CONTANGO OIL & GAS CO
Form 10-K
September 13, 2007
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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, 2007

¨ **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	American Stock Exchange

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 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, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one). Large accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨

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, 2006, 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 American Stock Exchange) was $280,884,573. As of August 31, 2007, there were 16,015,138 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, 2007

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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 expressions 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
- Development, construction and financing of our liquefied natural gas (LNG) receiving terminal
- Investments in alternative energy

Although we believe the expectations reflected in such forward-looking statements are reasonable, we cannot assure you that such expectations will 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 wells in the Gulf of Mexico
- 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 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
- Uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures

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- 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
- 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
- Ability of LNG to become a competitive energy supply in the United States
- Ability to fund our LNG project, cost overruns and third party performance
- Successful commercialization of alternative energy technologies
- Drilling and operating costs, production rates and ultimate reserve recoveries in our Arkansas Fayetteville Shale play
- Drilling and operating costs, production rates and ultimate reserve recoveries in our Eugene Island 10 (Dutch) and State of Louisiana (Mary Rose) acreage.
- The ability of Republic Exploration, LLC (REX), our partially-owned subsidiary, to fund its working interest commitment in our Dutch and Mary Rose development.

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 16 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.

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 primarily offshore in the Gulf of Mexico and in the Arkansas Fayetteville Shale. Contango Operators, Inc. (COI), our wholly-owned subsidiary, acts as operator on certain offshore prospects. The Company also owns a 10% interest in a limited partnership formed to develop an LNG receiving terminal in Freeport, Texas, and holds investments in companies focused on commercializing environmentally preferred energy technologies.

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 our alliance partners. We depend totally upon our alliance partners for prospect generation expertise. Our alliance partners, Juneau Exploration, L.P. (JEX) and Alta Resources, LLC (Alta) are experienced and have successful track records in exploration.

Using our limited capital availability to increase our reward/risk potential on selective prospects. We have concentrated our risk investment capital in two prospect areas; our onshore Arkansas Fayetteville Shale play and our offshore Gulf of Mexico prospects. Exploration prospects are inherently risky as they require large amounts of capital with no guarantee of success. COI drills and operates our offshore 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.

Operating in the Gulf of Mexico. COI was formed for the purpose of drilling and operating exploration wells in the Gulf of Mexico. Assuming the role of an operator represents a significant increase in the risk profile of the Company since the Company has limited operating experience. While COI has historically drilled turnkey wells, adverse weather conditions as well as difficulties encountered while drilling our offshore wells could cause our contracts to come off turnkey and thus lead to significantly higher drilling costs.

Arkansas Fayetteville Shale. We have made a major commitment to our Arkansas Fayetteville Shale program and this commitment is expected to continue to grow as we participate in the drilling of hundreds of gross exploration/development wells over the next five to ten years.

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 exploration, LNG and alternative energy investment activities. Since its inception, the Company has sold over $87.0 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. With respect to our onshore prospects, we plan to continue outsourcing our geological, geophysical, and reservoir engineering and land functions, and partnering with cost efficient operators. We have six employees.

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Structuring transactions to share risk. Our alliance partners share in the upfront costs and the risk of our exploration prospects.

Structuring incentives to drive behavior. We believe that equity ownership aligns the interests of our partners, employees, and stockholders. Our directors and executive officers beneficially own or have voting control over approximately 24% of our common stock.

Exploration Alliances with JEX and Alta

Alliance with JEX. JEX is a private company formed for the purpose of assembling domestic natural gas and oil prospects. Under our agreement with JEX, JEX generates natural gas and oil prospects and evaluates exploration prospects generated by others. JEX focuses on the Gulf of Mexico, and generates offshore exploration prospects via our affiliated companies, Republic Exploration, LLC (REX), Contango Offshore Exploration, LLC (COE) and Magnolia Offshore Exploration LLC (MOE) (see Offshore Gulf of Mexico Exploration Joint Ventures below).

Alliance with Alta. Alta is a private company formed for the purpose of assembling domestic, onshore natural gas and oil prospects. Our arrangement with Alta generally provides for us to pay our share of seismic and lease costs, with Alta generally receiving a negotiated overriding royalty interest (ORRI) and a carried or back-in working interest.

Onshore Exploration and Properties

Alta Activities

Arkansas Fayetteville Shale

In March 2005, Contango, Alta and another private company entered into an agreement to acquire natural gas, oil, and mineral leases in the Arkansas Fayetteville Shale play area located in Pope, Van Buren, Conway, Faulkner, Cleburne, and White Counties, Arkansas. As of August 31, 2007, we and our partners have acquired or received commitments on approximately 45,300 net mineral acres at a cost of approximately $13.6 million. Contango has a 70% working interest prior to payout. At project payout, Alta will be assigned a 20% reversionary working interest, proportionately reduced to Contango, Alta and the other participant. Alta will receive an ORRI in each lease assignment contingent on the amount of lease burden assigned to the third party royalty owners. Our 70% share of the lease acquisition costs as of August 31, 2007, is approximately $9.5 million.

The Arkansas Oil & Gas Commission has now approved 16 separate 640-acre drilling units in Arkansas that we estimate will allow our partnership to drill and operate approximately 144 horizontal wells. The horizontal wells are estimated to cost between $3.5 to $2.5 million each. Thus far, our working interest and net revenue interest in these Alta operated wells has averaged approximately 46% and 36%, respectively. Alta intends to continue to seek approval from the Arkansas Oil & Gas Commission for additional 640-acre drilling units.

The first wells drilled by Tepee Petroleum as contract operator took considerably longer than expected to drill and incurred significant cost overruns. Of these wells, the Alta-Thines #1-30H is currently producing at 0.5 million cubic feet per day (Mmcf/d), the Alta-Ledbetter #1-33H is currently producing at 0.7 Mmcf/d, the Alta-Briggler #1-31H is shut in awaiting pipeline hookup, the Alta-Clark #1-26H is currently producing at 0.7 Mmcf/d and the Alta-Wooten #1-34H is currently producing at 1.0 Mmcf/d. The 8/8ths cost for drilling and completing these five wells is estimated at $20.4 million (approximately $10.6 million net to Contango). We have already invested the $10.6 million as of August 31, 2007 and do not expect to incur any significant additional costs for these five wells. Additionally, two wells, the Alta-Beck #1-32H and the Alta-Kaufman #1-12H have been plugged and abandoned due to mechanical problems at a cost of approximately $4.1 million, net to the Company. This charge was recorded in the fourth quarter of the fiscal year ended June 30, 2007.

Alta Operating Company drilled the next four wells which were all successful. The first of these, the Alta-Huff #1-29H, was spud in March 2007 and is currently producing at 1.6 Mmcf/d. The second well, the Alta- Jones #1-29H, was spud in April 2007 and is currently producing at 3.5 Mmcf/d. The third and fourth wells, the

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Alta-Chwalinski #2-29H and Alta-Chwalinski #3-29, were spud in May 2007, simultaneously fraced, and are currently producing at a combined 3.6 million cubic feet equivalent per day (Mmcfe/d). These four wells are in and around the Gravel Hill Field area in Van Buren County, Arkansas. In addition, Alta arranged for an independent third party operator to drill two additional wells on Alta s behalf. The first of these, the Alta-Chwalinski #1-29H, was spud in March 2007 and is currently producing at 1.3 Mmcf/d. The second, the Alta-Koone #1-4H, was spud in March 2007 and is currently producing at 0.4 Mmcf/d. In June 2007, Alta spud the Deltic #1-8H and in August 2007, Alta spud the Alta-Deltic #2-8H which is currently drilling horizontally. We expect to simultaneously frac these two Deltic wells in September 2007. The 8/8ths cost for drilling and completing these eight wells is estimated to be $20.7 million (approximately $10.2 million net to Contango). Of this $10.2 million, we have already expended approximately $8.9 million as of August 31, 2007. Contango s net average working interest and net revenue interest in the 13 above Alta-operated wells, prior to project payout, are approximately 50% and 40%, respectively. As of August 31, 2007, these Alta-operated wells were producing at a combined rate of 5.2 Mmcf/d, net to Contango.

