LEGACY RESERVES LP
Form 424B5
November 09, 2012

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Title of Each Class to be Registered	Amount to Be Registered (1)	Offering Price per Unit	Aggregate Offering Price	Registration Fee (2)(3)
Units representing limited partner interests	10,005,000	$24.80	$248,124,000	$33,845

(1) Assumes that the over-allotment amount of 1,305,000 units is exercised.

(2) Calculated in accordance with Rule 457(r) under the Securities Act of 1933, as amended (the "Securities Act").

(3) This "Calculation of Registration Fee" table shall be deemed to update the "Calculation of Registration Fee" table in the Company's Registration Statement on Form S-3 (File No. 333-174434) in accordance with Rules 456(b) and 457(r) under the Securities Act.

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Filed Pursuant to Rule 424(b)(5)
Registration No. 333-174434

PROSPECTUS SUPPLEMENT
(To the Prospectus dated September 6, 2011)

8,700,000 Units

LEGACY RESERVES LP

Representing Limited Partner Interests

We are selling 8,700,000 units representing limited partner interests of Legacy Reserves LP. Our units trade on the NASDAQ Global Select Market under the symbol "LGCY." The last reported sales price of our units on the NASDAQ Global Select Market on November 8, 2012 was $24.80 per unit.

Investing in our units involves risks. You should carefully consider each of the factors described under "Risk Factors" beginning on page S-14 of this prospectus supplement and on page 3 of the accompanying prospectus.

We have granted the underwriters a 30-day option to purchase up to an additional 1,305,000 units from us on the same terms and conditions as set forth above if the underwriters sell more than 8,700,000 units in this offering.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus supplement or the accompanying prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

	Per Unit	Total
Public offering price	$ 24.800	$ 215,760,000
Underwriting discounts and commissions	$ 0.992	$ 8,630,400
Proceeds, before expenses, to Legacy Reserves LP	$ 23.808	$ 207,129,600

The underwriters expect to deliver the units on or about November 15, 2012.

Joint Book-Running Managers

Wells Fargo Securities **Barclays** **BofA Merrill Lynch**

Citigroup **J.P. Morgan** **Raymond James**

RBC Capital Markets **UBS Investment Bank**

Co-Managers

Baird	**Stifel Nicolaus Weisel**	**Global Hunter Securities**
Janney Montgomery Scott	**MLV & Co.**	**Wunderlich Securities**

The date of this prospectus supplement is November 8, 2012.

PROSPECTUS SUPPLEMENT

PROSPECTUS DATED SEPTEMBER 6, 2011

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Important Notice About Information in This
Prospectus Supplement and the Accompanying Prospectus

This document is in two parts. The first part is the prospectus supplement, which describes the specific terms of this offering and also adds to and updates information contained in the accompanying prospectus and the documents incorporated by reference into this prospectus supplement and the accompanying prospectus. The second part is the accompanying prospectus, which gives more general information about securities we may offer from time to time, some of which may not apply to this offering of units.

If the information relating to the offering varies between the prospectus supplement and the accompanying prospectus, you should rely on the information in this prospectus supplement.

You should rely only on the information contained in or incorporated by reference in this prospectus supplement, the accompanying prospectus and any free writing prospectus prepared by or on behalf of us. We have not, and the underwriters have not, authorized anyone to provide you with additional or different information. If anyone provides you with additional, different or inconsistent information, you should not rely on it. This prospectus supplement and accompanying prospectus are not an offer to sell or a solicitation of an offer to buy our units in any jurisdiction where such offer and any sale would be unlawful. You should not assume that the information contained in this prospectus supplement or the accompanying prospectus is accurate as of any date other than the date on the front of those documents or that any information we have incorporated by reference is accurate as of any date other than the date of the document incorporated by reference. Our business, financial condition, results of operations and prospects may have changed since such dates.

The information in this prospectus supplement is not complete. You should review carefully all of the detailed information appearing in this prospectus supplement, the accompanying prospectus and the documents we have incorporated by reference before making any investment decision.

SUMMARY

This summary highlights information included or incorporated by reference in this prospectus supplement. It does not contain all of the information that may be important to you. You should read carefully the entire prospectus supplement, the accompanying prospectus, the documents incorporated by reference and the other documents to which we refer herein for a more complete understanding of this offering.

Unless the context otherwise requires, references to "Legacy Reserves", "Legacy", "we", "our", "us", or like terms refer to Legacy Reserves LP and its subsidiaries.

Legacy Reserves LP

Overview

We are an independent oil and natural gas limited partnership headquartered in Midland, Texas, and are focused on the acquisition and development of oil and natural gas properties primarily located in the Permian Basin, Mid-Continent and Rocky Mountain regions of the United States. We were formed in October 2005 to own and operate the oil and natural gas properties that we acquired from our Founding Investors and three charitable foundations in connection with the closing of our private equity offering on March 15, 2006. On January 18, 2007, we completed our initial public offering.

Our primary business objective is to generate stable cash flows allowing us to make cash distributions to our unitholders and to support and increase quarterly cash distributions per unit over time through a combination of acquisitions of new properties and development of our existing oil and natural gas properties.

Our oil and natural gas production and reserve data as of December 31, 2011 are as follows:

- We had proved reserves of approximately 63.4 million barrels of crude oil equivalent (MMBoe), of which 68% were oil and natural gas liquids (NGLs) and 85% were classified as proved developed producing (PDP), 2% were proved developed non-producing, and 13% were proved undeveloped;

- Our proved reserves had a standardized measure of $1.1 billion; and

- Our proved reserves to production ratio was approximately 12.6 years based on our average daily net production of 13,750 barrels of oil equivalent per day (Boe/d) (approximately 73% operated) for the three months ended December 31, 2011.

We have grown primarily through two activities: the acquisition of producing oil and natural gas properties and the development of properties in established producing trends. From 2007 through October 31, 2012, we completed 106 acquisitions of oil and natural gas properties for a total of approximately $1.0 billion. These acquisitions of primarily long-lived, oil-weighted assets, along with our ongoing development activities and operational improvements, have allowed us to achieve significant operational and financial growth during this time period.

Business Strategy

The key elements of our business strategy are to:

- *Make accretive acquisitions of producing properties generally characterized by long-lived reserves with stable production and reserve exploitation potential.* We seek to acquire long-lived reserves with moderate production decline rates and reserve exploitation potential that we believe will generate attractive risk-adjusted returns that are accretive to distributable cash flow per unit. Our diverse property base includes numerous fields spread across three geographic producing regions that provide opportunities for "bolt-on" acquisitions and the ability to increase our

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ownership in fields in which we already have a working interest. We also seek to acquire interests in new fields and geographic regions that are consistent with our business strategy. We believe that our experience positions us to identify, evaluate, execute, integrate and exploit suitable acquisitions.

Add proved reserves and maximize cash flow and production through exploitation activities and operational efficiencies. We have a history of growing proved reserves and maximizing production through exploitation activities while remaining focused on operational efficiencies. We have identified a substantial inventory of development drilling opportunities and numerous workover and recompletion opportunities throughout our properties. We intend to pursue such opportunities to increase our proved reserves, production and cash flow in the future.

Maintain a Conservative Capital Structure and Financial Flexibility. Our long-term strategy is to keep our debt at a moderate level and to fund our acquisition program with cash flow from operations, borrowings under our revolving credit facility and the issuance of equity and debt securities. Since our initial public offering we have approximately $477 million through the issuance of our units. We also intend to maintain adequate borrowing capacity under our revolving credit facility. We believe our internally generated cash flows and our borrowing capacity will provide us with the financial flexibility to execute our exploitation activities and pursue additional acquisitions of producing properties.

Reduce Cash Flow Volatility Through Commodity Price Derivatives. We routinely enter into hedge arrangements to reduce the impact of oil and natural gas price volatility on our cash flow from operations. Our strategy includes hedging a significant portion of our future production over a three- to five-year period. With respect to acquisitions, we regularly hedge a high percentage of the acquired production in connection with the execution of the definitive agreement related to the transaction in order to lock-in the expected returns. Our hedge positions are primarily in the form of swap contracts and collars that are designed to provide a fixed price or range of prices between a price floor and a price ceiling.

Competitive Strengths

We believe that we are positioned to successfully execute our business strategy because of the following competitive strengths:

Proven Acquisition Track Record. Since 2007, we have announced or completed 109 acquisitions of producing oil and natural gas properties representing over $1.5 billion in total transaction value. Our acquisition activity has been primarily focused within our three primary operating regions, specifically the Permian Basin, Mid-Continent and Rocky Mountain areas, where we believe we have a distinct competitive advantage. We believe our experience and expertise in making acquisitions will allow us to continue to prudently grow our asset base and business in the future.

Long-Lived, Liquids-Weighted Reserve Base. Our properties are primarily located in mature fields characterized by a long history of stable production and low-to-moderate rates of production decline. As of December 31, 2011 we had proved reserves of approximately 63.4 MMBoe of which 68% were oil and NGLs and 85% were classified as PDP, 2% were proved developed non-producing, and 13% were proved undeveloped. As of December 31, 2011 our proved reserves had a standardized measure of $1.1 billion and a proved reserves to production ratio of approximately 12.6 years based on an average daily net production of 13,750 Boe/d (approximately 73% operated) for the three months ended December 31, 2011.

Diversified Operations and Significant Operational Control. Our producing oil and natural gas assets encompass approximately 6,170 producing wells spanning three geographic producing

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regions, each with established oil and natural gas production histories. For the quarter ended September 30, 2012, we operated approximately 75% of our net daily production of oil and natural gas. Retaining operational control of our assets allows us to leverage our technical and operational expertise to manage overhead, production and drilling costs as well as control the timing and quantity of capital expenditures.

Extensive, Low-Risk Development Drilling Inventory. We have an extensive inventory of low-risk development opportunities throughout our properties, comprised of drilling locations and recompletion and workover opportunities. In 2012, we intend to spend approximately $66 million in capital expenditures on development drilling opportunities and workover and recompletion activities, all of which are targeting oil and NGL projects.

Experienced Management Team with a Vested Interest in Our Success. The members of our management team have an average of over 20 years of experience in the oil and natural gas industry. We believe this experience will help our management team to successfully navigate periods of commodity price volatility and to successfully identify, evaluate, execute, integrate and exploit acquisition opportunities. Additionally, members of our management team, directors and other insiders beneficially own an approximate 21% limited partner interest in us, aligning their interests with those of our investors.

Recent Developments

Pending Acquisition of Oil and Natural Gas Properties in the Permian Basin

On November 7, 2012, we announced the execution of a definitive agreement to purchase Permian Basin oil and natural gas properties from Concho Resources Inc. for $520 million in cash, subject to customary purchase price adjustments (Pending Permian Basin Acquisition). We have internally estimated that as of September 30, 2012, the properties to be acquired in the Pending Permian Basin Acquisition had an estimated 25.6 MMBoe of proved reserves, 71% of which are considered proved developed producing, 14% of which are proved developed non-producing and 62% of which are oil. The properties are expected to produce 5,238 Boe/d in the three months ending March 31, 2013 (our expected first full quarter of ownership) from 1,584 producing wells yielding a total reserve-to-production ratio of approximately 13.4 years. We expect to operate approximately 90.5% of the properties based on proved reserves.

All of the reserves are located in counties in which we currently have operations or are adjacent thereto, and over 99.8% of these reserves are throughout the Permian Basin, including the Lower Abo play and the Deep Rock, Shafter Lake, Fullerton and Ackerly fields. Given the significant geographic overlap with our existing properties, we expect to benefit from our operational expertise and existing field-level infrastructure. We believe the acreage associated with the Pending Permian Basin Acquisition supports substantial long-term development potential including 236 currently identified development locations. The closing is anticipated to occur in December 2012 with an effective date of October 1, 2012 and is subject to customary conditions to closing.

The information presented above is based on our internal evaluation and interpretation of reserve and other information provided to us in the course of our due diligence with respect to the Pending Permian Basin Acquisition and has not been independently verified or estimated.

We anticipate that the Pending Permian Basin Acquisition will add approximately $80 million of cash flow from operations in 2013 assuming (i) average NYMEX oil and natural gas prices of $88.77/Bbl and $4.03/Mcf, respectively, (ii) regional price differentials, and (iii) operating costs of approximately $18.69/Boe, including production and ad valorem taxes and general and administrative expenses.

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While our management believes the estimates of proved reserves, forecasts of production and additions to cash flow, and the underlying assumptions used in determining the foregoing are reasonable based upon its evaluation of information provided in connection with the Pending Permian Basin Acquisition, actual proved reserves, production and cash flow from operations realized in 2013 from the Pending Permian Basin Acquisition will be dependent on actual oil and gas prices, operating costs, well performance and the success of our anticipated developmental drilling program. Any such estimates are inherently uncertain and are subject to significant business, economic, regulatory, environmental and competitive risks and uncertainties that could cause actual results to differ materially from those we anticipate, as set forth under "Forward-Looking Statements" and "Risk Factors Our 2012 acquisitions and our Pending Permian Basin Acquisition may prove to be worth less than we paid, or provide less than anticipated proved reserves, production or cash flow because of uncertainties in evaluating recoverable reserves, well performance, and potential liabilities as well as uncertainties in forecasting oil and gas prices and development, production and marketing costs."

