploration and development activities, as well as repurchase shares of common stock, pay dividends, and fund working capital as needed. The Credit Agreement is secured by substantially all of the assets of the Company. Borrowings under the Credit Agreement bear interest at LIBOR plus 2.5%, subject to a LIBOR floor of 0.75%. The principal is due October 1, 2014, and may be prepaid at any time with no prepayment penalty. An arrangement fee of

$300,000 was paid in connection with the facility and a commitment fee of 0.125% is owed on unused borrowing capacity. The Credit Agreement contains customary covenants including limitations on our current ratio and additional indebtedness. As of June 30, 2012 and 2011, the Company was in compliance with all covenants and had no amounts outstanding under the Credit Agreement.

The Company’s $50 million hydrocarbon borrowing base secured revolving credit facility with BBVA Compass expired in October 2010 (the "Compass Agreement"). The credit facility was secured by substantially all of the Company's assets. Borrowings under the Compass Agreement carried interest at LIBOR plus 2.0% per annum. An arrangement fee of 0.5%, or $250,000, was paid in connection with the facility and a commitment fee of 0.5% was paid on the unused commitment amount.

10. Commitments and Contingencies

Contango pays delay rentals on its offshore leases and leases its office space and certain other equipment. In November 2010, the Company expanded its office space and extended its office lease agreement through December 31, 2015. As of June 30, 2012, minimum future lease payments for delay rentals and operating leases for our fiscal years are as follows:

Fiscal years ending June 30,	
	(thousands)
2013	$370
2014	364
2015	359
2016	166
2017 and thereafter	—
Total	$1,259

The amount incurred under operating leases and delay rentals during the years ended June 30, 2012, 2011 and 2010 was approximately $423,000, $288,000, and $692,000, respectively. Additionally, as of June 30, 2012, the Company will be required to pay approximately $8.8 million for remaining leasehold costs and rental payments for the 6 lease blocks bid on at the Central Gulf of Mexico Lease Sale 216/222.

Additionally, as of June 30, 2012, we have committed to invest $8.4 million in Alta Energy to acquire, explore, develop and operate onshore unconventional shale operated and non-operated oil and natural gas assets, as well as committed to invest $41.2 million with Exaro Energy III, LLC to develop onshore natural gas assets.

In July 2011 and July 2012, the Company granted year-end bonuses to employees. A portion of these bonuses were paid immediately and the remainder will vest and be paid over 2 years to incentivize employees to remain with the Company. As of June 30, 2012, approximately $2.3 million of compensation remained to be vested. Of this amount, approximately $1.9 million shall vest and be paid on June 30, 2013 and approximately $0.4 million will vest and be paid on June 30, 2014, as long as the employees are employed by the Company on the vesting date.

No significant legal proceedings are pending which are expected to have a material adverse effect on the Company. The Company is unaware of any potential claims or lawsuits involving environmental, operating or corporate matters which are expected to have a material adverse effect on the Company's financial position or results of operation.

11. Asset Retirement Obligation

Asset Retirement Obligation. The Company accounts for its retirement obligation of long lived assets by recording the net present value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred. When the liability is initially recorded, a company increases the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. Activities related to the Company's ARO during the year ended June 30, 2012 and 2011 were as follows:

	Year Ended June 30,	
	2012	2011
	(thousands)	
Balance as of July 1	$8,611	$5,157
Liabilities incurred during period	53	1,613
Liabilities settled during period	(238)	(157)
Accretion	507	386
Change in estimate	(940)	1,612
Balance as of June 30	$7,993	$8,611

12. Stock Based Compensation

The Company's 1999 Stock Incentive Plan (the "1999 Plan") expired in August 2009. There are no outstanding options issued under the 1999 Plan.

On September 15, 2009, the Company's Board of Directors (the "Board") adopted the Contango Oil & Gas Company 2009 Equity Compensation Plan (the "2009 Plan"), which was approved by shareholders on November 19, 2009. Under the 2009 Plan, the Board may grant restricted stock and option awards to officers, directors, employees or consultants of the Company. Awards made under the 2009 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Board.

Stock Options.

Under the 2009 Plan, the Company may issue up to 1,500,000 shares of common stock with an exercise price of each option equal to or greater than the market price of the Company's common stock on the date of grant. The Company may grant key employees both incentive stock options intended to qualify under Section 422 of the Internal Revenue Code of 1986, as amended, and stock options that are not qualified as incentive stock options. Stock option grants to non-employees, such as directors and consultants, can only be stock options that are not qualified as incentive stock options. Options generally expire after 5 or 10 years. The vesting schedule varies, and can vest over a 2, 3 or 4-year period. As of June 30, 2012, there were no options outstanding under the 2009 Plan.