In addition, we have been integrated by a third party independent oil and gas exploration company into 129 wells as of July 31, 2007 (the Integrated Wells). Of these 129 Integrated Wells, 78 are producing. The 8/8ths production rate for 68 of these 78 producing wells was 58 Mmcf/d as of July 31, 2007 (approximately 3.0 Mmcf/d, net to Contango). Production data for the remaining ten producing wells was not available. The remaining 51 Integrated Wells are either currently being drilled or are expected to be drilled over the next several months. The 8/8ths cost for drilling and completing these 129 wells is estimated to be $307.0 million (approximately $17.0 million net to Contango). Of this $17.0 million, we have already invested approximately $12.1 million as of June 30, 2007. Contango s net average working interest and net revenue interest in these 129 wells are approximately 6% and 5%, respectively.

Texas, Alabama and Louisiana

Outside of Arkansas, we spudded two onshore wells with Alta in fiscal year 2007 and one in fiscal year 2008. The Alta-Ellis #1 in Texas, in which we have a 50% working interest, is currently producing at 0.4 Mmcf/d. We recorded an impairment charge of $0.2 million for this well in December 2006. The Temple Inland #1 in Louisiana, in which we have a 77% working interest, is currently producing at 1.0 Mmcf/d and 30 barrels of oil per day. The Alta-Coley in Alabama, in which we have a 67.5% working interest, was spud in July 2007 and was determined to be a dry hole at a cost of approximately $0.5 million. This charge was recorded in the fourth quarter of the fiscal year ended June 30, 2007.

We have also invested with Alta in the developing West Texas Barnett Shale play in Jeff Davis and Reeves Counties, Texas. Alta has leased approximately 5,800 net mineral acres (4,000 net mineral acres to Contango before a basket payout). A third party operator has drilled several wells near our acreage. Our plans are to monitor activity in this play.

Offshore Gulf of Mexico Exploration Joint Ventures

Contango directly and through affiliated companies conducts exploration activities in the Gulf of Mexico. As of June 30, 2007, Contango and its affiliates had interests in 70 offshore leases. See Offshore Properties below for additional information on our offshore properties.

As of June 30, 2007, Contango owned a 42.7% equity interest in REX, a 76.0% equity interest in COE, and a 50.0% equity interest in MOE, all of which were formed for the purpose of generating exploration opportunities in the Gulf of Mexico. See Exhibit 21.2 for an organizational chart of our subsidiaries. These companies have collectively licensed approximately 4,450 blocks of 3-D seismic data and have focused on identifying prospects, acquiring leases at federal and state lease sales and then selling the prospects to third parties, including Contango, subject to timed drilling obligations plus retained reversionary interests in favor of REX, COE and MOE.

Republic Exploration LLC. On August 22, 2007, REX was the apparent high bidder on two lease blocks at the Western Gulf of Mexico Lease Sale No. 204. REX bid approximately $1.75 million on High Island

263, and approximately $1.1 million on High Island A38. An apparent high bid (AHB) gives the bidding party priority in award of offered tracts, notwithstanding the fact that the Minerals Management Service (MMS) may reject all bids for a given tract. The MMS review process can take up to 90 days on some bids. Upon completion of that process, final results for all AHB s will be known.

In June 2007, REX was awarded State Lease No. 19396 at the State of Louisiana Mineral Lease Sale for an aggregate purchase price of approximately $0.3 million. State Lease No. 19396, together with our other State of Louisiana prospects, are commonly referred to as the Mary Rose prospect.

Record title interests in the Vermilion 73 and South Marsh Island 247 leases have been assigned to a common third party. Vermillion 73 was drilled and determined to be a dry hole. REX negotiated with the farmee and lowered its ORRI from 5% to 1.5% on Vermillion 73 in exchange for $35,000 so that another well may be drilled in the same block. The second well at Vermilion 73 was drilled during the second quarter of 2007 and also determined to by dry. South Marsh Island 247 was drilled and determined to be a dry hole. The well was plugged and abandoned on September 3, 2007. REX had reserved a 5.0% ORRI before payout on South Marsh Island 247.

REX and COE have farmed out East Breaks 369/370 and Vermillion 154. East Breaks 369 was spud in March 2007 and determined to be a dry hole. The well has been plugged and abandoned. The farmee has until September 1, 2008 to decide if it will drill East Breaks 370. Vermillion 154 has been farmed out, and the operator expects to drill an exploratory well prior to July 2008.

In February 2007, REX was awarded State Lease 19261 and 19266 at the State of Louisiana Mineral Lease Sale for an aggregate purchase price of approximately $4.6 million ($1.8 million net to Contango).

In November 2006, REX acquired 75% of High Island A243 from a private company in exchange for REX paying all future delay rentals. In November 2006, COE acquired 75% of East Breaks 167, High Island A311, East Breaks 166 and High Island A342 from a private company in exchange for COE paying all future delay rentals.

In October 2006, REX was awarded the following three lease blocks from the Western Gulf of Mexico Lease Sale #200 for an aggregate purchase price of approximately $1.0 million: High Island A196, High Island A197 and High Island A198.

On September 2, 2005, Contango purchased an additional 9.4% ownership interest in REX for $5.625 million from JEX. As a result of this purchase, our equity ownership interest in REX increased from 33.3% to 42.7%. As of June 30, 2007, Contango had approximately $5.9 million invested in REX. The three other members of REX are JEX, its managing member, a privately held investment company, and a privately held seismic company. REX holds a non-exclusive license to approximately 2,637 blocks of 3-D seismic data in the shallow waters of the Gulf of Mexico. This data is used to identify, acquire and exploit natural gas and oil prospects. All leases owned by REX are subject to a 3.3% ORRI in favor of the JEX prospect generation team. See Offshore Properties below for more information on REX s offshore properties.

In April 2005, REX, along with COI, secured from a third party, the right to earn an assignment of operating rights in Eugene Island 10. In September 2005, REX, COI and other third parties entered into a participation agreement whereby COI was named the operator. See Contango Operators, Inc. below for additional information on Eugene Island 10.

Contango Offshore Exploration LLC. Grand Isle 72 (Liberty), a COE prospect, began producing in March 2007 and as of August 31, 2007 was producing at a rate of approximately 1.5 Mmcfe/d. COE has invested approximately $5.0 million ($3.8 million net to the Company) in drilling, completion, pipeline and production facility costs as of August 31, 2007. COE s net revenue interest in this well is 40%. As of June 30, 2007, COE had borrowed $4.3 million from the Company under a promissory note (the Note) to fund a portion of its share of development costs at Grand Isle 72. The Note bears interest at a per annum rate of 10% and is payable upon demand.

Grand Isle 70, a COE prospect, was spud in July 2006 and proved to be a discovery. The well has been temporarily abandoned while alternative development scenarios are being evaluated. COE has a 52.6% working interest and a 42.1% net revenue interest in this well.

On September 2, 2005, Contango purchased an additional 9.4% ownership interest in COE for $1.875 million from JEX. As a result of this purchase, our equity ownership interest in COE increased from 66.6% to 76.0%. As of June 30, 2007, Contango had approximately $19.4 million invested in COE, which COE has used to acquire and reprocess 1,815 blocks of 3-D seismic data and to acquire leases in the Gulf of Mexico. The two other members of COE are JEX, its managing member, and a privately held investment company. All leases are subject to a 3.3% ORRI in favor of the JEX prospect generation team. See Offshore Properties below for additional information on COE s offshore properties.

Magnolia Offshore Exploration LLC. As of June 30, 2007, Contango had approximately $1.0 million invested in MOE. JEX is the only other member of MOE and acts as the managing member, deciding which prospects MOE may acquire, develop, and exploit. MOE s license rights to 3-D seismic data have been assigned to COE. All leases are subject to a 3.3% ORRI in favor of the JEX prospect generation team. See Offshore Properties below for additional information on MOE s offshore properties.

The MMS has implemented a rule on royalty relief for shallow water, deep shelf natural gas production from certain Gulf of Mexico leases. Deep shelf gas refers to natural gas produced from depths greater than 15,000 feet in waters of 200 meters or less. Royalty relief is available on the first 15 billion cubic feet (Bcf) of natural gas production if produced from an interval between 15,000 to less than 18,000 feet. Royalty relief is available on the first 25 Bcf of natural gas production if produced from an interval between 18,000 to less than 20,000 feet. Royalty relief is available on the first 35 Bcf of natural gas production if produced from well depths at or greater than 20,000 feet. This royalty relief is expected to have a positive impact on the economics of deep gas wells drilled on the shelf of the Gulf of Mexico.