Upon completion of this offering and the application of the net proceeds therefrom to fund a portion of the purchase price of the Pending Permian Basin Acquisition, we expect that the remaining portion of the purchase price will be funded with borrowings under our revolving credit facility or, subject to market conditions, proceeds from the issuance of private or public securities.

2012 Acquisitions

In May 2012 we purchased oil properties in North Dakota and Montana for approximately $69 million in cash. The North Dakota properties are primarily located in Billings County as well as Golden Valley and McKenzie Counties and produce mainly from the Madison, Bakken and Birdbear formations. The Montana properties are located primarily in Blaine County and produce mainly from the Sawtooth and Bowes formations.

Further, from January 1, 2012 through October 1, 2012, we closed an additional 14 acquisitions of oil and natural gas properties for an aggregate purchase price of approximately $58 million as well as prospective acreage acquisitions for approximately $7 million. All acquisitions were funded with borrowings under our revolving credit facility and cash flow from operations.

Set forth below is a summary of our oil and natural gas reserve data as of December 31, 2011 as well as the oil and natural gas reserve data for each of our completed and pending 2012 acquisitions:

Proved Reserves by Operating Region as of December 31, 2011

Operating Regions	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBoe)	% Liquids	% PDP
Permian Basin	28,186	101,176(a)	802	45,851	63.2%	82.0%
Mid-Continent	3,513	18,334	4,000	10,569	71.1%	98.4%
Rocky Mountain	6,411	2,452	10	6,830	94.0%	85.1%
Other	68	642	22	197	45.7%	100.0%
Total	**38,178**	**122,604**	**4,834**	**63,447**	**67.8%**	**85.2%**

(a) We primarily report and account for our Permian Basin natural gas volumes inclusive of the NGL content in those natural gas volumes. Given the price disparity between an equivalent amount of NGLs compared to natural gas, our realized natural gas prices in the Permian Basin are substantially higher than NYMEX Henry Hub natural gas prices due to NGL content.

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2012 Acquisitions Estimated Proved Reserves

	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBoe)	% Liquids	% PDP
Year-To-Date-Acquisitions:(b)						
Permian Basin (March 2012)	46	7		47	97.6%	100.0%
Permian Basin (April 2012)	84	707		202	41.7%	81.6%
Permian Basin (May 2012)	69			69	100.0%	100.0%
Permian Basin (June 2012)	91	2,247	350	816	54.1%	97.5%
Permian Basin (July 2012)	25	42		32	78.4%	100.0%
Permian Basin (August 2012)	76	129		98	78.0%	100.0%
Permian Basin (September 2012)	21	732	140	284	57.0%	100.0%
Permian Basin (October 2012)	571	839	7	718	80.5%	77.4%
Pending Permian Basin Acquisition	15,957	58,091		25,639	62.2%	70.9%
Rocky Mountain (April 2012)	702	76		715	98.2%	100.0%
Rocky Mountain (May 2012)	271	67		282	96.0%	77.8%
Rocky Mountain (May 2012)	3,117	538	76	3,283	97.3%	100.0%
Rocky Mountain (May 2012)	246			246	100.0%	95.2%
Rocky Mountain (August 2012)	166			166	100.0%	100.0%

(b) For each acquisition listed above, reserves were calculated using oil and natural gas prices that represent the unweighted average of the first-day-of-the-month prices for each of the most recent twelve-month period prior to the closing date of each of the acquisitions listed above. For the Pending Permian Basin Acquisition, proved reserves were calculated using a price of $95.33/Bbl for oil, and $2.88/MMBtu for natural gas, which represent the unweighted average of the first-day-of-the-month prices for each of the twelve months ending September 30, 2012, the most recent twelve-month period prior to the anticipated effective date of the Pending Permian Basin Acquisition. The table above excludes two immaterial acquisitions completed in 2012 for approximately $2.8 million.

Borrowing Base Redetermination

On October 1, 2012, the borrowing base under our revolving credit facility was increased from $565 million to $600 million. As of November 6, 2012, we had $462.1 million of borrowings outstanding under our revolving credit facility, resulting in approximately $137.9 million of available borrowing capacity. Our lenders redetermine the borrowing base semi-annually with the next redetermination scheduled on or around April 1, 2013. However, we intend to seek an interim redetermination of the borrowing base in connection with the Pending Permian Basin Acquisition to be effective at the time of closing.

Increase to Quarterly Cash Distribution

On October 22, 2012, the board of directors of our general partner approved a distribution of $0.565 per unit payable on November 14, 2012 to unitholders of record on November 1, 2012. Purchasers of units in this offering will not be entitled to receive a distribution in respect of the third quarter of 2012. This quarterly distribution is a $0.005 per unit increase from the prior quarterly distribution and represents an annualized distribution of $2.26 per unit.

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Our Ownership and Organizational Structure

The chart below depicts our organization and ownership structure as of the date of this prospectus supplement before giving effect to this offering.

Ownership of Legacy Reserves LP

Public Unitholders	78.78%
Founding Investors, Directors and Management	21.18%
General Partner Interest	0.04%
Total	100.00%

(a) Includes entities controlled by Cary Brown, our Chairman, President and Chief Executive Officer, Dale Brown, a Director, and Kyle McGraw, Executive Vice President and Chief Development Officer as well as certain members of Mr. McGraw's family.

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THE OFFERING

Units offered by Legacy Reserves LP	8,700,000 units; 10,005,000 units if the underwriters exercise in full their option to purchase additional units.
Units outstanding after this offering	56,799,419 units, or 58,104,419 units if the underwriters exercise in full their option to purchase additional units.
Use of proceeds	We will receive net proceeds from this offering of approximately $206.8 million, after deducting underwriting discounts and commissions and estimated offering expenses payable by us. We plan to use the net proceeds from the offering and from any exercise of the underwriters' option to purchase additional units to fund a portion of the purchase price of the Pending Permian Basin Acquisition. Prior to funding the Pending Permian Basin Acquisition, we may use some or all of the net proceeds for general partnership purposes, which may include repayment of borrowings outstanding under our revolving credit facility. Please read "Use of Proceeds."
Cash distributions	We distribute all of our cash on hand at the end of each quarter, after payment of fees and expenses, less reserves (including reserves for capital expenditures) established by our general partner in its discretion. Unlike most publicly traded partnerships, we do not pay incentive distributions to our general partner. In general, we distribute 99.96% of our available cash each quarter to our unitholders and approximately 0.04% of our available cash to our general partner. We refer to this cash as "available cash", and we define its meaning in our partnership agreement. On October 22, 2012, the board of directors of our general partner approved a quarterly distribution for the third quarter of 2012 of $0.565 per unit, or $2.26 on an annualized basis, which will be paid on November 14, 2012 to unitholders of record at the close of business on November 1, 2012. Purchasers of units in this offering will not be entitled to the distribution in respect of the third quarter of 2012.

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Conflicts of interest	As described in "Use of Proceeds," affiliates of Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., RBC Capital Markets, LLC and UBS Securities LLC are lenders under our revolving credit facility and may receive more than 5% of the proceeds from this offering pursuant to the repayment of borrowings under that facility. Nonetheless, in accordance with the Financial Industry Authority Rule 5121, the appointment of a qualified independent underwriter is not necessary in connection with this offering because the units offered hereby are interests in a direct participation program. Investor suitability with respect to the units will be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange. Please read "Underwriting Conflicts of Interest."
Estimated ratio of taxable income to distribution	We estimate that if you purchase units in this offering and own them through the record date for the distribution with respect to the fourth calendar quarter of 2014, then you will be allocated, on a cumulative basis, an amount of U.S. federal taxable income for that period that will be less than 20% of the amount of cash distributed to you with respect to that period. If you continue to own units purchased in this offering after that period, the percentage of federal taxable income allocated to you may be higher. Please read "Material Tax Considerations" in this prospectus supplement for the basis of this estimate.
Exchange listing	Our units are traded on the NASDAQ Global Select Market under the symbol "LGCY".

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SUMMARY HISTORICAL CONSOLIDATED FINANCIAL DATA

The following summary historical consolidated financial data as of December 31, 2011, 2010 and 2009 and for the years ended December 31, 2011, 2010 and 2009 is derived from our audited consolidated financial statements included in our Annual Report on Form 10-K and 10-K/A for the year ended December 31, 2011, which is incorporated by reference in this prospectus supplement. The following summary historical consolidated financial data as of September 30, 2012 and for the nine months ended September 30, 2012 and 2011 is derived from our unaudited interim financial statements included in our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2012, which is incorporated by reference in this prospectus supplement. The financial data as of and for the nine months ended September 30, 2012 and 2011 includes, in management's opinion, all adjustments necessary for the fair presentation of our financial position and results of operations as of such date and for such periods, but may not be indicative of results to be expected for the full year.

You should read the following data in connection with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements included in our Annual Report on Form 10-K and 10-K/A for the year ended December 31, 2011 and our Quarterly Report on Form 10-Q for the quarter ended September 30, 2012, where there is additional disclosure regarding the information in the following table.

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	Nine Months Ended September 30,		Year Ended December 31,		
	2012	2011	2011	2010(a)	2009
	(Unaudited)		(Dollars in thousands)		
Revenues:					
Oil sales	$ 212,097	$ 196,220	$ 264,473	$ 172,754	$ 103,319
Natural gas liquids (NGL) sales	10,742	13,896	18,888	13,670	11,565
Natural gas sales	33,166	39,858	53,524	29,965	22,395
Total revenues	256,005	249,974	336,885	216,389	137,279
Expenses:					
Oil and natural gas production	82,023	71,304	96,914	69,228	48,814
Production and other taxes	15,040	15,101	20,329	12,683	8,145
General and administrative	18,604	14,630	23,084	19,265	15,502
Depletion, depreciation, amortization and accretion	73,042	64,152	88,178	62,894	58,763
Impairment of long-lived assets	22,556	5,869	24,510	13,412	9,207
(Gain) loss on disposal of assets	(3,064)	(680)	(625)	592	378
Total expenses	208,201	170,376	252,390	178,074	140,809
Operating income (loss)	47,804	79,598	84,495	38,315	(3,530)
Other income (expense):					
Interest income	11	12	15	10	9
Interest expense	(14,256)	(15,633)	(18,566)	(25,766)	(13,222)
Equity in income of partnership	87	107	138	97	31
Realized and unrealized net gains (losses) on commodity derivatives	34,084	67,753	6,857	(1,400)	(75,554)
Other	(87)	(55)	152	90	(11)
Income (loss) before income taxes	67,643	131,782	73,091	11,346	(92,277)
Income tax expense	(878)	(1,198)	(1,030)	(537)	(554)
Net income (loss)	$ 66,765	$ 130,584	$ 72,061	$ 10,809	$ (92,831)
Income (loss) per unit basic and diluted	1.40	3.00	1.63	0.27	(2.89)
Weighted average number of units used in computing net income (loss) per unit					
Basic	47,840	43,560	44,093	40,233	32,163
Diluted	47,840	43,572	44,112	40,237	32,163
Cash Flow Data:					
Net cash provided by operating activities	$ 129,439	$ 144,172	$ 184,237	$ 101,371	$ 37,476
Net cash provided by (used in) investing activities	(162,916)	(154,706)	(206,816)	(285,246)	23,294
Net cash provided by (used in) financing activities	34,692	8,661	22,252	183,136	(59,053)

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	As of September 30, 2012	As of December 31, 2011	2010	2009
	(Unaudited)	(Dollars in Thousands)		
Balance Sheet Data:				
Cash and cash equivalents	$ 4,366	$ 3,151	$ 3,478	$ 4,217
Other current assets	62,654	56,634	47,120	45,394
Oil and natural gas properties, net of accumulated depletion, depreciation and amortization	1,041,759	959,329	843,836	575,425
Other assets	33,515	24,374	14,992	28,457
Total assets	$ 1,142,294	$ 1,043,488	$ 909,426	$ 653,493
Current liabilities	$ 98,264	97,450	72,955	54,226
Long term debt	452,000	337,000	325,000	237,000
Other long-term liabilities	115,050	120,703	119,732	83,607
Unitholders' equity	476,980	488,335	391,739	278,660
Total liabilities and unitholders' equity	$ 1,142,294	$ 1,043,488	$ 909,426	$ 653,493

	Nine Months Ended September 30, 2012	2011	Year Ended December 31, 2011	2010	2009
	(Unaudited)		(Dollars in thousands)		
Other Financial Data:					
Adjusted EBITDA(b)	$ 145,168	$ 148,257	$ 202,008	$ 140,407	$ 119,991
Distributable Cash Flow(c)	$ 78,944	$ 79,093	$ 108,459	$ 88,994	$ 88,040

(a) Reflects Legacy's purchase of the oil and natural gas properties (i) located in Wyoming from a third party for a net cash purchase price of $125.5 million on February 17, 2010 (the "Wyoming Acquisition"), and (ii) located primarily in the Permian Basin from COG Operating LLC, a wholly owned subsidiary of Concho Resources Inc., for a net cash purchase price of $100.8 million on December 22, 2010 (the "COG Acquisition") as of the closing dates of such acquisitions. Consequently, the operations of these acquired properties are only included for the period from the closing dates of such acquisitions through December 31, 2010 and thereafter.