A summary of the status of stock options granted under the 1999 Plan and 2009 Plan as of June 30, 2012, 2011 and 2010, and changes during the fiscal years then ended, is presented in the table below:

	Year Ended June 30,					
	2012		2011		2010	
	Shares Under Options	Weighted Average Exercise Price	Shares Under Options	Weighted Average Exercise Price	Shares Under Options	Weighted Average Exercise Price
Outstanding, beginning of year	45,000	$54.21	305,334	$28.61	685,167	$16.49
Granted	—	$—	—	$—	25,000	$49.29
Exercised	—	$—	(152,544)	$21.38	(344,229)	$9.24
Forfeited (1)	(45,000)	$54.21	(107,790)	$28.14	(60,604)	$10.20
Outstanding, end of year	—	$—	45,000	$54.21	305,334	$28.61
Aggregate intrinsic value ($000)	$—		$190		$4,928	
Exercisable, end of year	—	$—	45,000	$54.21	240,334	$22.74
Aggregate intrinsic value ($000)	$—		$190		$5,290	
Available for grant, end of year	1,475,000		1,475,000		2,475,000	

Weighted average fair value of options granted during the year (2)	$—	$—	$15.39

(1) For the fiscal year ended June 30, 2012, forfeited options consist of options that were net-settled for cash with the Company. For the fiscal year ended June 30, 2011 and 2010, forfeited options relate to options surrendered under a cashless exercise, with immediate sale to the Company.

(2) The fair value of each option is estimated as of the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions used for grants during the years ended June 30, 2010: (i) risk-free interest rate of 0.25 percent; (ii) expected life of 5 years; (iii) expected volatility of 35 percent; and (iv) expected dividend yield of zero percent.

Under the fair value method of accounting for stock options, cash flows from the exercise of stock options resulting from tax benefits in excess of recognized cumulative compensation cost (excess tax benefits) are classified as financing cash flows. For the fiscal years ended June 30, 2012, 2011 and 2010, approximately $0.3 million, $0.5 million, and $0.1 million, respectively, of such excess tax benefits were classified as financing cash flows. See Note 2 – Summary of Significant Accounting Policies.

Compensation expense related to employee stock option grants are recognized over the stock option's vesting period based on the fair value at the date the options are granted. The fair value of each option is estimated as of the date of grant using the Black-Scholes options-pricing model. In November 2010, the Company's Board of Directors approved the immediate vesting of all outstanding stock options under both the 1999 Plan and the 2009 Plan. Additionally, the Board authorized management to net-settle any outstanding stock options in cash. The option holder had a choice of receiving cash upon net settlement of options or to settle options for shares of the Company. Such modification of the stock options resulted in recognizing a liability equal to the portion of each award attributable to past service multiplied by the modified award's fair value, and was adjusted quarterly. The accelerated vesting and modification affected no other terms or conditions of the options, including the number of outstanding options or exercise price. As of June 30, 2012, the Company did not record such a liability as a result of the final options being net-settled for cash. During the fiscal year-ended June 30, 2012, 2011 and 2010, the Company recognized a total stock option expense of approximately $3,000, $1.3 million, and $0.6 million, respectively. The aggregate intrinsic values of the options exercised/forfeited during fiscal years 2012, 2011 and 2010 were approximately $0.5 million, $8.9 million, and $15.3 million, respectively.

Restricted Stock

The Company did not grant any shares of restricted stock for the fiscal years ended June 30, 2012, 2011 or 2010. For the year ended June 30, 2010, the Company recognized approximately $72,000 in compensation expense relating to restricted stock awards granted during the fiscal year ended June 30, 2009.

13. Related Party Transactions

Juneau Exploration LLC. In April 2012, the Company announced that Mr. Brad Juneau, the sole manager of the general partner of JEX, had joined the Company's board of directors and that the Company had entered into an advisory agreement with JEX (the "Advisory Agreement"), whereby in addition to generating and evaluating offshore and onshore exploration prospects for the Company, JEX will direct Contango's staff on operational matters including drilling, completions and production. Pursuant to the Advisory Agreement, JEX will be paid an annual fee of $2.0 million. In August 2012, the Board of Directors of the Company elected Mr. Juneau as President and Acting Chief Executive Officer of the Company.

In addition to generating and evaluating prospects for the Company via JEX, and directing the Company's operations through the Advisory Agreement and as President and Acting CEO of the Company, JEX and/or its affiliates (collectively, "JEX") have historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specify each participant's working interest ("WI"), net revenue interest ("NRI"), and describe when such interests are earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX, excluding Mr. Juneau, except where otherwise noted.