Non-Operated Offshore Wells. The Company has non-operating working interests in three offshore blocks: Ship Shoal 358, Eugene Island 113-B and West Delta 36. Contango s net revenue interest in these three wells is 5.8%, 3.1% and 3.67%, respectively. The Company depends on third-party operators for the operation and maintenance of these production platforms. As of August 31, 2007, Ship Shoal 358 and Eugene Island 113-B were not producing. Ship Shoal 358 is to be re-completed later this year and Eugene Island 113-B is to have compression installed. West Delta 36 was producing at a rate of approximately 11.5 Mmcfe/d. REX has a 3.67% ORRI before payout in West Delta 36, and at its option, may elect either a 5.0% ORRI or 25% working interest (WI) after payout. The Company had a non-operating working interest in Eugene Island 76, but this well depleted in November 2006.

Contango Operators, Inc.

COI is a wholly-owned subsidiary of Contango formed for the purpose of drilling exploration and development wells in the Gulf of Mexico. As part of our strategy, COI will operate and acquire significant working interests in offshore exploration and development opportunities in the Gulf of Mexico, usually under a farm-out agreement with either REX or COE. COI expects to take working interests in these prospects under the same arms-length terms offered to industry third party participants. COI also operates and acquires significant working interests in offshore exploration and development opportunities under farm-in agreements with third parties.

Current Activities. During July 2007, the Company began producing from its Dutch #2 well, successfully completed and production tested its Dutch # 3 well, and spudded its Mary Rose #1 well, located on State of Louisiana Lease No. 18640.

As of August 25, 2007, our Dutch #1 and #2 wells were flowing at a combined 8/8ths production rate of approximately 63.2 Mmcfe/d. COI has invested approximately $11.4 million to drill and complete Dutch #1 and #2, including pipeline and production facility costs. During June 2007, one of the farmors of the Eugene Island 10 block backed in for a 12.5% working interest. Therefore, COI now has a 16.04% WI and REX has a

56.88% WI in each of the Dutch wells. For sales of natural gas, the net revenue interests to COI and REX are approximately 14.7% and 52.1%, respectively, with MMS deep gas royalty relief on the first 15 Bcf of gas produced from the entire field. Once the royalty relief has expired for natural gas, and for all sales of oil and condensate, COI and REX have a net revenue interest of 12.07% and 42.79%, respectively. The lease was farmed in on a produce-to-earn basis. The lease has now been assigned, and REX has earned the lease.

The Company s Dutch #3 well was production tested in July 2007 at a rate of approximately 34 Mmcfe/d. As of August 31, 2007, the Company had invested approximately $3.7 million to drill and complete this well, including pipeline and production facility costs. We estimate an additional $5.6 million will be required to build production and pipeline facilities to commence production. The well will flow into the same platform currently being used by Dutch #1 and #2 and we expect the well will be on-stream by the end of September 2007. COI has a 16.04% WI and REX has a 56.88% WI in Dutch #3. For sales of natural gas, the net revenue interests to COI and REX are approximately 14.7% and 52.1%, respectively, with MMS deep gas royalty relief on the first 15 Bcf of gas produced from the entire field. Once the royalty relief has expired for natural gas, and for all sales of oil and condensate, COI and REX have a net revenue interest of 12.07% and 42.79%, respectively. Once the second farmor backs in after project payout, COI and REX s working interests will be reduced to 13.75% and 48.75%, respectively.

We are currently drilling our Mary Rose #1 prospect, located off the coast of Louisiana, which is operated by COI. Our capital expenditure budget calls for us to invest approximately $2.5 million in estimated dry hole costs in the drilling of Mary Rose #1. In the event we have exploration success, our capital budget will be significantly increased as we will incur additional costs to complete the well and pay for production and pipeline facilities. In the event of tropical storms or hurricanes in the Gulf of Mexico while Mary Rose #1 is drilling, our estimated dry hole costs could be significantly greater. As a result of Hurricane Dean, we had to discontinue drilling and went off turn-key operations and lost ten days of drilling time at an estimated 8/8ths cost of $1.4 million. COI has a 15.72% working interest and an 11.27% net revenue interest in this well. The prospect is being drilled under a turn-key drilling contract.

The Company s independent third party engineer estimates the Dutch (Eugene Island 10) and Mary Rose (offshore State of Louisiana) discoveries to have total proved reserves of 226 billion cubic feet equivalent (Bcfe) (65 Bcfe net to Contango). A production platform and pipeline, at an estimated 8/8ths cost of $56.0 million, with a capacity of 300 Mmcfe/d is being built by the Company to process and transport anticipated production from the Mary Rose #1 well and from an expected additional three to five wells. The Company expects it will take between seven to nine wells to fully develop its Dutch and Mary Rose discoveries. The platform and pipeline are expected to be delivered by the end of the year and scheduled to be placed into service in May 2008. If successful, the Mary Rose #1 and follow-on developmental wells are anticipated to begin production in May 2008.

In December 2006, COI sold its 25% working interest in Grand Isle 72 to an independent oil and gas company for $7.0 million. The sold property had reserves of approximately 1.9 billion cubic feet equivalent (Bcfe), net to COI. The Company recognized a loss of approximately $2.4 million for the fiscal year ended June 30, 2007 as a result of this sale. The Company continues to have an interest in Grand Isle 72 via its investment in COE. COE has a 50% working interest and a 40% net revenue interest in this well.

During July 2006, in the offshore Gulf of Mexico, we drilled two dry holes at West Delta 43 and High Island A-279.

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Offshore Properties

Producing Properties. The following table sets forth the interests owned by Contango and related entities in the Gulf of Mexico which are producing natural gas or oil as of August 31, 2007:

Area/Block	WI	NRI	Status
Contango Operators, Inc:			
Eugene Island 113B	0%	1.7%	Awaiting installation of compression
Eugene Island 10 #1	16.0%	14.7%	Producing
Eugene Island 10 #2	16.0%	14.7%	Producing
Contango Offshore Exploration LLC:			
Ship Shoal 358, A-3 well	10.0%	7.7%	Awaiting Re-completion
Grand Isle 72	50.0%	40.0%	Producing
Republic Exploration LLC:			
Eugene Island 113B	0%	3.3%	Awaiting installation of compression
West Delta 36	(1)	(1)	Producing
Eugene Island 10 #1	56.9%	52.1%	Producing
Eugene Island 10 #2	56.9%	52.1%	Producing

(1) REX has a 3.67% ORRI before payout and, at its option, may elect either a 5.0% ORRI or 25% WI after payout.

Farmed-Out Properties. The following table sets forth the working interests and net revenue interests owned by Contango and related entities in the Gulf of Mexico which have been farmed out as of August 31, 2007:

Area/Block	WI	NRI	Status
Republic Exploration LLC:			
Vermilion 154	(2)	(2)	Drilling expected by summer 2008
Vermillion 73	(3)	(3)	Determined to be a dry hole
South Marsh Island 247	(4)	(4)	Determined to be a dry hole
Contango Offshore Exploration LLC:			
East Breaks 369	-	-	Determined to be a dry hole
East Breaks 370	(5)	(5)	No drilling date has been determined yet
Vermilion 154	(2)	(2)	Drilling expected by summer 2008

(2) REX and COE will split a 25% back-in WI after payout.
(3) Record title interest in lease has been assigned to a third party.
(4) Record title interest in lease has been assigned to a third party. REX has reserved a 5% of 8/8ths ORRI before payout.
(5) Farmee has until September 1, 2008 to decide if East Breaks 370 will be drilled. COE will receive a 3.67% ORRI before project payout and a 6.67% ORRI after project payout.