(b) Adjusted EBITDA is defined in Legacy's revolving credit facility as net income (loss) plus:

- Interest expense;
- Income taxes;
- Depletion, depreciation, amortization and accretion;
- Impairment of long-lived assets;

(Gain) loss on sale of partnership investment;

(Gain) loss on disposal of assets (excluding settlements of asset retirement obligations);

Equity in (income) loss of partnership;

Unit-based compensation expense related to the Amended and Restated Legacy Reserves LP Long-Term Incentive Plan ("LTIP") unit awards accounted for under the equity or liability methods; and

Unrealized (gain) loss on oil and natural gas derivatives.

(c)

Distributable Cash Flow is defined as Adjusted EBITDA less:

Cash interest expense;

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- Cash income taxes;
- Cash settlements of LTIP unit awards; and
- Development capital expenditures.

Legacy's management uses Adjusted EBITDA and Distributable Cash Flow as tools to provide additional information and metrics relative to the performance of Legacy's business, such as the cash distributions Legacy expects to pay to its unitholders. Legacy's management believes that both Adjusted EBITDA and Distributable Cash Flow are useful to investors because these measures are used by many companies in the industry as measures of operating and financial performance and are commonly employed by financial analysts and others to evaluate the operating and financial performance of the Partnership from period to period and to compare it with the performance of other publicly traded partnerships within the industry. Adjusted EBITDA and Distributable Cash Flow may not be comparable to a similarly titled measure of other publicly traded limited partnerships or limited liability companies because all companies may not calculate Adjusted EBITDA in the same manner.

The following table presents a reconciliation of the non-GAAP financial measures of Adjusted EBITDA and Distributable Cash Flow to net income, which is the most directly comparable GAAP financial performance measure on a historical basis for each of the periods indicated.

	Nine Months Ended September 30,		Year Ended December 31,		
	2012	**2011**	**2011**	**2010**	**2009**
	(Unaudited)		**(Dollars in thousands)**		
Reconciliation of Adjusted EBITDA and Distributable Cash Flow to Net Income:					
Net income (loss)	$ 66,765	$ 130,584	$ 72,061	$ 10,809	$ (92,831)
Plus:					
Interest Expense	14,256	15,633	18,566	25,766	13,222
Income taxes	878	1,198	1,030	537	554
Depletion, depreciation, amortization and accretion	73,042	64,152	88,178	62,894	58,763
Impairment of long-lived assets	22,556	5,869	24,510	13,412	9,207
Gain on disposal of assets	(3,846)				(54)
Equity in income of partnership	(87)	(107)	(138)	(97)	(31)
Unit-based compensation expense	3,670	2,446	4,021	5,549	3,130
Unrealized (gain) loss on oil and natural gas derivatives	(32,066)	(71,518)	(6,220)	21,537	128,031
Adjusted EBITDA	145,168	148,257	202,008	140,407	119,991
Less:					
Cash Interest Expense	14,396	14,182	19,044	16,094	17,809
Cash settlements of LTIP unit awards	3,371	2,855	2,916	2,402	415
Development capital expenditures	48,457	52,127	71,589	32,917	13,727
Distributable Cash Flow	$ 78,944	$ 79,093	$ 108,459	$ 88,994	$ 88,040

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SUMMARY OPERATING DATA

The following table sets forth summary operating data for the periods indicated. You should read the following data in connection with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements included in our Annual Report on Form 10-K and 10-K/A for the year ended December 31, 2011 and our Quarterly Report on Form 10-Q for the quarter ended September 30, 2012, where there is additional disclosure regarding the information in the following table.

	Nine Months Ended September 30,		Year Ended December 31,		
	2012	2011	2011	2010(a)	2009
Production:					
Oil (MBbls)	2,418	2,190	2,951	2,334	1,800
Natural gas liquids (MGal)	10,938	10,509	14,559	12,890	15,118
Natural gas (MMcf)	7,774	6,397	8,842	5,204	5,055
Total (MBoe)	3,974	3,506	4,771	3,508	3,002
Average daily production (Boe/d)	14,504	12,842	13,071	9,611	8,225
Average sales price per unit (excluding derivatives):					
Oil price (per Bbl)	$ 87.72	$ 89.60	$ 89.62	$ 74.02	$ 57.40
Natural gas liquid price (per Gal)	$ 0.98	$ 1.32	$ 1.30	$ 1.06	$ 0.76
Natural gas price (per Mcf)	$ 4.27	$ 6.23	$ 6.05	$ 5.76	$ 4.43
Combined (per Boe)	$ 64.42	$ 71.30	$ 70.61	$ 61.68	$ 45.73
Average sales price per unit (including realized derivative gains/losses):					
Oil price (per Bbl)	$ 83.19	$ 84.19	$ 85.78	$ 77.99	$ 78.47
Natural gas liquid price (per Gal)	$ 0.98	$ 1.32	$ 1.30	$ 1.06	$ 0.81
Natural gas price (per Mcf)	$ 5.93	$ 7.49	$ 7.41	$ 7.86	$ 7.17
Combined (per Boe)	$ 64.93	$ 70.23	$ 70.74	$ 67.42	$ 63.21
NYMEX oil index prices per Bbl:					
Beginning of Period	$ 98.83	$ 91.38	$ 91.38	$ 79.36	$ 44.60
End of Period	$ 92.19	$ 79.20	$ 98.83	$ 91.38	$ 79.36
NYMEX gas index prices per Mcf:					
Beginning of Period	$ 2.99	$ 4.41	$ 4.41	$ 5.57	$ 5.62
End of Period	$ 3.32	$ 3.67	$ 2.99	$ 4.41	$ 5.57
Average unit costs per Boe:					
Production costs, excluding production and other taxes	$ 18.89	$ 18.42	$ 18.37	$ 17.97	$ 14.76
Ad valorem taxes	$ 1.75	$ 1.92	$ 1.95	$ 1.77	$ 1.50
Production and other taxes	$ 3.78	$ 4.31	$ 4.26	$ 3.62	$ 2.71
General and administrative	$ 4.68	$ 4.17	$ 4.84	$ 5.49	$ 5.16
Depletion, depreciation, amortization and accretion	$ 18.38	$ 18.30	$ 18.48	$ 17.93	$ 19.57

(a) Reflects the production and operating results of the oil and natural gas properties acquired in the Wyoming and COG acquisitions from the closing dates of such acquisitions (February 17, 2010 and December 22, 2010, respectively) through December 31, 2010 and thereafter.

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RISK FACTORS

An investment in our units involves risk. You should carefully read the following risk factors and the risk factors included under the caption "Risk Factors" beginning on page 3 of the accompanying prospectus, as well as the risk factors included in Item 1A. "Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2011, and our Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2012, June 30, 2012 and September 30, 2012, together with all of the other information included or incorporated by reference in this prospectus supplement. If any of these risks were to occur, our business, financial condition, results of operations or prospects could be materially adversely affected. In such case, the trading price of our units could decline, and you could lose all or part of your investment.

We may not be able to consummate our Pending Permian Basin Acquisition, which could adversely affect our business operations and cash available for distribution.

The purchase agreement related to the Pending Permian Basin Acquisition contains customary closing conditions. It is possible that one or more closing conditions may not be satisfied or, if not satisfied, that such condition may not be waived by the other party. The Pending Permian Basin Acquisition may also be subject to adjustment prior to closing, which could eliminate or reduce some of the properties we intend to acquire. If we were unable to consummate the Pending Permian Basin Acquisition or if the size of the acquisition is reduced, we would not realize the expected benefits of the proposed acquisition, including, without limitation, an expected increase in our distributable cash flow. If we are unable to successfully complete the Pending Permian Basin Acquisition, it could have a material adverse effect on our business, financial condition and results of operations.

Any acquisitions we complete, including the Pending Permian Basin Acquisition, are subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to make distributions to unitholders.

We may not achieve the expected results of the Pending Permian Basin Acquisition, and any adverse conditions or developments related to the Pending Permian Basin Acquisition may have a negative impact on our operations and financial condition.

Further, even if we complete acquisitions such as the Pending Permian Basin Acquisition, which we expect will increase distributable cash per unit, actual results may differ from our expectations and the impact of these acquisitions may actually result in a decrease in distributable cash per unit. Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues, capital expenditures and operating costs;
- an inability to successfully integrate the businesses we acquire;
- a decrease in our liquidity by using a portion of our available cash or borrowing capacity under our revolving credit facility to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown environmental and other liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns;
- the incurrence of other significant charges, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges;

unforeseen difficulities encountered in operating in new geographic areas; and

the loss of key purchasers of our production.

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Our decision to acquire oil and gas properties depends in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, seismic data and other information, the results of which are often inconclusive and subject to various interpretations.

Actual proved reserves of our 2012 acquisitions, including our Pending Permian Basin Acquisition, may prove to be lower than we have initially estimated.

This prospectus supplement contains our initial estimates of proved reserves of our 2012 acquisitions and our Pending Permian Basin Acquisition. These estimates were made by our internal engineering and professional staff based upon information furnished by the various sellers at the date of the respective acquisitions, or in the case of the Pending Permian Basin Acquisition, at September 30, 2012. Our estimates were based upon assumptions required by the Securities and Exchange Commission relating to oil and natural gas prices and costs in effect as of the date of acquisition, or in the case of the Pending Permian Basin Acquisition, at September 30, 2012. The process of estimating oil and natural gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise. As we acquire and own these properties over time, we will have more information to evaluate the reserves attributable to these acquisitions and our initial estimates may be revised accordingly. In addition, these estimates have largely not been reviewed by any independent engineering firm. Our independent engineers, in preparing our year-end 2012 reserve reports, may not agree with our initial estimates related to some of our acquired properties. Our estimates of first quarter 2013 production and anticipated contribution to cash flow from operations in 2013 for the Pending Permian Basin Acquisition included in this prospectus supplement are also highly dependent upon our internal reserve estimates.

Our 2012 acquisitions and our Pending Permian Basin Acquisition may prove to be worth less than we paid, or provide less than anticipated proved reserves, production or cash flow because of uncertainties in evaluating recoverable reserves, well performance, and potential liabilities as well as uncertainties in forecasting oil and gas prices and future development, production and marketing costs.

Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, development potential, well performance, future oil and natural gas prices, operating costs and potential environmental and other liabilities. Our estimates of future reserves and estimates of future production for our 2012 acquisitions, including the Pending Permian Basin Acquisition included herein, and related forecasts of anticipated cash flow therefrom, are initially based on detailed information furnished by the sellers and subject to review, analysis and adjustment by our internal staff, typically without consulting with outside petroleum engineers. Such assessments are inexact and their accuracy is inherently uncertain and our proved reserves estimates and cash flow forecasts therefrom may exceed actual acquired proved reserves or the estimates of future cash flows therefrom. In connection with our assessments, we perform a review of the acquired properties included in the 2012 acquisitions and the Pending Permian Basin Acquisition that we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. As a result of these factors, the purchase price we pay to acquire oil and natural gas properties may exceed the value we realize.

Also, our reviews of the properties included in the 2012 acquisitions and the Pending Permian Basin Acquisition are inherently incomplete because it is generally not feasible to perform an in-depth review of the individual properties involved in each acquisition given time constraints imposed by sellers. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

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USE OF PROCEEDS

We will receive net proceeds of approximately $206.8 million from the sale of 8,700,000 units offered by this prospectus supplement, after deducting underwriting discounts and commissions and estimated offering expenses payable by us. If the underwriters exercise their option to purchase additional units in full, we will receive additional net proceeds of approximately $31.1 million. We plan to use all of the net proceeds from this offering to fund a portion of the $520 million purchase price of the Pending Permian Basin Acquisition. Please read "Summary Recent Developments Pending Acquisition of Oil and Natural Gas Properties in the Permian Basin" for a description of the Pending Permian Basin Acquisition. Prior to funding the Pending Permian Basin Acquisition, we may use some or all of the net proceeds for general partnership purposes, which may include repayment of outstanding borrowings under our revolving credit facility.

We expect to fund the remaining portion of the purchase price for the Pending Permian Basin Acquisition with borrowings under our revolving credit facility or proceeds from the issuance of private or public debt securities, pending market conditions.