Republic Exploration LLC. In his capacity as sole manager of the general partner of JEX, Mr. Juneau also controls the activities of Republic Exploration LLC ("REX"), an entity owned 34.4% by JEX, 32.3% by Contango, and 33.3% by a third party which contributed other assets to REX. REX generates and evaluates offshore exploration prospects and has historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specify each participant’s working interest, net revenue interest, and describe when such interests are earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX. The

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Company proportionately consolidates the results of REX in its consolidated financial statements.

Contango Offshore Exploration LLC. Prior to its dissolution on June 1, 2010, in his capacity as sole manager of the general partner of JEX, Mr. Juneau controlled the activities of Contango Offshore Exploration LLC ("COE"), an entity then owned 65.63% by Contango and 34.37% by JEX. COE generated and evaluated offshore exploration prospects and had historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specified each participant's working interest, net revenue interest, and described when such interests were earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX. The Company proportionately consolidated the results of COE in its consolidated financial statements.

As of June 30, 2012, Contango, JEX, REX and JEX employees owned the following interests in the Company's offshore wells.

	Contango		JEX		REX		JEX Employees
	WI	NRI	WI	NRI	WI	NRI	ORRI
Dutch #1 - #5	47.05 %	38.12 %	1.61 %	1.29 %	— %	— %	2.02%
Mary Rose #1	53.21 %	40.45 %	2.01 %	1.51 %	— %	— %	2.79%
Mary Rose #2 - #3	53.21 %	38.67 %	2.01 %	1.44 %	— %	— %	2.79%
Mary Rose #4	34.58 %	25.49 %	1.31 %	0.95 %	— %	— %	1.82%
Mary Rose #5	37.80 %	27.88 %	1.43 %	1.04 %	— %	— %	1.54%
Ship Shoal 263	100.00 %	80.00 %	— %	— %	— %	— %	3.33%
Vermilion 170	83.20 %	64.83 %	4.30 %	3.35 %	12.50 %	9.74 %	3.33%

Below is a summary of transactions between the Company, JEX, REX and COE during the fiscal years ended June 30, 2012, 2011 and 2010:

- In October 2009 the Company spud the Ship Shoal 263 well which was owned 25% by Contango and 75% by COE. Under the terms of the applicable participation agreement, Contango had a 100% working interest through casing point. Once casing point was reached, COE exercised its option to back-in for a 15.19% working interest. Once production began, COE received a carried working interest of 6.75%, resulting in COE having a final working interest of 21.94% and Contango owning the remaining working interests. The Company paid JEX a prospect fee of $250,000 for generating this prospect.
- Upon dissolution on June 1, 2010, COE distributed its ownership interest in the following 3 wells to Contango and JEX in proportion to their ownership percentage in COE: i) Ship Shoal 263 - The Company and JEX kept their respective interests in Ship Shoal 263; ii) Grand Isle 70 - The Company and JEX sold their respective interests in Grand Isle 70 to an independent third-party in exchange for an ORRI. The Company subsequently sold its ORRI interests to JEX for approximately $0.1 million. iii) Grand Isle 72 - This well was plugged and abandoned in June 2010. Both the Company and JEX paid their respective portion to permanently abandon the site.
- In March 2010 the Company spud the Eloise South well. All owners paid for their proportionate share of drilling and completion costs based on their ownership percentage. The Company had a 23.8% working interest in this well and REX had a 9.6% working interest. Once production began, JEX employees received an ORRI of 1.33%.
- In June 2010 the Company spud its Rexer #1 well. Under the terms of the applicable participation agreement, the Company had a 100% working interest through payout of all costs. In May 2011, the Company sold Rexer #1 (See Note 5 - Discontinued Operations) prior to reaching payout. Once payout is reached with the new operator, JEX will have an option to back-in for a 10% working interest (7.25% net revenue interest). Other third-parties own the remaining working interests. JEX employees maintained a 2.5% ORRI in this well. The Company paid JEX a prospect fee of $250,000 for generating this prospect.
- In October 2010, the Company purchased JEX's 7.5% working interest in Ship Shoal 263 for $7.5 million, based on a reserve valuation as of the purchase date.

- Prior to its dissolution, COE owed the Company $5.9 million in principal and interest under a promissory note (the "COE Note") payable on demand. In connection with the dissolution, the Company assumed its 65.63% share of the obligation under the COE Note, while JEX assumed the remaining 34.37%, or approximately $2 million. This $2 million was paid to the Company in October 2010.

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- In February 2011 the Company spud Vermilion 170 which was owned 100% by the Company. Under the terms of the applicable participation agreement, Contango had a 100% working interest through casing point. Once casing point was reached, JEX and REX each exercised their option to back-in for a 2.6% and 7.5% working interest, respectively. Once production began, JEX and REX each received their carried working interest of 1.7% and 5.0%, respectively, resulting in JEX having a final working interest of 4.3% and REX having a final working interest of 12.5%. The Company owns the remaining working interests in this well. The Company paid JEX a prospect fee of $250,000 for generating this prospect.