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Leases. The following table sets forth the working interests owned by Contango and related entities in the Gulf of Mexico as of August 31, 2007:

Area/Block	WI	Lease Date
Contango Operators, Inc.:		
West Cameron 174	10.0%	Jul-03
Grand Isle 63	25.0%	May-04
Grand Isle 73	25.0%	May-04
West Delta 43	35.0%	May-04
S-L 18640 (LA)	15.7%	Jul-05
S-L 18860 (LA)	15.7%	Jan-06
Ship Shoal 14	37.5%	May-06
Ship Shoal 25	37.5%	May-06
South Marsh Island 57	37.5%	May-06
South Marsh Island 59	37.5%	May-06
South Marsh Island 75	37.5%	May-06
South Marsh Island 282	37.5%	May-06
Grand Isle 70	3.65%	Jun-06
West Delta 77	25.0%	Jun-06
Vermilion 194	37.5%	Jul-06
Eugene Island 10	16.0%	Nov-06
S-L 19261 (LA)	15.7%	Feb-07
S-L 19266 (LA)	15.7%	Feb-07
S-L 19396 (LA)	15.7%	Jun-07

Area/Block	WI	Lease Date
Republic Exploration LLC:		
West Cameron 174	90.0%	Jul-03
High Island 113	100.0%	Oct-03
South Timbalier 191	50.0%	May-04
Vermilion 36	100.0%	May-04
Vermilion 109	100.0%	May-04
Vermilion 134	100.0%	May-04
West Cameron 179	100.0%	May-04
West Cameron 185	100.0%	May-04
West Cameron 200	100.0%	May-04
West Delta 18	100.0%	May-04
West Delta 33	100.0%	May-04
West Delta 34	100.0%	May-04
West Delta 43	30.0%	May-04
Ship Shoal 220	50.0%	Jun-04
South Timbalier 240	50.0%	Jun-04
West Cameron 133	100.0%	Jun-04
West Cameron 80	100.0%	Jun-04
West Cameron 167	100.0%	Jun-04
Eugene Island 76	0%	Jul-04
Vermilion 130	100.0%	Jul-04
West Cameron 107	100.0%	May-05
Eugene Island 168	50.0%	Jun-05
S-L 18640 (LA)	55.7%	Jul-05
S-L 18860 (LA)	55.7%	Jan-06
High Island A243	75.0%	Jan-06
South Marsh Island 57	50.0%	May-06
South Marsh Island 59	50.0%	May-06
South Marsh Island 75	50.0%	May-06
South Marsh Island 282	50.0%	May-06

Ship Shoal 14	50.0%	May-06
Ship Shoal 25	50.0%	May-06
West Delta 77	50.0%	Jun-06
Vermilion 194	50.0%	Jul-06
High Island A196	100.0%	Oct-06
High Island A197	100.0%	Oct-06
High Island A198	100.0%	Oct-06
Eugene Island 10	56.9%	Nov-06
S-L 19261 (LA)	55.7%	Feb-07
S-L 19266 (LA)	55.7%	Feb-07
S-L 19396 (LA)	55.7%	Jun-07

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Area/Block	WI	Lease Date
Contango Offshore Exploration LLC:		
Ship Shoal 358	10%	Jun-98
Viosca Knoll 167	100.0%	May-03
Vermilion 231	100.0%	May-03
Viosca Knoll 161	33.3%	Jul-03
Eugene Island 209	100.0%	Jul-03
High Island A16	100.0%	Dec-03
East Breaks 283	100.0%	Dec-03
South Timbalier 191	50.0%	May-04
Grand Isle 63	50.0%	May-04
Grand Isle 72	50.0%	May-04
Grand Isle 73	50.0%	May-04
Ship Shoal 220	50.0%	Jun-04
South Timbalier 240	50.0%	Jun-04
Viosca Knoll 118	33.3%	Jun-04
Viosca Knoll 475	100.0%	May-05
Eugene Island 168	50.0%	Jun-05
East Breaks 366	100.0%	Nov-05
East Breaks 410	100.0%	Nov-05
East Breaks 167	75.0%	Dec-05
High Island A311	75.0%	Dec-05
East Breaks 166	75.0%	Jan-06
High Island A342	75.0%	Jan-06
Ship Shoal 263	75.0%	Jun-06
Grand Isle 70	52.6%	Jun-06
Viosca Knoll 119	50.0%	Jun-06
Viosca Knoll 383	100.0%	Jun-06

Area/Block	WI	Lease Date
Magnolia Offshore Exploration LLC:		
Viosca Knoll 161	16.7%	Jul-03
Viosca Knoll 118	16.7%	Jun-04

Freeport LNG Development, L.P.

As of June 30, 2007, the Company has invested $3.2 million and owns a 10% limited partnership interest in Freeport LNG Development, L.P. (Freeport LNG), a limited partnership formed to develop, construct and operate a 1.75 billion cubic feet per day (Bcf/d) liquefied natural gas (LNG) receiving terminal in Freeport, Texas. Startup is expected to occur in the first quarter of calendar year 2008.

In July 2004, Freeport LNG finalized its transaction with The ConocoPhillips Company (ConocoPhillips) for the financing, construction and use of the LNG receiving terminal in Freeport, Texas. ConocoPhillips executed a terminal use agreement, purchased a 50% interest in the general partner managing the Freeport LNG project and agreed to provide construction funding to the venture. This construction funding is non-recourse to Contango. The Dow Chemical Company (Dow Chemical) has also executed a terminal use agreement and, in an unrelated transaction with another limited partner, has purchased a 15% limited partnership interest in Freeport LNG. Freeport LNG is responsible for the commercial activities of the partnership, while the general partners, Michael Smith and ConocoPhillips, manage the entire project, with ConocoPhillips, under a construction advisory and management agreement, providing engineering expertise to help manage the construction of the facility. In January 2005 Freeport LNG executed a terminal use agreement with a subsidiary of the Mitsubishi Corporation.

In January 2005, Freeport LNG received its authorization to commence construction of the first phase of its terminal from the Federal Energy Regulatory Commission (the FERC) and construction of the 1.75 Bcf/d facility commenced on January 17, 2005. Phase I has been restructured to buy back some capacity from ConocoPhillips and add Mitsubishi to Phase I. As of June 30, 2007, the terminal s Phase I capacity has been sold to ConocoPhillips (0.9 Bcf/d), Dow Chemical (0.5 Bcf/d) and Mitsubishi Corporation (0.15 Bcf/d). Construction

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is expected to be completed by the first quarter of 2008. The engineering, procurement and construction contractor is a consortium of Technip USA, Zachry Construction of San Antonio, and Saipem SpA of Italy.

A majority of the Freeport LNG financing for Phase I is being provided by ConocoPhillips through a construction loan, with debt service being provided by the terminal use agreement with ConocoPhillips. Additional financing has been obtained through a $383.0 million private placement note issuance by Freeport LNG which closed on December 19, 2005. The funds from the notes are being used to fund the balance of the Phase I construction of Freeport LNG s liquefied natural gas regasification terminal. The funds will also be used to fund the development of an integrated natural gas storage salt cavern and a portion of the cost of an expansion of the LNG terminal (Phase II). The notes are secured primarily by payments obligated under the terminal use agreement with Dow Chemical.

Phase II expansion of the LNG terminal may include a second LNG unloading dock, additional send-out and additional storage capacity. Freeport LNG submitted a permit application for the expansion to the FERC in May, 2005. FERC approved the expansion permit on September 26, 2006. Expansions of the terminal included in the current authorizations are planned and will be constructed as additional capacity is sold.

Although we anticipate that we may, from time-to-time, be required to provide funds to the Freeport LNG project, and intend to provide our pro rata 10% of any required equity participation, we believe the project will continue through Phase I construction and Phase II pre-development with no further significant funds likely being required from Contango.

Contango Venture Capital Corporation

As of June 30, 2007, Contango Venture Capital Corporation (CVCC), our wholly-owned subsidiary, held a direct investment in three alternative energy portfolio companies: Gridpoint, Inc. (Gridpoint), Moblize Inc. (Moblize) and Trulite Inc. (Trulite). Our investment in Gridpoint is less than a 20% ownership interest and we account for this investment under the cost method. Our investment in Moblize rose above a 20% ownership interest during the three months ended September 30, 2006 when the Company exercised its right pursuant to two warrants, to purchase additional shares of Moblize. We account for this investment under the equity method. Trulite is a publicly traded company. We account for this investment in accordance with Statement of Financial Accounting Standard (SFAS) No. 115 (SFAS 115), Accounting for Certain Investments in Debt and Equity Securities .

Gridpoint, Inc. As of June 30, 2007, CVCC had invested approximately $1.0 million in Gridpoint in exchange for 333,333 shares of Gridpoint preferred stock, which represents an approximate 1.8% ownership interest. Gridpoint s intelligent energy management products ensure clean, reliable power, increase energy efficiency, and integrate renewable energy. With Gridpoint, home and business owners can protect themselves from power outages, manage their energy online and reduce their carbon footprint.