As of November 6, 2012, approximately $462.1 million of borrowings were outstanding under our revolving credit facility. As of November 6, 2012, interest on borrowings under our revolving credit facility had a weighted average effective interest rate of approximately 2.77%. The revolving credit facility matures on March 10, 2016. The proceeds of borrowings under our revolving credit facility are used primarily to finance acquisitions and for general partnership purposes, including the 2012 Acquisitions. Please read "Summary Recent Developments 2012 Acquisitions."

The closing of this offering is not contingent upon the closing of the Pending Permian Basin Acquisition. Accordingly, if you decide to purchase our units, you should be willing to do so whether or not we complete the Pending Permian Basin Acquisition. If we do not complete the Pending Permian Basin Acquisition, we will use the net proceeds from the offering to reduce borrowings outstanding under our revolving credit facility, for general partnership purposes and for potential future acquisitions.

The underwriters may, from time to time, engage in transactions with and perform services for us and our affiliates in the ordinary course of their business. Affiliates of Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., RBC Capital Markets, LLC and UBS Securities LLC are lenders under our revolving credit facility and may receive a portion of the proceeds from this offering through repayment of indebtedness under our revolving credit facility. Please read "Underwriting Conflicts of Interest."

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CAPITALIZATION

The following table shows our capitalization as of September 30, 2012 on an actual basis and as adjusted to reflect this offering of units, and the application of the net proceeds as described under "Use of Proceeds" assuming that such net proceeds are used to fund a portion of the purchase price for the Pending Permian Basin Acquisition.

You should read this information in conjunction with "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 1. Financial Statements" contained in our Quarterly Report on Form 10-Q for the three months ended September 30, 2012, which we incorporate by reference into this prospectus supplement.

	September 30, 2012	
	Actual	As Adjusted
	(In thousands)	
Cash and cash equivalents	$ 4,366	$ 5,196
Debt, including current maturities:		
Revolving credit facility	452,000(1)	246,000
Total debt	452,000	246,000
Owners' equity:		
Unitholders	476,883	683,713
General partner interest	97	97
Total unitholders' equity	$ 476,980	$ 683,810
Total capitalization	$ 928,980	$ 929,810

(1) As of November 6, 2012, approximately $462.1 million of borrowings were outstanding under our revolving credit facility. Pending the use of the net proceeds to fund a portion of the purchase price for the Pending Permian Basin Acquisition, we may use some or all of the net proceeds for general partnership purposes, which may include repayment of outstanding borrowings under our revolving credit facility.

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PRICE RANGE OF UNITS AND DISTRIBUTIONS

Our units are listed on the NASDAQ Global Select Market under the symbol "LGCY". The last reported sales price of the units on November 8, 2012 was $24.80. As of November 6, 2012, we had issued and outstanding 48,099,419 units, which were held by approximately 92 holders of record, including units held by our Founding Investors. The following table presents the high and low sales prices for our units during the periods indicated (as reported on the NASDAQ Global Select Market) and the amount of the quarterly cash distributions we paid on each of our units with respect to such periods:

	Price Ranges		Cash Distribution per Unit
	High	Low	
2012			
Fourth Quarter (through November 8, 2012)	$ 29.93	$ 24.80	$ (a)
Third Quarter	$ 29.40	$ 24.90	$ 0.565(b)
Second Quarter	$ 29.48	$ 23.16	$ 0.560
First Quarter	$ 30.07	$ 27.11	$ 0.555
2011			
Fourth Quarter	$ 30.85	$ 23.84	$ 0.550
Third Quarter	$ 30.85	$ 22.00	$ 0.545
Second Quarter	$ 33.71	$ 27.01	$ 0.540
First Quarter	$ 32.24	$ 27.84	$ 0.530
2010			
Fourth Quarter	$ 29.19	$ 24.66	$ 0.525
Third Quarter	$ 26.09	$ 21.25	$ 0.520
Second Quarter	$ 24.75	$ 17.86	$ 0.520
First Quarter	$ 23.22	$ 17.04	$ 0.520

(a) The distribution attributable to the quarter ending December 31, 2012 will be declared and paid within 45 days following the end of the quarter.

(b) On October 22, 2012, the board of directors of our general partner approved a quarterly distribution for the third quarter of 2012 of $0.565 per unit, or $2.26 on an annualized basis, which will be paid on November 14, 2012 to unitholders of record at the close of business on November 1, 2012. Purchasers of units in this offering will not be entitled to receive the distribution in respect of the third quarter of 2012.

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MATERIAL TAX CONSIDERATIONS

The tax consequences to you of an investment in our units will depend in part on your own tax circumstances. For a discussion of the principal U.S. federal income tax considerations associated with our operations and the purchase, ownership and disposition of our units, please read "Tax Risks to Unitholders" and "Material Tax Considerations" in the accompanying base prospectus. You are urged to consult with your own tax advisor about the federal, state, local and foreign tax consequences particular to your circumstances.

Partnership Tax Treatment

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for U.S. federal income tax purposes. We have not requested a ruling from the IRS with respect to our partnership status. In order to be treated as a partnership for U.S. federal income tax purposes, at least 90% or more of our gross income must be "qualifying income." Qualifying income includes income and gains derived from the exploration, development, mining or production, processing, transportation and marketing of natural resources, including natural gas, oil and products thereof. For a more complete description of this qualifying income requirement, please read "Material Tax Considerations Taxation of Legacy Reserves LP Partnership Status" in the accompanying base prospectus.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the limited partners, likely causing a substantial reduction in the value of our units.

Estimated Ratio of Taxable Income to Distributions

We estimate that if you purchase units in this offering and own them through the record date for the distribution with respect to the fourth calendar quarter of 2014, then you will be allocated, on a cumulative basis, an amount of U.S. federal taxable income for that period that will be less than 20% or less of the amount of cash distributed to you with respect to that period. If you continue to own units purchased in this offering after that period, the percentage of federal taxable income allocated to you may be higher. Our estimate is based upon many assumptions regarding our business and operations, including assumptions as to tariffs, capital expenditures, cash flows and anticipated cash distributions. Our estimate assumes that we will continue to distribute the current quarterly distribution throughout the referenced period. This estimate and the assumptions are subject to, among other things, numerous business, economic, regulatory, competitive and political uncertainties beyond our control. Further, this estimate is based on current tax law and certain tax reporting positions that we have adopted. Current tax law may change (see "Recent Legislative Developments" below) and the IRS could disagree with our tax reporting positions. Accordingly, we cannot assure you that the estimate will be correct. The actual percentage of taxable income to distributions could be higher or lower, and any differences could be material and could materially affect the value of units. For example, the ratio of taxable income to cash distributions to a purchaser of units in this offering will be greater, and perhaps substantially greater, than our estimate with respect to the period described above if:

- gross income from operations exceeds the amount required to make the current quarterly distribution on all units, yet we only distribute the current quarterly distribution on all units;

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- we drill fewer well locations than we anticipate or spend less than we anticipate in connection with our drilling and completion activities contemplated in our capital budget; or

- we make a future offering of units and use the proceeds of such offering in a manner that does not produce substantial additional deductions during the period described above, such as to repay indebtedness outstanding at the time of such offering or to acquire property that is not eligible for depletion, depreciation or amortization for U.S. federal income tax purposes or that is depletable, depreciable, or amortizable at a rate significantly slower than the rate applicable to our assets at the time of such offering.

Tax-Exempt Organizations & Other Investors

Ownership of units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. investors raises issues unique to such persons. Please read "Material Tax Considerations Tax-Exempt Organizations and Other Investors" in the accompanying base prospectus.

Recent Legislative Developments

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units, may be modified by administrative, legislative or judicial interpretation at any time. For example, the Obama Administration and members of Congress have considered and continue to consider substantive changes to the existing federal income tax laws that would affect the tax treatment of certain publicly traded partnerships. Currently, one such legislative proposal would eliminate the qualifying income exception upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether such changes, or other proposals, will ultimately be enacted. However, it is possible that a change in law could affect us and may be retroactively applied. Any such changes could negatively impact the value of an investment in our units.

Legislation has been proposed that would, if enacted, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our units.

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UNDERWRITING

Wells Fargo Securities, LLC, Barclays Capital Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets, Inc., J.P. Morgan Securities LLC, Raymond James & Associates, Inc., RBC Capital Markets, LLC and UBS Securities LLC are acting as joint book-running managers of the underwritten offering and representatives of the underwriters named below. Subject to the terms and conditions stated in the underwriting agreement dated the date of this prospectus supplement, each underwriter named below has agreed to purchase, and we have agreed to sell to that underwriter, the number of units set forth opposite the underwriter's name.

Underwriters	Number of Units
Wells Fargo Securities, LLC	1,044,000
Barclays Capital Inc.	957,000
Merrill Lynch, Pierce, Fenner & Smith Incorporated	957,000
Citigroup Global Markets Inc.	957,000
J.P. Morgan Securities LLC	957,000
Raymond James & Associates, Inc.	957,000
RBC Capital Markets, LLC	957,000
UBS Securities LLC	957,000
Robert W. Baird & Co. Incorporated	261,000
Stifel, Nicolaus & Company, Incorporated	261,000
Global Hunter Securities, LLC	108,750
Janney Montgomery Scott LLC	108,750
MLV & Co. LLC	108,750
Wunderlich Securities, Inc.	108,750
Total	8,700,000

The underwriting agreement provides that the obligations of the underwriters to purchase the units included in this offering are subject to approval of legal matters by counsel and to other conditions. The underwriters are obligated to purchase all of the units (other than those covered by the underwriters' option to purchase additional units described below) if they purchase any of the units.

Option to Purchase Additional Units

We have granted to the underwriters an option, exercisable for up to 30 days from the date of this prospectus supplement, to purchase up to 1,305,000 additional units at the public offering price less the underwriting discount. To the extent the option is exercised, each underwriter must purchase the number of additional units approximately proportionate to that underwriter's initial purchase commitment.

Underwriting Discount and Expenses

The underwriters propose to offer some of the units directly to the public at the public offering price set forth on the cover page of this prospectus supplement and some of the units to dealers at the public offering price less a concession not to exceed $0.595 per unit. If all of the units are not sold at the initial offering price, the underwriters may change the public offering price and the other selling terms. All compensation received by the underwriters in connection with this offering will not exceed 8% of the gross offering proceeds.

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The following table shows the underwriting discounts that we are to pay to the underwriters in connection with this offering. These amounts are shown assuming both no exercise and full exercise of the underwriters' option to purchase additional units.

	No Exercise	Full Exercise
Per Unit	$ 0.992	$ 0.992
Total	$ 8,630,400	$ 9,924,960

We estimate that our total expenses of this offering, excluding underwriting discounts, will be approximately $300,000.

Lock-Up Agreements

We, our general partner and the directors and executive officers of certain of our affiliates have agreed that during the 45 days after the date of this prospectus supplement, we and they will not, without the prior written consent of Wells Fargo Securities, LLC, directly or indirectly, offer for sale, contract to sell, sell, distribute, grant any option, right or warrant to purchase, pledge, hypothecate, enter into any derivative transaction with similar effect as a sale or otherwise dispose of any units, any securities convertible into, or exercisable or exchangeable for, units or any other rights to acquire such units within the time period of the lock-up, other than (1) pursuant to our long-term incentive plan, (2) in connection with acquisitions of assets or businesses in which units are issued as consideration, provided, however, any such recipient of units will agree to be bound by these provisions for the remainder of the 45-day period, or (3) pursuant to the underwriters' option to purchase additional units. Wells Fargo Securities, LLC may, in its sole discretion, allow any of these parties to offer for sale, contract to sell, sell, distribute, grant any option, right or warrant to purchase, pledge, hypothecate, enter into any derivative transaction with similar effect as a sale or otherwise dispose of any units, any securities convertible into, or exercisable or exchangeable for, units or any other rights to acquire such units prior to the expiration of such 45-day period in whole or in part at anytime without notice. Wells Fargo Securities, LLC has informed us that in the event that consent to a waiver of these restrictions is requested by us or any other person, Wells Fargo Securities, LLC, in deciding whether to grant its consent, will consider the unitholder's reasons for requesting the release, the number of units for which the release is being requested and market conditions at the time of the request for such release. However, Wells Fargo Securities, LLC has informed us that as of the date of this prospectus supplement there are no agreements between Wells Fargo Securities, LLC and any party that would allow such party to transfer any units, nor does it have any intention of releasing any of the units subject to the lock-up agreements prior to the expiration of the lock-up period at this time.

Listing

Our units are listed on the NASDAQ Global Select Market under the symbol "LGCY".

Passive Market Making

In connection with the offering, the underwriters may engage in passive market making transactions in the units on the NASDAQ Global Select Market in accordance with Rule 103 of Regulation M under the Securities Exchange Act of 1934 during the period before the commencement of offers or sales of units and extending through the completion of distribution. A passive market maker must display its bids at a price not in excess of the highest independent bid of the security. However, if all independent bids are lowered below the passive market maker's bid, that bid must be lowered when specified purchase limits are exceeded.