- In May 2011 the Company spud its Rexer-Tusa #2 well. Under the terms of the applicable participation agreement, the Company had a 25% working interest through payout of all costs. In October 2011, the Company completed selling Rexer-Tusa #2 (See Note 5 - Discontinued Operations) prior to reaching payout. Once payout is reached with the new operator, JEX will have an option to back-in for a 10% working interest (7.36% net revenue interest). Other third-parties own the remaining working interests. JEX employees maintained a 2.92% ORRI in this well.

- In July 2011, the Company recompleted its Eloise South well uphole in the Cib-Op sands as our Dutch #5 well. Under the terms of the applicable joint operating agreement, all Dutch #5 well owners were required to purchase the Eloise South well bore from the Eloise South owners (the "Dutch Well Cost Adjustment"). All Eloise South and Dutch #5 well owners paid and/or received their proportionate share of the Dutch Well Cost Adjustment based on their ownership percentage in each well. JEX had a 1.6% working interest in Dutch #5; REX had a 9.6% working interest in Eloise South; and Contango had a 47.05% working interest in Dutch #5 and a 23.8% working interest in Eloise South.

- In December 2011, the Company purchased an additional working interest in Mary Rose #5 (see below) from an existing partner. The Company then sold to JEX its proportionate share of the existing partner's interest, based on JEX's ownership percentage in the well.

- In January 2012, the Company recompleted its Eloise North well uphole in the Cib-Op sands as our Mary Rose #5 well. Under the terms of the applicable joint operating agreement, all Mary Rose #5 well owners were required to purchase the Eloise North well bore from the Eloise North owners. (the "Mary Rose Well Cost Adjustment"). All Eloise North and Mary Rose #5 well owners paid and/or received their proportionate share of the Mary Rose Well Cost Adjustment based on their ownership percentage in each well. JEX had a 1.4% working interest in Mary Rose #5 and a 0.1% working interest in Eloise North; REX had a 13.2% working interest in Eloise North; and the Company had a 37.8% working interest in Mary Rose #5 and a 35.8% working interest in Eloise North.

- In March 2012, the Company was awarded Brazos Area 543 by the BOEM, which was bid on at the Western Gulf of Mexico Lease Sale No. 218 held on December 14, 2011. Under the terms of the applicable participation agreement, if the lease becomes a prospect, Contango will have a 100% working interest through casing point. Once casing point is reached, JEX may exercise its option to back-in for a 5% working interest. Once production begins (if successful), JEX shall receive its carried working interest of 3.33%, resulting in JEX having a final working interest of 8.33% (6.49% net revenue interest) Contango shall have a 75% working interest (58.44% net revenue interest),with third parties owning the remaining working interests. JEX employees will have a 2.33% working interest in this well. If the lease is developed into a prospect, the Company will pay JEX a prospect fee of $250,000 for generating this prospect.

In July 2012 the Company spud the Ship Shoal 134 prospect which is owned 100% by the Company. Under the terms of the applicable participation agreement, the Company has a 100% working interest through production. At first production (if successful), REX will receive a carried working interest of 10%. Once payout of post casing point costs has been reached, REX will have an option to back-in for an additional 12.5% working interest, resulting in REX having a final working interest of 22.50% (17.5% net revenue interest) with Contango owning the remaining working interests. JEX employees will receive an ORRI of 3.33% in this well. The Company paid JEX a prospect fee of $250,000 for generating this prospect.

- In July 2012 the Company spud the South Timbalier 75 prospect which was farmed-in 100% by the Company and REX. Under the terms of the applicable participation agreement, the Company has a 100% working interest through first production. At first production (if successful), REX will receive a carried working interest of 10%. Once payout of post casing point costs has been reached, REX will have an option to back-in for an additional 8.3% working interest, resulting in REX having a final working interest of 18.3% (13.1% net revenue interest) and the Company owning the remaining working interests. JEX employees will receive an ORRI of 3.33% in this well. The Company

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paid JEX a prospect fee of $250,000 for generating this prospect.

- For the five lease blocks where the Company was the Apparent High Bidder ("AHB") in the June 20, 2012 lease sale where the prospects were generated by REX, the Company has a 100% working interest through first production. At first production (if successful), REX will receive a carried working interest of 10%. Once payout of post casing point costs has been reached, REX will have an option to back-in for up to 12.5% working interest, resulting in REX having a final working interest of up to 22.5% (17.5% net revenue interest) and the Company owning the remaining working interests. JEX employees will receive an ORRI of 3.33% in these prospects.