Moblize Inc. As of June 30, 2007, CVCC had invested $1.2 million in Moblize in exchange for 648,648 shares of Moblize convertible preferred stock, which represents an approximate 33% ownership interest. Moblize develops real time diagnostics and field optimization solutions for the oil and gas and other industries using open-standards based technologies. Moblize has deployed its technology on our Grand Isle 72 well which allows COI to remotely monitor, control and record, in real time, daily production volumes. Moblize is continuing to deploy its technology on oil fields near Houston belonging to Chevron U.S.A. Inc. and on other COI operated wells.

Trulite, Inc. As of June 30, 2007, CVCC had invested $0.9 million in Trulite in exchange for 2,001,014 shares of Trulite common stock, which represents an approximate 17% ownership interest. Trulite develops lightweight hydrogen generators for fuel cell systems, and recently began trading publicly on the over the counter bulletin board under the stock symbol TRUL.OB . As a result, we mark-to-market our investment in Trulite based on public pricing. At June 30, 2007, our investment in Trulite had a mark-to-market value of approximately $2.0 million based on a closing stock price of $1.00 per share. Trulite is a startup company with very little trading volume and thus the purchase or sale of relatively small common stock positions may result in disproportionately large increases or decreases in the price of its common stock. An unrealized gain of $0.7 million, net of tax, has been reflected as a component of other comprehensive income at June 30, 2007.

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As of June 30, 2007, the Company had loaned Trulite approximately $1.0 million under various promissory notes, with various due dates. The notes initially bear interest at a per annum rate of 11.25%, before changing to Prime plus 3% and then Prime plus 4%. For the fiscal year ended June 30, 2007, the Company earned and accrued approximately $55,000 in interest income from the Trulite notes. Please see Note 18 Related Party Transactions of Notes to Consolidated Financial Statements included as part of this Form 10-K, for a discussion of our promissory notes with Trulite.

As of June 30, 2007, CVCC owned 25% of Contango Capital Partners Fund, L.P. (the Fund). The Fund currently holds a direct investment in two alternative energy companies Protonex Technology Corporation (Protonex) and Jadoo Power Systems (Jadoo). We account for our investment in the Fund under the equity method. The Fund, however, accounts for its investment in Protonex in accordance with SFAS 115, and accounts for its investment in Jadoo at fair value in accordance with the AICPA Audit and Accounting Guide, Investment Companies .

Protonex Technology Corporation. As of June 30, 2007, the Fund had invested $1.5 million in Protonex in exchange for 2,400,000 shares of Protonex common stock, which represents an approximate 7% ownership interest. Protonex provides long-duration portable and remote power sources with a focus on providing solutions to the U.S. military and supplies complete power solutions and application engineering services to original equipment manufacturers customers. Protonex trades its common shares on the AIM market of the London Stock Exchange under the stock symbol PTX.L . As a result, the Fund marks-to-market its investment in Protonex based on public pricing. At June 30, 2007, the Fund s investment in Protonex had a mark-to-market value of approximately $4.4 million ($1.1 million net to Contango s interest).

Jadoo Power Systems. As of June 30, 2007, the Fund has invested approximately $1.2 million and owns 2,200,000 shares of Jadoo common stock, which represents an approximate 5% ownership interest. Jadoo develops high energy density power products for the law enforcement, military and electronic news gathering applications. During the fourth quarter of our fiscal year ended June 30, 2007, the management of Jadoo determined that the company was impaired. The Fund therefore incurred an impairment charge of $1.2 million ($0.3 million net to Contango) for the fiscal year ended June 30, 2007, related to our investment in Jadoo.

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. 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
- Potential price controls and special taxes

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.

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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 based on 15% of its natural gas and oil gross income from such properties (up to an aggregate of 1,000 barrels per day of domestic crude oil and/or equivalent units of domestic natural gas).

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.

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 these financial responsibility requirements under the 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 onshore 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.

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.

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The MMS administers the natural gas and oil leases held by the Company on federal onshore lands and offshore tracts in the Outer Continental Shelf. The MMS 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 MMS 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 MMS requires companies operating on the Outer Continental Shelf to obtain surety bonds to ensure performance of these obligations. Prior to the Company s decision to act as the operator in the drilling of offshore prospects, the Company was required by the MMS to obtain surety bonds, typically providing $50,000 in coverage per lease, an amount of coverage that ensures a minimum level of performance. As an operator, however, the Company is required to obtain surety bonds of $200,000 per lease for exploration and $500,000 per lease for developmental activities.

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 on the Company than it will on other similarly situated natural gas producers and sellers.

Government Regulation of LNG Operations. Our LNG operations are subject to extensive regulation under federal, state and local statutes, rules, regulations and other laws. Among other matters, these laws require the acquisition of certain permits and other authorizations before commencement of construction and operation of an LNG receiving terminal. Failure to comply with such rules, regulations and laws could result in substantial penalties.

In order to site, construct and operate the Freeport LNG receiving terminal, authorization from the FERC under Section 3 of the Natural Gas Act of 1938 (the NGA) was required. The FERC permitting process includes detailed engineering and design work, extensive data gathering, preparation and final issuance of an Environmental Impact Statement under the National Environmental Policy Act, and public notices and opportunities for public hearings relating to:

- Siting requirements
- Design standards
- Construction standards
- Equipment, operations and maintenance
- Personnel qualifications and training
- Fire protection
- Security

The FERC approved the project in June 2004. On January 2005, the FERC granted Freeport LNG authorization under Section 3 of the NGA to site, construct and operate an LNG receiving terminal and to construct a 9.6 mile pipeline, together with related facilities, in Brazoria County, Texas. In September 2006, Freeport LNG received FERC authorization to expand the terminal s capacity. The Freeport LNG send-out pipeline will not interconnect with any interstate natural gas pipelines and will not be used to provide interstate transportation service under the NGA.

Other Federal Governmental Permits, Approvals and Consultations. In addition to the FERC authorization under Section 3 of the NGA, the construction and operation of LNG receiving terminals is also

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subject to additional federal and state permits, approvals and consultations including: Texas Commission on Environmental Quality, U.S. Coast Guard, U.S. Army Corps of Engineers, U.S. Department of Commerce, National Marine Fisheries Services, U.S. Department of the Interior, U.S. Fish and Wildlife Service, U.S. Environmental Protection Agency (the EPA) and U.S. Department of Homeland Security and the Advisory Counsel on Historic Preservation.

Environmental Matters. LNG operations are subject to various federal, state and local laws and regulations relating to the protection of the environment. In some cases, these laws and regulations could require Freeport LNG to obtain governmental authorizations before conducting certain activities or may require Freeport LNG to limit certain activities in order to protect endangered or threatened species or sensitive areas. These environmental laws may impose substantial penalties for noncompliance and substantial liabilities for pollution. As with the industry generally, compliance with these laws increases the overall cost of business. Environmental regulations have historically been subject to frequent change. Consequently, we are unable to predict the future costs or other future impacts of environmental regulations.

Employees

We have six employees, all of whom are full time. 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 our alliance partners 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 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	62	Chairman, President, Chief Executive Officer, Chief Financial Officer, Secretary and Director
Lesia Bautina	36	Senior Vice President and Controller
Sergio Castro	38	Vice President and Treasurer
Marc Duncan	54	President & Chief Operating Officer, Contango Operators, Inc.
B.A. Berilgen	59	Director
Jay D. Brehmer	42	Director
Charles M. Reimer	62	Director
Steven L. Schoonover	62	Director
Darrell W. Williams	64	Director

Kenneth R. Peak. Mr. Peak is the founder and has been Chairman, Chief Executive Officer and Chief Financial Officer of Contango since its formation in September 1999. Mr. Peak entered the energy industry in 1972 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.

Lesia Bautina. Ms. Bautina joined Contango in November 2001 as Controller and was appointed Vice President and Controller in August 2002. In July 2005, Ms. Bautina was promoted to Senior Vice President. Prior to joining Contango, Ms. Bautina worked as an auditor for Arthur Andersen LLP from 1997 to 2001. Her primary experience is accounting and financial reporting for exploration and production companies. Ms. Bautina received a degree in History from the University of Lvov in the Ukraine in 1990 and a BBA in Accounting in 1996 from Sam Houston State University, where she graduated with honors. Ms. Bautina is a Certified Public Accountant and member of the Petroleum Accounting Society of Houston.