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Price Stabilization, Short Positions and Penalty Bids

In connection with the offering, the representatives, on behalf of the underwriters, may purchase and sell units in the open market. These transactions may include short sales, syndicate covering transactions and stabilizing transactions. Short sales involve syndicate sales of units in excess of the number of units to be purchased by the underwriters in the offering, which creates a syndicate short position. "Covered" short sales are sales of units made in an amount up to the number of units represented by the underwriters' over-allotment option. In determining the source of units to close out the covered syndicate short position, the underwriters will consider, among other things, the price of units available for purchase in the open market as compared to the price at which they may purchase units through the over-allotment option. Transactions to close out the covered syndicate short position involve either purchases of the units in the open market after the distribution has been completed or the exercise of the over-allotment option. The underwriters may also make "naked" short sales of units in excess of the over-allotment option. The underwriters must close out any naked short position by purchasing units in the open market. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the units in the open market after pricing that could adversely affect investors who purchase in the offering. Stabilizing transactions consist of bids for or purchases of units in the open market while the offering is in progress.

The underwriters also may impose a penalty bid. Penalty bids permit the underwriters to reclaim a selling concession from a syndicate member when the representatives repurchase units originally sold by that syndicate member in order to cover syndicate short positions or make stabilizing purchases.

Any of these activities may have the effect of preventing or retarding a decline in the market price of the units. They may also cause the price of the units to be higher than the price that would otherwise exist in the open market in the absence of these transactions. The underwriters may conduct these transactions on the NASDAQ Global Select Market or in the over-the-counter market, or otherwise. If the underwriters commence any of these transactions, they may discontinue them at any time.

Relationships With Underwriters

Some of the underwriters and their affiliates have performed investment and commercial banking and advisory services for us and our affiliates from time to time for which they have received customary fees and expenses. The underwriters and their affiliates may, from time to time in the future, engage in transactions with and perform services for us in the ordinary course of their business. In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers and may at any time hold long and short positions in such securities and instruments.

Conflicts of Interest

Affiliates of Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., RBC Capital Markets, LLC and UBS Securities LLC are lenders under our revolving credit facility and may receive a portion of the proceeds from this offering pursuant to the repayment of borrowings under that facility. Because the Financial Industry Regulatory Authority, or FINRA, views the units offered hereby as interests in a direct participation program, there is no conflict of interest between us and the underwriters under FINRA Rule 5121, and this offering is being made in compliance with FINRA Rule 5110. Investor suitability with respect to the units will be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

Electronic Distribution

This prospectus supplement and the accompanying prospectus in electronic format may be made available on the websites maintained by one or more of the underwriters. The underwriters may agree to allocate a number of units for sale to their online brokerage account holders. The units will be allocated to underwriters that may make Internet distributions on the same basis as other allocations. In addition, units may be sold by the underwriters to securities dealers who resell units to online brokerage account holders.

Other than this prospectus supplement and the accompanying prospectus in electronic format, information contained in any website maintained by an underwriter is not part of this prospectus supplement or the accompanying prospectus or registration statement of which the accompanying prospectus forms a part, has not been endorsed by us and should not be relied on by investors in deciding whether to purchase units. The underwriters are not responsible for information contained in websites that they do not maintain.

Indemnification

We have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act of 1933, as amended, or to contribute to payments the underwriters may be required to make because of any of those liabilities.

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LEGAL MATTERS

The validity of the units offered in this prospectus supplement will be passed upon for us by Andrews Kurth LLP, Houston, Texas. Certain legal matters in connection with the units offered hereby will be passed upon for the underwriters by Vinson & Elkins L.L.P., Houston, Texas.

Members of Vinson & Elkins L.L.P. involved in this offering beneficially own approximately 3,500 units representing limited partner interests in us.

EXPERTS

Information about our estimated net proved reserves and the future net cash flows attributable to the oil and natural gas reserves of Legacy Reserves LP as of December 31, 2011 contained in Legacy Reserves LP's annual report for the year ended December 31, 2011 filed on Form 10-K and included or incorporated herein by reference was prepared by LaRoche Petroleum Consultants, Ltd., an independent reserve engineer and geological firm, and is included or incorporated herein in reliance upon their authority as experts in reserves and present values.

The consolidated balance sheets of Legacy Reserves LP as of December 31, 2011 and 2010 and the related consolidated statements of operations, unitholders' equity, and cash flows for each of the years in the three year period ended December 31, 2011 of Legacy Reserves LP incorporated in this prospectus by reference from Legacy Reserves LP's annual report for the year ended December 31, 2011 filed on Form 10-K have been audited by BDO USA, LLP (formerly known as BDO Seidman, LLP), an independent registered public accounting firm, as stated in their report, which is incorporated herein by reference, and such financial statements have been so incorporated in reliance upon the report of such firm, given on the authority of said firm as experts in auditing and accounting.

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INCORPORATION BY REFERENCE

The SEC allows us to "incorporate by reference" the information we have filed with the SEC. This means that we can disclose important information to you without actually including the specific information in this prospectus supplement by referring you to other documents filed separately with the SEC. These other documents contain important information about us, our financial condition and results of operations. The information incorporated by reference is an important part of this prospectus supplement and the accompanying prospectus. Information that we file later with the SEC will automatically update and may replace information in this prospectus supplement, the accompanying prospectus and information previously filed with the SEC.

We are incorporating by reference into this prospectus supplement the documents listed below and any subsequent filings we make with the SEC under Sections 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934 (File no. 001-33249) (excluding information deemed to be furnished and not filed with the SEC) until all the units are sold:

We incorporate by reference into this prospectus supplement the documents listed below:

- Our Annual Reports on Form 10-K and 10-K/A for the year ended December 31, 2011;
- Our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2012, June 30, 2012 and September 30, 2012;
- Our Current Reports on Form 8-K filed January 13, 2012, January 31, 2012, February 7, 2012, March 1, 2012, March 7, 2012, April 25, 2012 (Form 8-K/A), May 15, 2012, September 11, 2012, and November 8, 2012; and
- The description of our units in our registration statement on Form 8-A filed January 10, 2007.

You may obtain any of the documents incorporated by reference in this prospectus supplement or the accompanying prospectus from the SEC through the SEC's website at *www.sec.gov*. You also may request a copy of any document incorporated by reference in this prospectus supplement and the accompanying prospectus (including exhibits to those documents specifically incorporated by reference in this document), at no cost, by visiting our internet website at *http://www.legacylp.com*, or by writing or calling us at the address set forth below. Information on our website is not incorporated into this prospectus supplement, the accompanying prospectus or our other securities filings and is not a part of this prospectus supplement or the accompanying prospectus.

Legacy Reserves LP
303 W. Wall St., Suite 1400
Midland, Texas 79701
Attention: Investor Relations
Telephone: (432) 689-5200

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FORWARD-LOOKING STATEMENTS

Some of the information included in this prospectus supplement and the documents we incorporate by reference herein contain "forward-looking" statements that are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about:

- our business strategy;
- the amount of oil and natural gas we produce;
- the price at which we are able to sell our oil and natural gas production;
- our ability to acquire additional oil and natural gas properties at economically attractive prices;
- our drilling locations and our ability to continue our development activities at economically attractive costs;
- the level of our lease operating expenses, general and administrative costs and finding and development costs, including payments to our general partner;
- the level of our capital expenditures;
- the level of cash distributions to our unitholders;
- our future operating results; and
- our plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this prospectus supplement and the documents we incorporate by reference herein, are forward-looking statements. In some cases, you can identify forward-looking statements by terminology such as "may", "could", "should", "expect", "plan", "project", "intend", "anticipate", "believe", "estimate", "predict", "potential", "pursue", "target", "continue", the negative of such terms or other comparable terminology.

These forward-looking statements are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on market conditions and other factors known at the time such statements are made. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements included in this prospectus supplement and the documents we incorporate by reference herein are not guarantees of future performance, and our expectations may not be realized or the forward-looking events and circumstances may not occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described under the caption "Risk Factors" in this prospectus supplement and in the accompanying prospectus, as well as the risk factors included in Item 1A. "Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2011, and our Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2012, June 30, 2012 and September 30, 2012. We disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly.

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PROSPECTUS

Legacy Reserves LP
Legacy Reserves Finance Corporation

Units Representing Limited Partner Interests
Debt Securities

We may offer, from time to time, in one or more series, the following securities under this prospectus:

- units representing limited partnership interests in Legacy Reserves LP; and
- debt securities, which may be secured or unsecured senior debt securities or secured or unsecured subordinated debt securities.

Legacy Reserve Finance Corporation may act as co-issuer of the debt securities. All other direct or indirect subsidiaries of Legacy Reserves LP, other than "minor subsidiaries" (except Legacy Reserves Finance Corporation) as such item is interpreted in securities regulations governing financial reporting for guarantors, may guarantee the debt securities.

Our units are listed on The NASDAQ Global Select Market, or NASDAQ, under the symbol "LGCY." We will provide information in a prospectus supplement, for the trading market, if any, for any debt securities we may offer.

We may offer and sell these securities to or through one or more underwriters, dealers and agents, or directly to purchasers, on a continuous or delayed basis. This prospectus describes some of the general terms that may apply to these securities and the general manner in which these securities may be offered. Specific terms of any securities to be offered and the specific manner in which we will offer such securities will be provided in one or more supplements to this prospectus. A prospectus supplement may also add, update, or change information contained in this prospectus.

You should carefully read this prospectus and any applicable prospectus supplement before you invest. You also should read the documents we have referred you to under the headings "Where You Can Find More Information" and "Incorporation By Reference" of this prospectus for information on us and our financial statements.

This prospectus may not be used to consummate sales of securities unless accompanied by a prospectus supplement.

Investing in our securities involves a high degree of risk. Limited partnerships are inherently different from corporations. For a discussion of the factors you should consider before deciding to purchase our securities, please see "Risk Factors" on page 3 of this prospectus, any risk factors contained in any applicable prospectus supplement, as well as any additional risk factors that may be contained in the documents incorporated by

reference herein and therein.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The date of this prospectus is September 6, 2011.

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In making your investment decision, you should rely only on the information contained in this prospectus, any prospectus supplement and the documents we have incorporated by reference. We have not authorized anyone to provide you with different information. We are not making an offer of these securities in any state where the offer is not permitted. You should not assume that the information contained in this prospectus or any prospectus supplement, as well as or that the information contained in any document incorporated by reference herein or therein, is accurate as of any date other than its respective date.

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ABOUT THIS PROSPECTUS

This prospectus is part of a registration statement on Form S-3 that we filed with the Securities and Exchange Commission, or SEC, utilizing a "shelf" registration process or continuous offering process for "well-known seasoned issuers." Under this shelf registration process, we may sell from time to time any combination of the securities described in this prospectus in one or more offerings.

This prospectus provides you with only a general description of the securities that we may offer. This prospectus does not contain all of the information set forth in the registration statement of which this prospectus is a part, as permitted by the rules and regulations of the SEC. Each time we offer securities, we will provide you with a prospectus supplement that will describe, among other things, the specific number, amounts and prices of the securities being offered, the specific manner in which they may be offered and the terms of the offering, including in the case of debt securities, the specific terms of the securities. The prospectus supplement may include additional risk factors or other special considerations applicable to those securities. The prospectus supplement may also add, update, or change information contained in this prospectus. If there is any inconsistency between the information in this prospectus and any prospectus supplement, you should rely on the information in the prospectus supplement.

The rules of the SEC allow us to incorporate by reference information into this prospectus and any prospectus supplement. Any information incorporated by reference is considered to be a part of this prospectus and any applicable prospectus supplement, and information that we file later with the SEC that is incorporated by reference herein will automatically update and supersede this information. Additional information, including our financial statements and the notes thereto, is incorporated in this prospectus by reference to our reports filed with the SEC. See "Where You Can Find More Information" and "Incorporation By Reference." In particular, you should carefully consider the risks and uncertainties described under the heading "Risk Factors" in this prospectus and those included in our periodic reports, which are all incorporated by reference in this prospectus, or otherwise included in any applicable prospectus supplement. Before investing in any of our securities, you are urged to carefully read this prospectus and any applicable prospectus supplement relating to the securities offered to you, together with the information and documents described under the headings "Where You Can Find More Information" and "Incorporation By Reference" of this prospectus and the information and documents incorporated by reference in the prospectus supplement.

References in this prospectus to "Legacy Reserves," "Legacy," "we," "our," "us," or like terms refer to Legacy Reserves LP and its subsidiaries unless the context otherwise requires.

CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING INFORMATION

This prospectus and the documents we incorporate by reference herein contain forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about:

- our business strategy;
- the amount of oil and natural gas we produce;
- the price at which we are able to sell our oil and natural gas production;
- our ability to acquire additional oil and natural gas properties at economically attractive prices;
- our drilling locations and our ability to continue our development activities at economically attractive costs;
- the level of our lease operating expenses, general and administrative costs and finding and development costs, including payments to our general partner;

the level of our capital expenditures;

the level of cash distributions to our unitholders;

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- our future operating results; and
- our plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this prospectus, are forward-looking statements. In some cases, you can identify forward-looking statements by terminology such as "may," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," the negative of such terms or other comparable terminology.

The forward-looking statements contained in this prospectus and any documents incorporated by reference are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this prospectus are not guarantees of future performance, and our expectations may not be realized or the forward-looking events and circumstances may not occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors set forth under the heading "Risk Factors" in this prospectus, in our filings with the SEC, including those factors described in our most recent annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K that are incorporated by reference into this prospectus, or those factors otherwise included in any applicable prospectus supplement. The forward-looking statements in this prospectus speak only as of the date of this prospectus; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to unduly rely on them.

ABOUT LEGACY RESERVES LP

We are an independent oil and natural gas limited partnership headquartered in Midland, Texas, and are focused on the acquisition and development of oil and natural gas properties primarily located in the Permian Basin, Mid-Continent and Rocky Mountain regions of the United States. We were formed in October 2005 to own and operate the oil and natural gas properties that we acquired from our founding investors ("Founding Investors") and three charitable foundations in connection with the closing of our private equity offering on March 15, 2006. On January 18, 2007, we completed our initial public offering.

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. Legacy Reserves Finance Corporation, our wholly owned subsidiary, has no material assets or any liabilities other than as a co-issuer of our debt securities. Its activities are limited to co-issuing our debt securities and activities incidental to its role as a co-issuer.

Our principal executive offices are located at 303 W. Wall Street, Suite 1400, Midland, Texas 79701 and our telephone number is (432) 689-5200.

THE SUBSIDIARY GUARANTORS

Certain of our subsidiaries may fully and unconditionally guarantee our payment obligations under any series of debt securities offered using this prospectus. Financial information concerning our subsidiary guarantors and any non-guarantor subsidiaries will, to the extent required by SEC rules and regulations, be included in our consolidated financial statements filed as part of our periodic reports pursuant to the Exchange Act.

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RISK FACTORS

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. Before you invest in our securities, you should carefully consider the following risk factors, those included in our most-recent annual report on Form 10-K, in our quarterly reports on Form 10-Q and in our current reports on Form 8-K that are incorporated herein by reference and those that may be included in the applicable prospectus supplement, together with all of the other information included in this prospectus, any prospectus supplement and the documents we incorporate by reference.

If any of these risks were actually to occur, our business, financial condition, results of operations, or cash flow could be materially adversely affected. In that case, our ability to make distributions to our unitholders or pay interest on, or the principal of, any debt securities, may be reduced, the trading price of our securities could decline and you could lose all or part of your investment.

Risks Related to our Business

We may not have sufficient available cash to pay the full amount of our current quarterly distribution or any distribution at all following establishment of cash reserves and payment of fees and expenses, including payments to our general partner.

We may not have sufficient available cash each quarter to pay the full amount of our current quarterly distribution or any distribution at all. The amount of cash we distribute in any quarter to our unitholders may fluctuate significantly from quarter to quarter and may be significantly less than our current quarterly distribution. Under the terms of our partnership agreement, the amount of cash otherwise available for distribution will be reduced by our operating expenses and the amount of any cash reserves that our general partner establishes to provide for future operations, future capital expenditures, future debt service requirements and future cash distributions to our unitholders. Further, our debt agreements contain restrictions on our ability to pay distributions. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of oil, NGL and natural gas we produce;
- the price at which we are able to sell our oil, NGL and natural gas production;
- the amount and timing of settlements on our commodity and interest rate derivatives;
- whether we are able to acquire additional oil and natural gas properties at economically attractive prices;
- whether we are able to continue our development projects at economically attractive costs;
- the level of our lease operating expenses, general and administrative costs and development costs, including payments to our general partner;
- the level of our interest expense, which depends on the amount of our indebtedness and the interest payable thereon; and
- the level of our capital expenditures.

If we are not able to acquire additional oil and natural gas reserves on economically acceptable terms, our reserves and production will decline, which would adversely affect our business, results of operations and financial condition and our ability to make cash distributions to our unitholders.

We may be unable to sustain distributions at the current level without making accretive acquisitions or substantial capital expenditures that maintain or grow our asset base. Oil and natural gas reserves are characterized by declining production rates, and our future oil and natural gas reserves and production and, therefore, our cash flow and our ability to make distributions are highly dependent on our success in economically finding or acquiring additional recoverable reserves and efficiently developing and exploiting our current reserves. Further, the rate of estimated decline of our oil and natural gas reserves may increase if our wells do not produce as expected. We may not be able to find, acquire or develop additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our future growth may be limited because we distribute all of our available cash to our unitholders, and potential future disruptions in the financial markets may prevent us from obtaining the financing necessary for growth and acquisitions.

Since we will distribute all of our available cash (as defined in our partnership agreement) to our unitholders, our growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations. Further, since we depend on financing provided by commercial banks and other lenders and the issuance of debt and equity securities to finance any significant growth or acquisitions, potential future disruptions in the global financial markets and any associated severe tightening of credit supply may prevent us from obtaining adequate financing from these sources, and, as a result, our ability to grow, both in terms of additional drilling and acquisitions, will be limited.

Increases in the cost of or failure of costs to adjust downward for drilling rigs, service rigs, pumping services and other costs in drilling and completing wells could reduce the viability of certain of our development projects.

Higher oil and natural gas prices may increase the rig count and thus the cost of rigs and oil field services necessary to implement our development projects while also decreasing their availability. Increased capital requirements for our projects will result in higher reserve replacement costs which could reduce cash available for distribution. Higher project costs could cause certain of our projects to become uneconomic and therefore not to be implemented, reducing our production and cash available for distribution. Decreased availability of drilling equipment and services could significantly impact the planned execution of our scheduled development program.

If commodity prices decline and remain depressed for a prolonged period, a significant portion of our development projects may become uneconomic and cause write downs of the value of our oil and gas properties, which may adversely affect our financial condition and our ability to make distributions to our unitholders.

Lower oil and natural gas prices may not only decrease our revenues, but also reduce the amount of oil and natural gas that we can produce economically. For example, the drastically lower oil and natural gas prices experienced in the fourth quarter of 2008 rendered more than half of the development projects we had planned at such time uneconomic and resulted in a substantial downward adjustment to our estimated proved reserves. Further, deteriorating commodity prices may cause us to recognize impairments in the value of our oil and gas properties. In addition, if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for impairments. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

Due to regional fluctuations in the actual prices received for our production, the derivative contracts we enter into may not provide us with sufficient protection against price volatility since they are based on indexes related to different and remote regional markets.

We sell our natural gas into local markets, the majority of which is produced in West Texas, Southeast New Mexico, the Texas Panhandle, Central Oklahoma and Wyoming and shipped to the Midwest, West Coast and Texas Gulf Coast. These regions account for over 90% of our natural gas sales. Our existing natural gas swaps are based on Waha, ANR-Oklahoma and CIG-Rockies directly. While we are paid a local price indexed to or closely related to Waha, ANR-Oklahoma and CIG-Rockies, these indexes are heavily influenced by prices received in remote regional consumer markets less transportation costs and thus may not be effective in protecting us against local price volatility.

Fluctuations in price and demand for our natural gas may force us to shut in a significant number of our producing wells, which may adversely impact our revenues and ability to pay distributions to our unitholders.

We are subject to great fluctuations in the prices we are paid for our natural gas due to a number of factors including regional demand, weather, demand for NGLs which are recovered from our gas stream, and new natural gas pipelines such as the REX pipeline from the Rocky Mountains to the Midwest which competes with our natural gas in the Midwest. Drilling in shale resources has developed large amounts of new natural gas supplies that have depressed the prices paid for our natural gas, and we expect the shale resources to continue to be drilled and developed by our competitors. We also face the potential risk of shut-in natural gas due to high levels of natural gas and NGL inventory in storage, weak demand due to mild weather and the effects of any economic downturns on industrial demand. Lack of NGL storage in Mont Belvieu where our West Texas and New Mexico NGLs are shipped for processing could cause the processors of our natural gas to curtail or shut-in our natural gas wells and potentially force us to shut-in oil wells that produce associated natural gas. For example, following Hurricanes Gustav and Ike, when certain Permian Basin natural gas processors were forced to shut down their plants due to the shutdown of the Texas Gulf Coast NGL fractionators, we were able to produce our oil wells and vent or flare the associated natural gas. There is no certainty we will be able to vent or flare natural gas again due to potential changes in regulations. Furthermore we may encounter problems in restarting production of previously shut-in wells.

Our commodity derivative activities may limit our ability to profit from price gains, could result in cash losses and expose us to counterparty risk and as a result could reduce our cash available for distributions.

We have entered into, and we may in the future enter into, oil and natural gas derivative contracts intended to offset the effects of commodity price volatility related to a significant portion of our oil and natural gas production. Many derivative instruments that we employ require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil and natural gas prices.

There is always substantial risk that counterparties in any derivative transaction cannot or will not perform under our derivative contracts. If a counterparty fails to perform and the derivative transaction is terminated, our cash flow and ability to pay distributions could be adversely impacted.

Further, if our actual production and sales for any period are less than our expected production covered by derivative contracts and sales for that period (including reductions in production due to involuntary shut-ins or operational delays) or if we are unable to perform our drilling activities as planned, we might be forced to satisfy all or a portion of our derivative contracts without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. Under our revolving credit facility, we are prohibited from entering into derivative contracts covering all of our production, and we therefore retain the risk of a price decrease on our volumes not covered by derivative contracts.

The substantial restrictions and financial covenants of our revolving credit facility, any negative redetermination of our borrowing base by our lenders and any potential disruptions of the financial markets could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We depend on our revolving credit facility for future capital needs. Our revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion.

Our revolving credit facility restricts, among other things, our ability to incur debt and pay distributions, and requires us to comply with certain financial covenants and ratios. We may not be able

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to comply with these restrictions and covenants in the future and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control, such as any potential disruptions in the financial markets. Our failure to comply with any of the restrictions and covenants under our revolving credit facility could result in a default under our revolving credit facility. A default under our revolving credit facility could cause all of our existing indebtedness to be immediately due and payable.

Outstanding borrowings in excess of the borrowing base must be repaid, and, if mortgaged properties represent less than 80% of total value of oil and gas properties used to determine the borrowing base, we must pledge other oil and natural gas properties as additional collateral. We may not have the financial resources in the future to make any mandatory principal prepayments required under our revolving credit facility.

The occurrence of an event of default or a negative redetermination of our borrowing base, such as a result of lower commodity prices or a deterioration in the condition of the financial markets, could adversely affect our business, results of operations, financial condition and our ability to make distributions to our unitholders.

Our estimated reserves are based on many assumptions that may prove inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

No one can measure underground accumulations of oil and natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves which could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Further, the present value of future net cash flows from our proved reserves may not be the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the 12-month average oil and gas index prices, calculated as the un-weighted arithmetic average for the first-day-of-the-month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the FASB in Accounting Standards Codification 932 may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

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

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

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Our development projects require substantial capital expenditures, which will reduce our cash available for distribution. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil and natural gas reserves.

We make and expect to continue to make substantial capital expenditures in our business for the development, production and acquisition of oil and natural gas reserves. These expenditures will reduce our cash available for distribution. We intend to finance our future capital expenditures with cash flow from operations and borrowings under our revolving credit facility. Our cash flow from operations and access to capital are subject to a number of variables, including:

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

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower oil and/or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. Our revolving credit facility restricts our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt or equity financing. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We do not control all of our operations and development projects and failure of an operator of wells in which we own partial interests to adequately perform could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Many of our business activities are conducted through joint operating agreements under which we own partial interests in oil and natural gas wells. If we do not operate wells in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The success and timing of our development projects on properties operated by others is outside of our control.

The failure of an operator of wells in which we own partial interests to adequately perform operations, or an operator's breach of the applicable agreements, could reduce our production and revenues and could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil and natural gas can be uneconomic, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable.

In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- the high cost, shortages or delivery delays of equipment and services;
- unexpected operational events;

adverse weather conditions;

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- facility or equipment malfunctions;
- title disputes;
- pipeline ruptures or spills;
- collapses of wellbore, casing or other tubulars;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- formations with abnormal pressures;
- fires;
- blowouts, craterings and explosions; and
- uncontrollable flows of oil, natural gas or well fluids.

Any of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties.

We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Increases in interest rates could adversely affect our business, results of operations, cash flows from operations and financial condition.

Since all of the indebtedness outstanding under our revolving credit facility is at variable interest rates, we have significant exposure to increases in interest rates. As a result, our business, results of operations and cash flows may be adversely affected by significant increases in interest rates. Further, an increase in interest rates may cause a corresponding decline in demand for equity investments, in particular for yield-based equity investments such as our units. Any reduction in demand for our units resulting from other more attractive investment opportunities may cause the trading price of our units to decline.