- For the lease block where the Company was the AHB in the June 20, 2012 lease sale where the prospects were generated by JEX, the Company will carry JEX for 10% through first production and JEX employees will receive an ORRI of 3.33%.

- In the Tuscaloosa Marine Shale ("TMS"), a shale play in central Louisiana and Mississippi, the Company has a 100% working interest through first production. At first production of the existing acreage (if successful), JEX will receive a carried working interest of 10% and JEX employees will receive an ORRI of 2%, of which Mr. Juneau receives 0.75%, due to fees to third parties paid by JEX in order to get into the prospect, that were not billed to Contango. An additional 2% was granted to the geologist who is responsible for the generation of the TMS prospect. The geologist has subsequently been employed by JEX.

- In Jim Hogg County, Texas, on promoted wells, JEX has a 10% carry of the Company's working interest (for example, if the Company has a 50% working interest, JEX will have a 5% carried working interest), after the Company has acheived payout of its investment. On unpromoted wells, JEX has a 10% carried working interest of the Company's working interest. JEX employees will receive an ORRI of 1.25%

Below is a summary of payments received from (paid to) JEX, REX and COE in the ordinary course of business in our capacity as operator of the wells and platforms for the periods indicated. The Company made and received similar types of payments with other well owners (in thousands):

	2012		2011			2010		
	JEX	REX	JEX	REX	COE	JEX	REX	COE
Revenue payments as well owners	$(5,719)	$(3,166)	$(6,089)	$(1,908)	$—	$(5,026)	$(1,633)	$—
Joint interest billing receipts	928	2,422	1,437	2,068	81	837	629	469
Dutch well cost adjustment	—	—	161	(957)	—	—	—	—
Mary Rose well cost adjustment	118	(1,185)	—	—	—	—	—	—

Below is a summary of payments received from (paid to) JEX and REX as a result of specific transactions between the Company, JEX and REX. While these payments are in the ordinary course of business, the Company did not have similar transactions with other well owners (in thousands):

	2012		2011			2010	
	JEX	REX	JEX	REX	COE	JEX	REX
Sale of Grand Isle 70 ORRI	$—	$—	$—	$—	—	$104	$—
Sale of purchased interest in Mary Rose #5	8	—	—	—	—	—	—
Reimbursement of certain costs	(325)	(17)	(206)	(302)	(134)	(1,151)	—
Prospect fees	(250)	—	—	—	—	(1,750)	—
	(530)	—	—	—	—	—	—

Under advisory agreement dated April 1, 2012							
Purchase of Ship Shoal 263	—	—	(7,512)	—	—	—	—
REX distribution to members	—	823	—	—	—	—	—
Repayment of COE Note	—	—	2,028	—	—	—	—
Purchase of 50% interest in Alaska properties	—	—	—	—	—	(1,000)	—
Exploration costs in Alaska	—	—	(906)	—	—	(518)	—

As of June 30, 2012 and 2011, the Company's consolidated balance sheets reflected the following balances (in thousands):

	2012		2011	
	JEX	REX	JEX	REX
Accounts receivable:				
Trade receivable	$20	$18	$75	$117
Joint interest billing	158	92	164	937
Royalties and revenue payable	(813)	(682)	(997)	—

Contango ORE, Inc. Contango Mining Company (“Contango Mining”), a wholly owned subsidiary of the Company, was formed in October 2009 for the purpose of engaging in exploration in the state of Alaska for (i) gold ore and associated minerals and (ii) rare earth elements. Contango Mining initially acquired a 50% interest in these properties in Alaska from JEX in exchange for $1 million and a 1% ORRI in the properties under a Joint Exploration Agreement (the “Joint Exploration Agreement”). We believe JEX expended approximately $1 million on exploratory activities and related work on the properties prior to selling the initial 50% interest to Contango Mining. Contango Mining also agreed to fund the next $2 million of exploration costs. During the fiscal year ended June 30, 2011 and 2010, Contango Mining paid JEX approximately $0.9 million and $0.5 million, respectively, for exploration costs incurred by JEX in the state of Alaska.

In September 2010, Contango Mining acquired the remaining 50% interest in the properties by increasing the ORRI in the properties granted to JEX to 3% pursuant to an Amended and Restated Conveyance of Overriding Royalty Interest (the “Amended ORRI Agreement”). Contango Mining assumed control of the exploration activities and JEX and Contango Mining terminated the Joint Exploration Agreement.
Contango ORE, Inc. ("CORE") was formed on September 1, 2010 as a wholly-owned subsidiary of the Company and in November 2010, Contango Mining assigned the properties and certain other assets and liabilities to Contango. Contango contributed the properties and $3.5 million of cash to CORE, pursuant to the terms of a Contribution Agreement (the “Contribution Agreement”), in exchange for approximately 1.6 million shares of CORE's common stock. The transactions took place between companies under common control. Contango distributed all of CORE's common stock to Contango’s stockholders of record as of October 15, 2010, promptly after the effective date of CORE's Registration Statement Form 10 on the basis of one share of common stock for each ten (10) shares of Contango’s common stock then outstanding.