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Sergio Castro. Mr. Castro joined Contango in March 2006 as Treasurer and was appointed Vice President and Treasurer in April 2006. Prior to joining Contango, Mr. Castro spent two years as a Consultant for UHY Advisors TX, LP. From 2001 to 2004, Mr. Castro was a lead credit analyst for Dynegy Inc. From 1997 to 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 Certified Public Accountant and a Certified Fraud Examiner.

Marc Duncan. Mr. Duncan joined Contango in June 2005 as President and Chief Operating Officer of Contango Operators, Inc. Mr. Duncan has over 25 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 in a senior executive position with USENCO International, Inc. and related companies in China and Ukraine from 2000-2004 and as a senior project and drilling engineer for Hunt Oil Company from 2004-2005. 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.

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 37 year career. Most recently, he was Chairman, CEO and President of Rosetta Resources Inc., a company he founded in 2005. Prior to that, he was 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 B.S. in Petroleum Engineering in 1970 and a M.S. in Industrial Engineering / Management Science.

Jay D. Brehmer. Mr. Brehmer has been a director of Contango since October 2000. Mr. Brehmer is Managing Director of Houston Capital Advisors LP, a boutique financial advisory, merger and acquisition investment bank. From November 2002 until August 2004, he advised various energy and energy-related companies on corporate finance and merger and acquisition activities through Southplace, LLC. 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 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 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 2005. Mr. Schoonover currently serves as Chief Executive Officer of Cellxion, L.L.C., a company specializing in construction and installation of telecommunication buildings and towers, as well as the installation of high-tech telecommunication equipment. 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.

Darrell W. Williams. Mr. Williams has been a director of Contango since 1999. From 2005 through 2007, Mr. Williams was President and CEO of Porta-Kamp International LP, which specializes in the manufacture, supply and construction of remote area housing, and CEO of Clearwater Environmental Systems, a manufacturer of sewage and water treatment systems. From 2002 until 2005, Mr. Williams was Managing Director of Catalina Capital Advisors, LP. Prior to joining Catalina, Mr. Williams was in senior executive positions with Deutug Drilling, GmbH (1993-2002), Nabors Drilling (1988-1993), Pool Company (1985-1988), Baker Oil Tools (1980-1983), SEDCO (1970-1980), Tenneco (1966-1970), and Humble Oil (1964-1966). Mr. Williams graduated from West Virginia University with a degree in Petroleum Engineering in 1964. Mr. Williams is past Chairman of the Houston Chapter of International Association of Drilling Contractors, a life member of the Society of Petroleum Engineers and a registered professional engineer in Texas.

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 in November 2006, each outside director of the Company receives a quarterly retainer of $8,000 payable in cash and $36,000 annually payable in Company common stock. Each outside director also receives a $1,000 cash payment for each board meeting and separately scheduled Audit Committee meeting attended. The Chairman of the Audit Committee receives an additional quarterly cash payment of $3,000. 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. On September 30, 2006 we extended the term of our lease agreement for an additional 60 months, commencing November 1, 2006, with a termination date of October 31, 2011.

Code of Ethics

We adopted a Code of Ethics for senior management in December 2002. 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

General information about us can be found on our Website at www.contango.com. Our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our Website as soon as reasonably practicable after we file or furnish them to the Securities and Exchange Commission.

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. The risk factors listed below are not all inclusive.

We have no ability to control the prices that we receive for natural gas and oil. Natural gas and oil prices fluctuate widely, and low prices would have a material adverse effect on our revenues, profitability and growth.

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. Lower prices may also affect the amount of natural gas and oil that we can economically produce. Factors that can cause price fluctuations include:

- 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.
Potential price controls and special taxes.
Access to pipelines and gas processing plants.

We depend on the services of our chairman, chief executive officer and chief financial officer, and implementation of our business plan could be seriously harmed if we lost his services.

We depend heavily on the services of Kenneth R. Peak, our chairman, chief executive officer, and chief financial officer. We do not have an employment agreement with Mr. Peak, and 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 our alliance partners and could be seriously harmed if our alliance agreements were terminated.

Because we have only six employees, none of whom are geoscientists or petroleum engineers, we are dependent upon alliance partners for the success of our natural gas and oil exploration projects and expect to remain so for the foreseeable future. Highly qualified explorationists and engineers are difficult to attract and retain. As a result, the loss of the services of one or more of our alliance partners could have a material adverse effect on us and could prevent us from pursuing our business plan. Additionally, the loss by our alliance partners 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, we cannot be certain that additional financing will be available to us on acceptable terms, if at all. In particular, our credit facility imposes limits on our ability to borrow under the facility based on adjustments to the value of our hydrocarbon reserves, and our credit facility limits our ability to incur additional indebtedness. 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.

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

The Company, since its inception in September 1999, has raised $87.0 million in proceeds from eight separate 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 wells in the Gulf of Mexico.

Contango Operators, Inc. (COI) is a wholly-owned subsidiary of the Company, formed for the purpose of drilling and operating exploration wells in the Gulf of Mexico. COI is currently the operator for our

Dutch and Mary Rose prospects. Although as a company we have previously taken working interests in offshore prospects, our recent exploration prospects are the first wells in which we have assumed the role of operator. Estimated drilling costs could be significantly higher if we encounter difficulty in drilling offshore exploration wells.

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. The Company s drilling operations may be curtailed, delayed, canceled or negatively impacted as a result of numerous factors, including inexperience as an operator, 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 we cannot assure that new wells will be productive or that we will recover all or any portion 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.

Most of our revenues and production are from our Dutch wells and we depend upon outside third parties to operate and maintain our production, pipelines and processing facilities.

We depend upon the services of others to drill and complete our wells, and operate production platforms, pipelines, gas processing facilities and the infrastructure required to produce and market our natural gas, condensate and oil. As a result, we have no control over how frequently and how long our production is shut-in when production problems, weather and other production shut-ins occur. As we have ramped up production at our Dutch #1 and Dutch #2 wells, and as we prepare to begin production at our Dutch #3 well, we have had to increase the production handling capacity of related downstream infrastructure necessary to produce these wells at their designed flow rates. As a consequence, we have incurred a number of production shut-ins which have negatively affected our near term revenues and cash flow.

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

Our Dutch #1 and Dutch #2 well bores are required to be shut-in from time to time due to a combination of weather, mechanical problems and shut-ins necessary to upgrade and increase 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 could have the potential to 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 to recover our reserves.

We have significant resources committed to our Arkansas Fayetteville Shale play.

Our Arkansas Fayetteville Shale play proved reserves at June 30, 2007 were approximately 15.2 Bcf. Since inception, we have expended approximately $48.0 million in the Fayetteville Shale play ($9.5 million in lease acquisitions, $34.2 million in drilling and completion activities and $4.3 million in dry hole costs), while our revenues from the play from inception through the production month of June 2007 have totaled only $4.2 million. There can be no assurance that our drilling activity in this area will produce economically feasible wells. Our capital budget for fiscal year 2008 calls for us to invest an additional $25.6 million in the Arkansas Fayetteville Shale. This represents approximately 46% of our total CAPEX budget for the next twelve months. We intend to continue to borrow significant capital against anticipated revenues and production, and should the wells not perform as expected, we could encounter difficulty repaying this debt. It is early in the exploration and development of this play, there is a lack of oil field service infrastructure in the area, and we are still learning how to most efficiently drill, complete, fracture stimulate and produce these wells. Some of our wells have taken considerably longer than expected to drill, and we have had significant cost overruns. All of our wells are operated by others and as a result, we have a limited ability to exercise influence over operations or their associated costs.

We are highly dependent on the lending availability of a single company.

Our $30.0 million Term Loan Agreement and REX s $50.0 million demand note are with the same private investment firm. Contango had no amounts outstanding under the Term Loan Agreement and REX had borrowed $31.0 million under its demand note as of August 31, 2007. Should the private investment firm encounter difficulties funding future requested advances, some portion or all of the $49.0 million of capital that remains unfunded may no longer be available. In that case, we would be forced to seek alternative and possibly more expensive financing, which may or may not be available.