Any acquisitions we complete are subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to make distributions to unitholders.

We may not achieve the expected results of our acquisitions, and any adverse conditions or developments related to our acquisitions may have a negative impact on our operations and financial condition.

Further, even if we complete additional acquisitions, which we expect will increase pro forma distributable cash per unit, actual results may differ from our expectations and the impact of these acquisitions may actually result in a decrease in pro forma distributable cash per unit. Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues, capital expenditures and operating costs;
- an inability to successfully integrate the businesses we acquire;
- a decrease in our liquidity by using a portion of our available cash or borrowing capacity under our revolving credit facility to finance acquisitions;

- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns;
- the incurrence of other significant charges, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges;
- unforeseen difficulties encountered in operating in new geographic areas; and
- the loss of key purchasers.

Our decision to acquire a property depends in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, seismic data and other information, the results of which are often inconclusive and subject to various interpretations.

Also, our reviews of newly acquired properties are inherently incomplete because it is generally not feasible to perform an in-depth review of the individual properties involved in each acquisition given time constraints imposed by sellers. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. Our final determination on whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the numerous drilling locations we have identified will be drilled within our expected timeframe or will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may be materially different from those presently identified, which could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

The inability of one or more of our customers to meet their obligations may adversely affect our financial condition and results of operations.

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our oil and natural gas derivative transactions expose us to credit risk in the event of nonperformance by counterparties.

We depend on a limited number of key personnel who would be difficult to replace.

Our operations are dependent on the continued efforts of our executive officers, senior management and key employees. The loss of any member of our senior management or other key employees could negatively impact our ability to execute our strategy.

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We may be unable to compete effectively with larger companies, which could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources than us. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration and development activities during periods of low oil and natural gas market prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results could be harmed. We cannot be certain that our efforts to maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to continue to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet certain reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our units.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our oil and natural gas exploration and production operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. All such costs may have a negative effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil and natural gas exploration and production activities. These costs and liabilities could arise under a wide range of federal, state and local environmental and safety laws and regulations, including regulations and enforcement policies, which have tended to become increasingly strict over time. For example, the Environmental Protection Agency (the "EPA") recently proposed rules to restrict VOC emissions associated with oil and gas production. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations.

Strict, joint and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our ability to make cash distributions to our unitholders could be adversely affected.

Our sales of oil, natural gas, NGLs and other energy commodities, and related hedging activities, expose us to potential regulatory risks.

The Federal Trade Commission, the Federal Energy Regulatory Commission and the Commodity Futures Trading Commission hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil, natural gas, NGLs or other energy commodities, and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act") provides for new statutory and regulatory requirements for derivative transactions, including oil and gas hedging transactions. Certain transactions will be required to be cleared on exchanges and cash collateral will have to be posted. The Act provides for a potential exemption from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exemption applies to particular derivative transactions and the parties to those transactions. Since the Act mandates the Commodities Futures and Trading Commission (the "CFTC") to promulgate rules to define these terms, we do not know the definitions the CFTC will actually adopt or how these definitions will apply to us. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalent. Certain bona fide hedging transactions or positions would be exempt from these position limits. It is not possible at this time to predict if and when the CFTC will finalize these regulations.

Depending on the rules and definitions ultimately adopted by the CFTC, we might in the future be required to post cash collateral for our commodities derivative transactions. Posting of cash collateral could cause liquidity issues for us by reducing our ability to use our cash for capital expenditures or other partnership purposes. A requirement to post cash collateral could therefore reduce our ability to execute strategic hedges to reduce commodity price uncertainty and thus protect cash flows. Although the CFTC has issued proposed rules under the Act, we are at risk unless and until the CFTC adopts rules and definitions that confirm that companies such as us are not required to post cash collateral for our derivative hedging contracts. In addition, even if we are not required to post cash collateral for our derivative contracts, the banks and other derivatives dealers who are our contractual counterparties will be required to comply with the Act's new requirements, and the costs of their compliance will likely be

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passed on to customers, including us, thus decreasing the benefits to us of hedging transactions and reducing the profitability of our cash flows.

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

Congress is considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing is an important and commonly used process in the completion of unconventional natural gas wells in shale formations, as well as tight conventional formations including many of those that Legacy completes and produces. This process involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of these bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. In addition, some states have adopted and others are considering legislation to restrict hydraulic fracturing. Wyoming has adopted legislation requiring the disclosure of hydraulic fracturing chemicals. Texas recently adopted legislation which requires online disclosure of hydraulic fracturing chemicals beginning in July 2012. In response, the Railroad Commission of Texas recently proposed new rules requiring certain disclosure rules. Other federal agencies are investigating hydraulic fracturing practices legislation that requires the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition any additional level of regulation could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

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

On December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. On January 2, 2011 regulations that require a reduction in emissions of greenhouse gases from motor vehicles became effective. The EPA has determined that such regulations trigger permit review for greenhouse gas emissions from certain stationary sources. EPA adopted a tiered approach to implementing the permitting of GHG emissions from stationary sources under the PSD and Title V permitting programs in May 2010. The so-called "tailoring rule" only requires the stationary sources with the largest emissions to undergo an assessment of GHG emissions under the best available control technology or "BACT" under the federal permitting programs. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA published mandatory reporting rules for oil and gas systems requiring reporting starting in 2012 for emissions in 2011. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the oil, natural gas and NGL that we produce.

Legislation has been considered at the state and federal level. Any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the oil, natural gas and NGLs that we produce.

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Units eligible for future sale may have adverse effects on our unit price and the liquidity of the market for our units.

We cannot predict the effect of future sales of our units, or the availability of units for future sales, on the market price of or the liquidity of the market for our units. Sales of substantial amounts of units, or the perception that such sales could occur, could adversely affect the prevailing market price of our units. Such sales, or the possibility of such sales, could also make it difficult for us to sell equity securities in the future at a time and at a price that we deem appropriate. As of September 6, 2011, the Founding Investors and their affiliates, including members of our management, owned approximately 23% of our outstanding units. We granted the Founding Investors certain registration rights to have their units registered under the Securities Act. Upon registration, these units will be eligible for sale into the market. Because of the substantial size of the Founding Investors' holdings, the sale of a significant portion of these units, or a perception in the market that such a sale is likely, could have a significant impact on the market price of our units.

Risks Related to Our Limited Partnership Structure

Our Founding Investors, including members of our management, own an approximate 23% limited partner interest in us and control our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner has conflicts of interest and limited fiduciary duties, which may permit it to favor its own interests to the detriment of our unitholders.

Our Founding Investors, including members of our management, as of September 6, 2011 owned an approximate 23% limited partner interest in us and therefore have the ability to exercise a significant amount of control over the election of the entire board of directors of our general partner. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owners, our Founding Investors and their affiliates. Conflicts of interest may arise between our Founding Investors and their affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires our Founding Investors or their affiliates, other than our executive officers, to pursue a business strategy that favors us;

- our general partner is allowed to take into account the interests of parties other than us, such as our Founding Investors, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;

- our Founding Investors and their affiliates (other than our executive officers and their affiliates) may engage in competition with us;

- our general partner has limited its liability and reduced its fiduciary duties under our partnership agreement and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty. As a result of purchasing units, unitholders consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law;

- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership securities, and reserves, each of which can affect the amount of cash that is distributed to our unitholders;

- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or a growth capital expenditure, which does not reduce operating surplus. Such determination can affect the amount of cash that is distributed to our unitholders;

- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;

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- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

- our general partner intends to limit its liability regarding our contractual and other obligations;

- our general partner controls the enforcement of obligations owed to us by it and its affiliates; and

- our general partner decides whether to retain separate counsel, accountants, or others to perform services for us.

Our partnership agreement restricts the voting rights of those unitholders owning 20% or more of our units.

Unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Our Founding Investors and their affiliates (other than our executive officers and their affiliates) may compete directly with us.

Our Founding Investors and their affiliates, other than our general partner and our executive officers and their affiliates, are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, our Founding Investors or their affiliates, other than our general partner and our executive officers and their affiliates, may acquire, develop and operate oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to acquire, develop or operate those assets.

Cost reimbursements due our general partner and its affiliates will reduce our cash available for distribution to our unitholders.

Prior to making any distribution on our outstanding units, we will reimburse our general partner and its affiliates for all expenses they incur on our behalf. Any such reimbursement will be determined by our general partner in its sole discretion. These expenses will include all costs incurred by our general partner and its affiliates in managing and operating us. The reimbursement of expenses of our general partner and its affiliates could adversely affect our ability to pay cash distributions to our unitholders.

Our partnership agreement limits our general partner's fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any unitholder;

- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;

- provides that our general partner is entitled to make other decisions in "good faith" if it believes that the decision is in our best interest;

- provides generally that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us, as determined by our general partner in good faith, and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and

- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our unitholders or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct.

Our partnership agreement permits our general partner to redeem any partnership interests held by a limited partner who is a non-citizen assignee.

If we are or become subject to federal, state or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner, our general partner may redeem the units held by the limited partner at their current market price. In order to avoid any cancellation or forfeiture, our general partner may require each limited partner to furnish information about his nationality, citizenship or related status. If a limited partner fails to furnish information about his nationality, citizenship or other related status within 30 days after a request for the information or our general partner determines after receipt of the information that the limited partner is not an eligible citizen, our general partner may elect to treat the limited partner as a non-citizen assignee. A non-citizen assignee is entitled to an interest equivalent to that of a limited partner for the right to share in allocations and distributions from us, including liquidating distributions. A non-citizen assignee does not have the right to direct the voting of his units and may not receive distributions in kind upon our liquidation.

We may issue an unlimited number of additional units without the approval of our unitholders, which would dilute their existing ownership interest in us.

Our general partner, without the approval of our unitholders, may cause us to issue an unlimited number of additional units. The issuance by us of additional units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interests in us will decrease;

- the amount of cash available for distribution on each unit may decrease;

- the risk that a shortfall in the payment of our current quarterly distribution will increase;

- the relative voting strength of each previously outstanding unit may be diminished; and

- the market price of the units may decline.

The liability of our unitholders may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. In some states, including Delaware, a limited partner is only liable if he participates in the "control" of the business of the partnership. These statutes generally do not define control, but do permit limited partners to engage in certain activities, including, among other actions, taking any action with respect to the dissolution of the partnership, the sale, exchange, lease or mortgage of any asset of the partnership, the admission or removal of the general partner and the amendment of the partnership agreement. Our unitholders could, however, be liable for any and all of our obligations as if our unitholders were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or

- our unitholders' right to act with other unitholders to take other actions under our partnership agreement constitutes "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the distribution, limited partners who received an impermissible distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to such substitute limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of additional entity-level taxation by states and localities. If the IRS were to treat us as a corporation or if we were to become subject to a material amount of additional entity-level taxation for state or local tax purposes, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which currently has a top marginal rate of 35%, and would likely pay state and local income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available to pay distributions to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders likely causing a substantial reduction in the value of our units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are subject to an entity-level state tax on the portion of our gross income that is apportioned to Texas. If any additional states were to impose a tax upon us as an entity, the cash available for distribution to our unitholders would be reduced.

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The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, or Qualifying Income Exception, affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our units. Recently, members of Congress have considered substantive legislative changes to existing U.S. tax laws that would affect publicly traded partnerships.

We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our units.

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

President Obama's Proposed Fiscal Year 2012 Budget includes proposals that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production actifont-size:10pt;"> .

Note 5. Income Per Share

The following table sets forth the computation of basic and diluted income per share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Numerator:				
Net income	$7,866	$10,903	$8,461	$11,720
Denominator:				
Denominator for basic income per share - Weighted-average shares	92,351	91,808	92,323	91,775
Effect of dilutive securities:				
Stock options and restricted stock	1,010	1,455	988	1,673
Denominator for diluted income per share - Weighted-average shares and assumed conversions	93,361	93,263	93,311	93,448
Net income per common share – basic	$0.09	$0.12	$0.09	$0.13
Net income per common share – diluted	$0.08	$0.12	$0.09	$0.13

Note 6. Hedging Program and Derivatives

The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. Management has elected not to apply hedge accounting as prescribed by ASC 815. Accordingly, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period.

The following table sets forth our derivative contracts at June 30, 2013:

Contract Periods	Fixed Price Swap Oil – WTI Daily Volume (Bbl)	Swap Price (per Bbl)	Oil - Brent Daily Volume (Bbl)	Swap Price (per Bbl)
2013	1,007	$84.76	510	$105.00
2014	687	$94.16	505	$100.56
2015	560	$83.03	500	$97.04
2016	963	$84.10	—	$—
2017	500	$84.18	—	$—

At June 30, 2013, the aggregate fair value of our commodity derivative contracts was an asset of approximately $0.4 million.