In November 2011, the Company executed a $1.0 million Revolving Line of Credit Promissory Note to lend money to CORE (the “CORE Note”). The Company and CORE share executive officers. The CORE Note contains covenants limiting CORE’s ability to enter into additional indebtedness and prohibiting liens on any of its assets or properties. Borrowings under the CORE Note bear interest at 10% per annum. Principal and interest are due from CORE to the Company on December 31, 2012, and may be prepaid at any time with no prepayment penalty.

On March 30, 2012 the Company received repayment of the $500,000 it had advanced under the CORE Note, plus accrued interest of approximately $15,000. As of June 30, 2012, there are no amounts outstanding under the CORE Note. CORE may re-borrow any portion of the $1.0 million through December 31, 2012.

Equity Compensation. In February 2012, the Company net-settled 45,000 stock options from two employees for a total of approximately $465,000. During the fiscal year ended June 30, 2011, the Company purchased 172,544 shares of its common stock for a total of approximately $9.8 million. Of this amount, 149,573 shares were purchased from four employees and one member of its board of directors for a total of approximately $8.7 million. During the fiscal year ended June 30, 2010, the Company purchased 115,454 shares of its common stock from three officers of the Company and two members of its board of directors for approximately $6.4 million. All the purchases were approved by the Company's board of directors and were completed at the closing price of the Company's common stock on the date of purchase.

14. Share Repurchase Programs

$100 Million Share Repurchase Program

In September 2008, the Company's board of directors approved a $100 million share repurchase program. All shares are purchased in the open market from time to time by the Company or through privately negotiated transactions. The purchases will be made subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market. Repurchased shares of common stock become authorized but unissued shares, and may be issued in the future for general corporate and other purposes. During the fiscal year ended June 30, 2012, we purchased 271,837 shares of our common stock at an average cost per share of $55.38 per share, for a total of approximately $15.1 million. The $100 million share repurchase program concluded in October 2011 with the Company having purchased 2,157,278 shares of its common stock at an average cost per share of $46.35 per share, for a total of approximately $100 million under the $100 million share repurchase program.

$50 Million Share Repurchase Program

On September 28, 2011, the Company's Board of Directors approved the adoption of a $50 million share repurchase program, effective upon completion of purchases under the Company's $100 million share repurchase program. The purchases made under the $50 million share repurchase program will be subject to the same terms and conditions as purchases made under the $100 million share repurchase program. During the fiscal year ended June 30, 2012, the Company purchased 100,381 shares at an average price of $53.45 per share, for a total of approximately $5.4 million under the $50 million share repurchase program. Additionally, in February 2012 the Company net-settled 45,000 options from two employees for a total of approximately $465,000. In total, under both share repurchase programs combined, the Company has purchased approximately 2.3 million shares of its common stock at an average cost per share of $46.67 and 45,000 stock options, for a total of approximately $105.8 million as of June 30, 2012, bringing its total share count to 15,292,448 shares of common stock outstanding and no options outstanding.

15. Subsequent Events

As of June 30, 2012, we had invested approximately $11.6 million in Alta Energy to purchase over 60,000 acres in the Kaybob Duvernay, a liquids rich shale play in Alberta, Canada. In August 2012, the Company invested an additional $0.7 million, bringing the Company's total investment in Alta Energy to approximately $12.3 million. Contango has a 2% interest in Alta Energy and a 5% interest in the Kaybob Duvernay project.

As of June 30, 2012, the Company had invested approximately $5.0 million to lease approximately 13,800 acres in the TMS. During July and August 2012, the Company leased an additional approximately 11,200 acres for approximately $3.7 million, bringing the Company's total investment in the TMS to 25,000 acres for approximately $8.7 million.

As of June 30, 2012, the Company had paid approximately $0.7 million into an exploration program involving acreage in Jim Hogg County, Texas with a large south Texas mineral owner. In August 2012, the Company paid an additional $0.5 million into this exploration program, bringing the total expenditure to approximately $1.2 million.