REX s $50 million note is payable upon demand by the lender.

REX s $50.0 million demand note with the private investment firm is payable upon demand. Should the private investment firm decide to call the note, REX does not have the funds available to repay its borrowings. In that case, REX would be forced to seek alternative and possibly more expensive financing, which may or may not be available, or risk losing the assets it has pledged as collateral, including its interest in the Dutch and Mary Rose prospects.

We have outsourced the marketing of our production and the vast majority of our revenues are from one purchaser, Cokinos Energy Corporation.

A significant portion of the Company s production is sold to Cokinos Energy Corporation. These sales to Cokinos Energy Corporation are secured with letters of credit.

Our capital exploration is focused on two highly capital intensive prospect areas which increases our risk of incurring significant losses.

Beginning in the spring of 2005, we have continued to increase our capital investment in just two exploration prospects, our onshore Arkansas Fayetteville Shale prospect and our offshore Gulf of Mexico prospects. Both of these investments represent a major increase in the risk profile of the Company.

The construction of our LNG receiving terminal in Freeport, Texas is subject to various development and completion risks.

We own a 10% limited partnership interest in the Freeport LNG receiving facility being constructed in Freeport, Texas. The LNG project received approval from the FERC in June 2004. On January 11, 2005, Freeport LNG received its authorization to commence construction of the first phase of its terminal from the FERC. Construction of the 1.75 Bcf/d facility commenced on January 17, 2005. Freeport LNG received FERC authorization in September 2006 for an expansion that would increase the permitted capacity from its current level of 1.75 Bcf/d up to as much as 4.0 Bcf/d. The LNG receiving facility is subject to development risk such as permitting, cost overruns and delays. Key factors that may affect the completion of the LNG receiving terminal include, but are not limited to: timely issuance of necessary additional permits, licenses and approvals by governmental agencies and third parties; sufficient financing; unanticipated changes in market demand or supply; competition with similar projects; labor disputes; site difficulties; environmental conditions; unforeseen events, such as hurricanes, explosions, fires and product spills; delays in manufacturing and delivery schedules of critical equipment and materials; resistance in the local community; local and general economic conditions; and commercial arrangements for pipelines and related equipment to transport and market LNG.

If completion of the LNG receiving facility is delayed beyond the estimated development period, the actual cost of completion may increase beyond the amounts currently estimated in our capital budget. A delay in completion of the LNG receiving facility would also cause a delay in the receipt of revenues projected from operation of the facility, which may cause our business, results of operations and financial condition to be substantially harmed.

If we are not able to fund or finance our 10% ownership in the LNG receiving terminal in Freeport, Texas, including any expansion of the terminal, we may lose our 10% investment in the project.

A majority of the Freeport LNG construction costs is being provided by ConocoPhillips. Upon any significant increase in construction costs to complete construction of the receiving terminal or upon a call to fund construction of the proposed expansion, we may not have the financial resources to fund our 10% ownership share of construction costs. If we are unable to fund our share of the project costs or if the project is unable to secure third-party project financing, we could lose our investment in the project or be forced to sell our interest in an untimely fashion or on less than favorable terms.

If we default on our loan from the Royal Bank of Scotland plc we could lose our 10% investment in the LNG receiving terminal in Freeport, Texas.

Our three-year $20.0 million term loan agreement dated April 27, 2006 with The Royal Bank of Scotland plc is secured with the stock of Contango Sundance, Inc. (Sundance), our wholly-owned subsidiary. Sundance owns a 10% limited partnership interest in Freeport LNG Development, LP, which owns the Freeport LNG terminal. If an event of default occurs under the term loan agreement, we could lose our investment in the Freeport LNG terminal.

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 would 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 and present values of our reserves.

The process of estimating natural gas and oil reserves is complex. 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 and present value 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. Therefore, estimates of natural gas and oil reserves are inherently imprecise.

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 this 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. Most of the producing wells included in our reserve report have produced for a relatively short period of time. Because some of our reserve estimates are not based on a lengthy production history and are calculated using volumetric analysis, these estimates are less reliable than estimates based on a more lengthy production history.

You should not assume that the pre-tax net present value of our proved reserves prepared in accordance with SEC guidelines referred to in this report is the current market value of our estimated natural gas and oil reserves. We base the pre-tax net present value of future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices, costs, taxes and the volume of produced reserves will likely differ materially from those used in the pre-tax net present value estimate.

The proved reserves assigned to our Dutch and Mary Rose discoveries have only two producing well bores that, as of August 31, 2007, had only seven months of production history. Reserve assessments based on only two well bores with limited production history are subject to greater risk of downward revision than multiple well bores from a mature producing reservoir.

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

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 engineers. If those reports prove to be inaccurate, our financial reports could have material misstatements. Further, we use the reports of our independent reservoir engineers in our financial planning. If the reports of the outside reservoir engineers prove to be inaccurate, we may make misjudgments in our financial planning.

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

Our future success will largely depend 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 or irregularities in formations.
- Equipment failures or accidents.
- 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 which 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.

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The natural gas and oil business involves many operating risks that can cause substantial losses.

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.
- 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.

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, and in some cases offshore platforms, which we do not own. Transportation capacity on gathering system

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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 have no assurance of title to our leased interests.

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 our alliance partners 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. We have no assurance, however, that any such deficiencies have been cured by the operator of any 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 most 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. Most 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 will depend on our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most 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.

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 may:

- 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

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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 factual 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.

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

Other companies currently 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.

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.
- 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, particularly those of the acquired organization.

Anti-takeover provisions of our certificate of incorporation, bylaws and Delaware law could adversely effect 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. These provisions, among other things, authorize the board of directors to:

- Designate the terms of and issue new series of preferred stock.
- Limit the personal liability of directors.
- Limit the persons who may call special meetings of stockholders.
- Prohibit stockholder action by written consent.
- Establish advance notice requirements for nominations for election of the board of directors and for proposing matters to be acted on by stockholders at stockholder meetings.
- Require us to indemnify directors and officers to the fullest extent permitted by applicable law.
- Impose restrictions on business combinations with some interested parties.

Our common stock is thinly traded.

Contango has approximately 16 million shares of common stock outstanding, held by approximately 120 holders of record. Directors and officers own or have voting control over approximately 3.3 million shares. Since our common stock is thinly traded, the purchase or sale of relatively small common stock positions may result in disproportionately large increases or decreases in the price of our common stock.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Description of Properties***

Production, Prices and Operating Expenses

The following table presents information regarding the production volumes, average sales prices received and average production costs associated with our sales of natural gas, oil and natural gas liquids (NGLs) for the periods indicated. 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.

	Year Ended June 30,		
	2007	**2006**	**2005**
Production:			
Natural gas (million cubic feet)	2,452	91	71
Oil, condensate and NGLs (thousand barrels)	39	4	8
Total (million cubic feet equivalent)	2,686	115	119
Natural gas (thousand cubic feet per day)	6,718	249	195
Oil, condensate and NGLs (barrels per day)	107	11	22
Total (thousand cubic feet equivalent per day)	7,360	315	327
Average sales price:			
Natural gas (per thousand cubic feet)	$ 6.68	$ 7.15	$ 8.40
Oil, condensate and NGLs (per barrel)	$ 59.67	$ 61.53	$ 58.93
Total (per thousand cubic feet equivalent)	$ 6.96	$ 8.00	$ 9.15
Selected data per Mcfe:			
Total lease operating expenses	$ 0.62	$ 0.11	$ 0.17
General and administrative expenses	$ 2.55	$ 41.40	$ 30.01
Depreciation, depletion and amortization of natural gas and oil properties	$ 1.08	$ 2.03	$ 2.96

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Development, Exploration and Acquisition Capital 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, 2007	2006	2005
Property acquisition costs:			
Unproved	$ 3,571,830	$ 14,609,232	$ 248,634
Proved	-	-	-
Exploration costs	72,888,603	19,529,607	9,428,002
Developmental costs	1,453,066	590,395	-
Capitalized interest	1,083,693	149,365	-
Total costs	$ 78,997,192	$ 34,878,599	$ 9,676,636

Drilling Activity

The following table shows our drilling activity for the periods indicated. 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.