As of June 30, 2012, the Company owed approximately $8.8 million in remaining leasehold costs and rental payments for the six lease blocks bid on at the Central Gulf of Mexico Lease Sale 216/222. In August 2012, the Company was notified that it had been awarded East Cameron 124, Eugene Island 31, Ship Shoal 83 and South Timbalier 110 effective September 1, 2012. In August 2012, the Company paid approximately $1.2 million for East Cameron 124. As of the date of this report, the Company owed approximately $7.6 million for the remaining five lease blocks.

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SUPPLEMENTAL OIL AND GAS DISCLOSURES (Unaudited)

In accordance with U.S. GAAP for disclosures regarding oil and gas producing activities, and SEC rules for oil and gas reporting disclosures, we are making the following disclosures regarding our natural gas and oil reserves and exploration and production activities.

Costs Incurred. The following table presents information regarding our net costs incurred in the purchase of proved and unproved properties and in exploration and development activities for the periods indicated:

	Year Ended June 30,		
	2012	2011	2010
Property acquisition costs:		(thousands)	
Unproved	$5,404	$2,802	$11,319
Proved	381	10,135	2,009
Exploration costs	1,154	14,016	52,805
Development costs	10,350	39,211	40,902
Total costs incurred	$17,289	$66,164	$107,035

Natural Gas and Oil Reserves. Proved reserves are the estimated quantities of natural gas, oil and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and current regulatory practices. Proved developed reserves are proved reserves which are expected to be produced from existing completion intervals with existing equipment and operating methods.

Proved natural gas and oil reserve quantities at June 30, 2012, 2011, 2010 and 2009, and the related discounted future net cash flows before income taxes are based on estimates prepared by William M. Cobb & Associates, Inc. Such estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission.

The below table summarizes the Company's net ownership interests in estimated quantities of proved natural gas, oil and natural gas liquids ("NGLs") reserves and changes in net proved reserves as of June 30, 2012, 2011, 2010 and 2009, all of which are located in the continental United States. There were no material reserves associated with our equity investments.

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	Oil and Condensate (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)
Proved Developed and Undeveloped Reserves as of:			
June 30, 2009	5,004	7,401	280,616
Sale of minerals in place	—	—	—
Extensions and discoveries	1,276	1,081	40,635
Purchases of minerals in place	—	—	—
Revisions of previous estimates	(1,177)	(1,146)	(53,855)
Production	(505)	(598)	(21,385)
June 30, 2010	4,598	6,738	246,011
Sale of minerals in place	(126)	(648)	(16,804)
Extensions and discoveries	565	191	31,585
Purchases of minerals in place	53	9	929
Revisions of previous estimates	73	(302)	2,584
Production	(685)	(702)	(26,160)
June 30, 2011	4,478	5,286	238,145
Sale of minerals in place	—	—	—
Extensions and discoveries	—	—	—
Purchases of minerals in place	—	—	—
Revisions of previous estimates	(551)	1,262	(13,149)
Production	(615)	(662)	(23,617)
June 30, 2012	3,312	5,886	201,379
Proved Developed Reserves as of:			
June 30, 2009	5,004	7,401	280,616
June 30, 2010	4,328	6,167	231,260
June 30, 2011	3,738	5,037	205,085
June 30, 2012	3,353	5,664	196,268
Proved Undeveloped Reserves as of:			
June 30, 2009	—	—	—
June 30, 2010	270	571	14,751
June 30, 2011	740	249	33,060
June 30, 2012	(41)	222	5,111

The most significant change to our reserves during the fiscal year ended June 30, 2012 was due to current year production. During the fiscal year ended June 30, 2011, the most significant changes were associated with our discovery at Vermilion 170 and the sale of our Joint Venture Asset reserves (see Note 5 – Discontinued Operations). During the fiscal year ended June 30, 2010, we had a revision of approximately 48.5 Bcfe related to our Dutch and Mary Rose field reserves. As a result of newly learned bottom hole pressure data determined during a recent field wide shut-in and a “P/Z pressure test”, our independent third-party engineer concluded that we had less reserves than originally estimated.

Standardized Measure. The standardized measure of discounted future net cash flows relating to the Company’s ownership interests in proved natural gas and oil reserves as of June 30, 2012, 2011 and 2010 are shown below:

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CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS DISCLOSURES (Unaudited)

	As of June 30,		
	2012	2011	2010
		(thousands)	
Future cash inflows	$1,378,910	$1,801,236	$1,720,888
Future production costs	(301,137)	(313,688)	(232,641)
Future development costs	(31,214)	(52,053)	(66,237)
Future income tax expenses	(312,211)	(406,306)	(399,755)
Future net cash flows	734,348	1,029,189	1,022,255
10% annual discount for estimated timing of cash flows	(220,416)	(312,054)	(310,161)
Standardized measure of discounted future net cash flows	$513,932	$717,135	$712,094

Future cash inflows represent expected revenues from production and are computed by applying certain prices of natural gas and oil to estimated quantities of proved natural gas and oil reserves. As of June 30, 2012, future cash inflows were based on the first-day-of-the-month prices for the previous 12 months of $3.13 per MMBtu of natural gas, $96.07 per barrel of oil, and $59.39 per barrel of natural gas liquids. For the fiscal year ended June 30, 2011, future cash inflows were based on the first-day-of-the-month prices for the previous 12 months of $4.25 per MMBtu of natural gas, $90.27 per barrel of oil, and $55.78 per barrel of natural gas liquids. For the fiscal year ended June 30, 2010, future cash inflows were based on the first-day-of-the-month prices for the previous 12 months of $4.09 per MMBtu of natural gas, $76.21 per barrel of oil, and $44.62 per barrel of natural gas liquids, in each case before adjusting for basis, transportation costs and BTU content.

Future production and development costs are estimated expenditures to be incurred in developing and producing the Company’s proved natural gas and oil reserves based on historical costs and assuming continuation of existing economic conditions. Future development costs relate to compression charges at our platforms, abandonment costs, recompletion costs, and additional development costs for new facilities.

Future income taxes are based on year-end statutory rates, adjusted for tax basis and applicable tax credits. A discount factor of 10 percent was used to reflect the timing of future net cash flows. The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair value of the Company’s natural gas and oil properties. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates of natural gas and oil producing operations.

Change in Standardized Measure. Changes in the standardized measure of future net cash flows relating to proved natural gas and oil reserves are summarized below:

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SUPPLEMENTAL OIL AND GAS DISCLOSURES (Unaudited)

	Year Ended June 30,		
	2012	2011	2010
Changes in standardized measure due to current year operation:		(thousands)	
Sales of natural gas and oil produced during the period, net of production expenses	$(160,111)	$(188,810)	$(143,641)
Extensions and discoveries	—	160,712	151,760
Net change in prices and production costs	(144,533)	5,401	108,883
Changes in estimated future development costs	17,322	41,989	7,969
Revisions in quantity estimates	(25,486)	4,078	(190,840)
Purchase of reserves	—	6,556	—
Sale of reserves	—	(20,031)	—
Accretion of discount	98,104	97,044	88,986
Changes in income taxes	47,616	(5,558)	(6,574)
Change in the timing of production rates and other	(36,115)	(96,340)	57,460
Net change	(203,203)	5,041	74,003
Beginning of year	717,135	712,094	638,091
End of year	$513,932	$717,135	$712,094

For the fiscal year ended June 30, 2012, the standardized measure decreased by approximately $203.2 million, principally due to a decrease in natural gas and oil prices and current year production. For the fiscal year ended June 30, 2011, the standardized measure increased by approximately $5.0 million which was due to our discovery at Vermilion 170, offset by current year production and sales of our Joint Venture Asset reserves (see Note 5 – Discontinued Operations).

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QUARTERLY RESULTS OF OPERATIONS (Unaudited)

Quarterly Results of Operations. The following table sets forth the results of operations by quarter for the years ended June 30, 2012 and 2011:

	Quarter Ended			
	Sept. 30,	Dec. 31,	Mar. 31,	June 30,
	(thousands, except per share amounts)			
Fiscal Year 2012:				
Revenues from continuing operations	$44,203	$53,907	$41,339	$39,823
Income from continuing operations (1)	$15,586	$19,589	$14,699	$9,339
Net income (loss) from discontinued operations, net of taxes	$(682)	$(114)	$(26)	$(2)
Net income attributable to common stock	$14,904	$19,475	$14,673	$9,337
Net income per share (2):				
Basic:	$0.95	$1.27	$0.96	$0.61
Diluted:.	$0.95	$1.27	$0.96	$0.61
Fiscal Year 2011:				
Revenues from continuing operations	$53,097	$49,123	$52,641	$48,917
Income from continuing operations (1)	$31,334	$15,070	$25,282	$26,563
Net income (loss) from discontinued operations, net of taxes	$(877)	$2,279	$465	$(286)
Net income attributable to common stock	$18,941	$11,767	$16,796	$17,529
Net income per share (2):				
Basic:	$1.21	$0.75	$1.07	$1.12
Diluted:	$1.20	$0.75	$1.07	$1.12

(1) Represents natural gas and oil sales, less operating expenses, exploration expenses, depreciation, depletion and amortization, lease expirations and relinquishments, impairment of natural gas and oil properties, general and administrative expense, and other income and expense before income taxes.

(2) The sum of the individual quarterly earnings per share may not agree with year-to-date earnings per share as each quarterly computation is based on the income for that quarter and the weighted average number of common shares outstanding during that quarter.