	Year Ended June 30, 2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive (onshore)	60	9.9	11	2.0	4	1.4
Productive (offshore)	4	1.6	1	0.6	-	-
Non-productive (onshore)	4	0.6	3	2.8	8	3.6
Non-productive (offshore)	1	0.4	2	0.9	1	0.1
Total	69	12.5	17	6.3	13	5.1

(1) The Company has not drilled any development wells since fiscal year 2004, when it drilled one gross development well (0.8 net developmental wells). The well was a productive well.

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, 2007:

	Developed Acreage (1)(2)		Undeveloped Acreage (1)(3)	
	Gross (4)	Net (5)	Gross (4)	Net (5)
Onshore Arkansas	3,636	2,545	41,664	29,165
Onshore Alabama, Louisiana and Texas	140	98	6,090	4,263
Offshore Gulf of Mexico	15,000	4,297	264,127	141,030
Total	18,776	6,940	311,881	174,458

(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).

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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 its partially owned subsidiaries. The above table includes (i) our 42.7% interest in Republic Exploration LLC s 2,844 net developed acres and 122,376 net undeveloped acres, (ii) our 76.0% interest in Contango Offshore Exploration LLC s 3,000 net developed acres and 92,131 net undeveloped acres, and (iii) our 50% interest in Magnolia Offshore Exploration LLC s 1,920 net undeveloped acres. In addition, the Company holds royalty interests in approximately 36,441 gross undeveloped acres (1,179 net undeveloped acres) and 9,651 gross developed acres (227 net developed acres), offshore in the Gulf of Mexico.

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, 2007:

	Total Productive Wells (1)	
	Gross (2)	**Net (3)**
Natural gas (onshore)	85	11.5
Natural gas (offshore)	8	2.0
Oil	-	-
Total	93	13.5

(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.

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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, 2007, based on a reserve reports generated by William M. Cobb & Associates, Inc. and W.D. Von Gonten & Co. The pre-tax net present value, discounted at 10%, 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 prepared in accordance with SEC guidelines as of June 30, 2007 was based on $6.80 per million British thermal units (MMbtu) for natural gas at the NYMEX and $70.68 per barrel of oil at the West Texas Intermediate Posting, in each case before adjusting for basis, transportation costs and British thermal unit (Btu) content. For further information concerning the present value of future net cash flows from these proved reserves, see Supplemental Oil and Gas Disclosures .

	Total Proved Reserves as of June 30, 2007				
	Producing	Non-Producing	Behind Pipe	Undeveloped	Total
Onshore					
Natural gas (MMcf)	7,677	4,268	129	3,315	15,389
Oil and condensate (MBbls)	2	-	4	-	6
Total proved reserves (MMcfe)	7,689	4,268	153	3,315	15,425
Pre-tax net present value ($000) (Disc. @ 10%)	$ 21,215	$ 10,635	$ 923	$ 3,372	36,145
Offshore					
Natural gas (MMcf)	17,625	27,963	59	16,856	62,503
Oil and condensate (MBbls)	344	475	2	337	1,158
Total proved reserves (MMcfe)	19,689	30,813	71	18,878	69,451
Pre-tax net present value ($000) (Disc. @ 10%)	$ 97,322	$ 139,874	$ 387	$ 55,451	293,034
Total					
Natural gas (MMcf)	25,302	32,231	188	20,171	77,892
Oil and condensate (MBbls)	346	475	6	337	1,164
Total proved reserves (MMcfe)	27,378	35,081	224	22,193	84,876
Pre-tax net present value ($000) (Disc. @ 10%)	$ 118,537	$ 150,509	$ 1,310	$ 58,823	329,179

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 can vary. Therefore, estimates of natural gas and oil reserves are inherently imprecise. 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.

It should not be assumed that the pre-tax net present value is the current market value of our estimated natural gas and oil reserves. In accordance with requirements of the Securities and Exchange Commission, we base the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

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Item 3. ***Legal Proceedings***

As of the date of this Form 10-K, we are not a party to any legal proceedings and we are not aware of any proceeding contemplated against us.

Item 4. ***Submission of Matters to a Vote of Security Holders***

During the quarter ended June 30, 2007, no matters were submitted to a vote of security holders.

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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 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 2006:		
Quarter ended September 30, 2005	$ 12.10	$ 9.52
Quarter ended December 31, 2005	$ 13.82	$ 9.87
Quarter ended March 31, 2006	$ 13.58	$ 11.40
Quarter ended June 30, 2006	$ 14.14	$ 11.85
Fiscal Year 2007:		
Quarter ended September 30, 2006	$ 14.45	$ 11.47
Quarter ended December 31, 2006	$ 24.09	$ 10.46
Quarter ended March 31, 2007	$ 22.49	$ 19.74
Quarter ended June 30, 2007	$ 39.35	$ 21.38

On August 31, 2007, the closing price of our common stock on the American Stock Exchange was $36.60 per share, and there were approximately 16 million shares of Contango common stock outstanding, held by approximately 120 holders of record.

We have not declared or paid any dividends on our shares of common stock and do not currently anticipate paying any dividends on our shares of common stock in the future. Currently, except for the regular dividends that we pay on our preferred stock, our plan is to retain any future earnings for use in the operations and expansion of our natural gas and oil exploration business and as needed in our LNG and alternative energy activities. Our credit facilities currently prohibit us from paying any cash dividends on our common stock. The credit facilities do, however, permit the payment of stock dividends on our 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.

On July 15, 2005, we sold $10.0 million of our Series D preferred stock to a group of private investors. The Series D preferred stock was perpetual and cumulative, was senior to our common stock and was convertible at any time into shares of our common stock at a price of $12.00 per share. The dividend on the Series D preferred stock was paid quarterly in cash at a rate of 6.0% per annum or could be paid-in-kind at a rate of 7.5% per annum. Our registration statement filed with the Securities and Exchange Commission, covering the 833,330 shares of common stock issuable upon conversion of the Series D preferred stock, became effective on October 26, 2005.

In November 2006, two Series D preferred stockholders voluntarily elected to convert a total of 100 shares of Series D preferred stock to 41,666 shares of our common stock. The converted shares of Series D preferred stock had a face value of $0.5 million.

On January 15, 2007, we exercised our mandatory conversion rights pursuant to the terms of our Series D preferred stock, and converted all of the remaining 1,900 shares of our Series D preferred stock issued and outstanding into 791,664 shares of our common stock. The outstanding shares of the Series D preferred stock had a face value of $9.5 million.

On May 17, 2007, we sold $30.0 million of our Series E preferred stock to a group of private investors. The sale of the Series E preferred stock was exempt from registration pursuant to Section 4(2) of the Securities Act of 1933 and Regulation D promulgated thereunder, as a transaction not involving a public offering. The Series E preferred stock is perpetual and cumulative, is senior to our common stock and is convertible at any time by the holder into shares of our common stock at a price of $38.00 per share. The dividend on the Series E preferred stock can be paid quarterly in cash at a rate of 6.0% per annum or paid-in-kind at a rate of 7.5% per

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annum. We used the net proceeds to repay $15.0 million in debt outstanding from the Company s $30.0 million term loan agreement and to fund the Company s offshore Gulf of Mexico deep shelf exploration program and our Arkansas Fayetteville Shale play. We have filed a registration statement with the Securities and Exchange Commission, covering the 789,468 shares of common stock issuable upon conversion of the Series E preferred stock, which became effective on September 12, 2007.

The following table sets forth information about our equity compensation plan at June 30, 2007:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans
1999 Stock Incentive Plan	1,026,000	$ 10.87	1,037,333

No equity securities of the Company were repurchased during the fiscal year ended June 30, 2007. We do not have a publicly announced program to repurchase shares of our common stock.

The following graph compares the yearly percentage change from June 30, 2002 until June 30, 2007 in the cumulative total stockholder return on our common stock to the cumulative total return on the Russell 2000 Stock Index and a peer group of five independent oil and gas exploration companies selected by us. The companies in our selected peer group are Brigham Exploration Company, Carrizo Oil & Gas, Inc., Edge Petroleum Corp., Goodrich Petroleum Corp. and PetroQuest Energy, Inc. Our common stock began trading on the American Stock Exchange on January 19, 2001 and previously 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, 2002 and that all dividends were reinvested. The stock performance for our common stock is not necessarily indicative of future performance.