The following table illustrates the impact of derivative contracts on the Company's balance sheet:

Fair Value of Derivative Instruments as of June 30, 2013

	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity price derivatives	Derivatives – current	$1,170	Derivatives – current	$2,532
Commodity price derivatives	Derivatives - long-term	2,317	Derivatives - long-term	510
		$3,487		$3,042

Fair Value of Derivative Instruments as of December 31, 2012

	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity price derivatives	Derivatives – current	$41	Derivatives – current	$3,462
Commodity price derivatives	Derivatives – long-term	594	Derivatives – long-term	3,568
		$635		$7,030

Gains and losses from derivative activities are reflected as "(Gain) loss on derivative contracts" in the accompanying condensed consolidated statements of operations.

Note 7. Fair Value

Fair Value Hierarchy—ASC 820-10 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1 – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2 – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

• Level 3 - inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Company is further required to assess the creditworthiness of the counter-party to the derivative contract. The results of the assessment of nonperformance risk, based on the counter-party's credit risk, could result in an adjustment of the carrying value of the derivative instrument. The following tables set forth information about the Company's assets and liabilities measured at fair value on a recurring basis as of June 30, 2013 and December 31, 2012, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of June 30, 2013
Assets:				
Investment in common stock	$128	$—	$—	$128
NYMEX Fixed Price Derivative contracts	—	3,487	—	3,487
Total Assets	$128	$3,487	$—	$3,615
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$3,042	$—	$3,042
Total Liabilities	$—	$3,042	$—	$3,042

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2012
Assets:				
Investment in common stock	$78	$—	$—	$78
NYMEX Fixed Price Derivative contracts	—	635	—	635
Total Assets	$78	$635	$—	$713
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$7,030	$—	$7,030
Total Liabilities	$—	$7,030	$—	$7,030

The Company has an investment in Insignia Energy Ltd, the surviving entity in the merger with a former subsidiary, consisting of shares of common stock. The stock is actively traded on the Toronto Stock Exchange. This investment is valued at its quoted price as of June 30, 2013 and December 31, 2012 in U.S. dollars. Accordingly, this investment is characterized as Level 1. On May 6, 2013, Insignia Energy Ltd, announced plans to privatize the company whereby all shareholders will receive C$1.35 per share. On July 19, 2013 Insignia announced that it had completed the plan. The Company has submitted its shares for the cash consideration.

The Company's derivative contracts consist of NYMEX-based fixed price commodity swaps and Brent-based fixed price commodity swaps. The NYMEX-based and Brent based fixed price derivative contracts are indexed to their respective futures contracts, which are actively traded for the underlying commodity and commonly used in the energy industry. As the fair value of these derivative contracts is based on a number of inputs, including contractual volumes and prices stated in each derivative contract, current and future NYMEX commodity prices, and quantitative models that are based upon readily observable market parameters that are actively quoted and can be validated through external sources, we have characterized these derivative contracts as Level 2.

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Other Financial Instruments

The carrying amounts of our cash, cash equivalents, restricted cash, accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. The carrying value of our debt approximates fair value as the interest rates are market rates and this debt is considered Level 2.

Note 8. Business Segments

The following tables provide the Company's geographic operating segment data for the three and six months ended June 30, 2013 and 2012:

	Three Months Ended June 30, 2013			
	U.S.	Canada	Corporate	Total
Revenues:				
Oil and gas production	$20,946	$532	$—	$21,478
Other	—	—	16	16
	20,946	532	16	21,494
Expenses:				
Lease operating	5,783	383	—	6,166
Production taxes	1,906	5	—	1,911
Depreciation, depletion and amortization	5,411	302	63	5,776
Impairment	—	1,977	—	1,977
General and administrative	486	186	2,125	2,797
Net interest	157	5	1,097	1,259
Amortization of deferred financing fees	—	—	343	343
Loss on derivative contracts - Realized	—	—	783	783
(Gain) on derivative contracts - Unrealized	—	—	(7,485)	(7,485)
Other	—	—	14	14
Income tax	—	—	87	87
Net income (loss)	$7,203	$(2,326)	$2,989	$7,866

	Three Months Ended June 30, 2012			
	U.S.	Canada	Corporate	Total
Revenues:				
Oil and gas production	$15,112	$822	$—	$15,934
Other	—	—	4	4
	15,112	822	4	15,938
Expenses (income):				
Lease operating	5,041	341	—	5,382
Production taxes	1,489	—	—	1,489
Depreciation, depletion and amortization	4,896	421	63	5,380
Impairment	—	1,306	—	1,306
General and administrative	377	174	1,853	2,404
Net interest	115	4	1,150	1,269
Amortization of deferred financing fees	—	—	266	266
Earnings from equity method investment	—	—	(1,251)	(1,251)
(Gain) on derivative contracts - Realized	—	—	(914)	(914)
(Gain) on derivative contracts - Unrealized	—	—	(10,296)	(10,296)
Other	—	—	—	—
Net income (loss)	$3,194	$(1,424)	$9,133	$10,903

	Six Months Ended June 30, 2013			
	U.S.	Canada	Corporate	Total
Revenues:				
Oil and gas production	$41,504	$1,137	$—	$42,641
Other	—	—	49	49
	41,504	1,137	49	42,690
Expenses:				
Lease operating	11,587	1,041	—	12,628
Production taxes	3,833	5	—	3,838
Depreciation, depletion and amortization	11,625	535	125	12,285
Impairment	—	1,977	—	1,977
General and administrative	961	341	4,025	5,327
Net interest	323	11	2,132	2,466
Amortization of deferred financing fees	—	—	676	676
Loss on derivative contracts - Realized	—	—	1,708	1,708
(Gain) on derivative contracts - Unrealized	—	—	(6,864)	(6,864)
Other	—	—	101	101
Income tax	—	—	87	87
Net income (loss)	$13,175	$(2,773)	$(1,941)	$8,461

	Six Months Ended June 30, 2012			
	U.S.	Canada	Corporate	Total
Revenues:				
Oil and gas production	$30,987	$1,326	$—	$32,313
Other	—	—	18	18
	30,987	1,326	18	32,331
Expenses:				
Lease operating	10,750	566	—	11,316
Production taxes	2,985	—	—	2,985
Depreciation, depletion and amortization	9,454	639	125	10,218
Impairment	—	1,306	—	1,306
General and administrative	703	295	3,307	4,305
Net interest	227	8	2,228	2,463
Amortization of deferred financing fees	—	—	296	296
Earnings from equity method investment	—	—	(2,034)	(2,034)
(Gain) on derivative contracts - Realized	—	—	(866)	(866)
(Gain) on derivative contracts - Unrealized	—	—	(9,420)	(9,420)
Other	—	—	42	42
Net income (loss)	$6,868	$(1,488)	$6,340	$11,720

The following table provides the Company’s geographic asset data as of June 30, 2013 and December 31, 2012:

Segment Assets:	June 30, 2013	December 31, 2012
United States	$206,900	$223,253
Canada	5,888	7,053
Corporate	47,305	10,301
	$260,093	$240,607

Note 9. Contingencies – Litigation

From time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. At June 30, 2013, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on its operations.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is a discussion of our financial condition, results of operations, liquidity and capital resources. This discussion should be read in conjunction with our consolidated financial statements and the notes thereto, included in our Annual Report on Form 10-K for the year ended December 31, 2012 filed with the SEC on March 18, 2013.

The results of operations set forth below do not include our interest in the operations of Blue Eagle which was dissolved effective August 31, 2012.

Except as otherwise noted, all tabular amounts are in thousands except per unit values.

Critical Accounting Policies

There have been no changes from the Critical Accounting Policies described in our Annual Report on Form 10-K for the year ended December 31, 2012.

General

We are an independent energy company primarily engaged in the acquisition, exploration, exploitation, development and production of oil and gas in the United States and Canada. Historically, we have grown through the acquisition and subsequent development and exploitation of producing properties, principally through the redevelopment of old fields utilizing new technologies such as modern log analysis and reservoir modeling techniques as well as 3-D seismic surveys and horizontal drilling. As a result of these activities, we believe that we have a number of development opportunities on our properties. In addition, we intend to expand upon our development activities with complementary exploration projects in our core areas of operation. Success in our development and exploration activities is critical in the maintenance and growth of our current production levels and associated reserves.

Factors Affecting Our Financial Results

While we have attained positive net income in two of the last five years, there can be no assurance that operating income and net earnings will be achieved in future periods. Our financial results depend upon many factors which significantly affect our results of operations including the following:

- commodity prices and the effectiveness of our hedging arrangements;
- the level of total sales volumes of oil and gas;
- the availability of and our ability to raise additional capital resources and provide liquidity to meet cash flow needs;
- the level of and interest rates on borrowings; and
- the level and success of exploration and development activity

Commodity Prices and Hedging Activities

The results of our operations are highly dependent upon the prices received for our production. The prices we receive are dependent upon spot market prices, differentials and the effectiveness of our derivative contracts, which we sometimes refer to as hedging arrangements. Substantially all of our sales are made in the spot market, or pursuant to contracts based on spot market prices, and not pursuant to long-term, fixed-price contracts. Accordingly, the prices received for our production are dependent upon numerous factors beyond our control. Significant declines in commodity prices could have a material adverse effect on our financial condition, results of operations, cash flows and quantities of reserves recoverable on an economic basis.

During the six months ended June 30, 2013, the New York Mercantile (NYMEX) future price for oil averaged $94.26 per barrel as compared to $98.13 per barrel during the six months ended June 30, 2012. NYMEX future spot prices for gas averaged $3.76 per MMBtu for the six months ended June 30, 2013 compared to $2.36 for the same period of 2012. Prices closed on June 30, 2013 at $96.56 per Bbl of oil and $3.57 per MMBtu of gas, compared to closing on June 30, 2012 at $84.96 per Bbl of oil and $2.74 per MMBtu of gas. The realized prices that we receive for our production differ from NYMEX futures and spot market prices, principally due to:

- basis differentials which are dependent on actual delivery location;

- adjustments for BTU content;
- quality of the hydrocarbons; and
- gathering; processing and transportation costs.

The following table sets forth our average differentials for the six months ended June 30, 2013 and 2012:

	Oil - NYMEX		Gas - NYMEX	
	2013	2012	2013	2012
Average realized price (1)	$90.61	$86.36	$3.26	$2.02
Average NYMEX price	$94.26	$98.13	$3.76	$2.36
Differential	$(3.65)	$(11.77)	$(0.50)	$(0.34)

(1) excludes the impact of derivative activities

Increases in the differential between the NYMEX price and the realized price we receive have in the past, and could in the future, significantly reduce our revenues and cash flow from operations. The increase in the gas differential was primarily due to gas produced in the Eagle Ford which has a higher differential due to the quality of the gas.

Our results of operations are significantly affected by fluctuations in commodity prices and we seek to reduce our exposure to price volatility by hedging our production through swaps, options and other commodity derivative instruments. By removing a significant portion of price volatility on our future production, we believe we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations for those periods. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow on the portion of the production that has been hedged. We have sustained and, in the future, will sustain realized and unrealized losses on our derivative contracts when market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will recognize realized and unrealized gains on our commodity derivative contracts. In the six months ended June 30, 2013, we recognized a realized loss of $1.7 million and an unrealized gain of $6.9 million on our commodity swaps. In the six months ended June 30, 2012, we recognized a realized gain of $2.0 million and an unrealized gain of $8.5 million on our commodity swaps. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

The following table sets forth our derivative contracts at June 30, 2013:

	Fixed Price Swap			
	Oil – WTI		Oil - Brent	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (Bbl)	Swap Price (per Bbl)
2013	1,007	$84.76	510	$105.00
2014	687	$94.16	505	$100.56
2015	560	$83.03	500	$97.04
2016	963	$84.10	—	$—
2017	500	$84.18	—	$—

At June 30, 2013, the aggregate fair value of our oil and gas derivative contracts was an asset of approximately $0.4 million.

Production Volumes

Our proved reserves will decline as oil and gas are produced, unless we find, acquire or develop additional properties containing Proved reserves or conduct successful exploration and development activities in a timely manner. Based on the reserve information set forth in our reserve estimates as of December 31, 2012, the average annual estimated decline rate for our net proved developed producing reserves is 13% during the first five years, 8% in the next five years, and approximately 7% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and prior property sales. Our ability to acquire or find additional reserves will be dependent, in part, upon the amount of available funds for acquisition, exploration and development projects.

We had capital expenditures of $33.5 million during the six months ended June 30, 2013. We have a capital expenditure budget for 2013 of $70.0 million. Approximately 68% of the 2013 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks in the Rocky Mountain region, approximately 27% in the Eagle Ford Shale play in South Texas with the remainder targeting conventional oil plays in the Permian Basin region and in the province of Alberta, Canada. The 2013 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, the results of our exploitation efforts, and our ability to obtain permits for drilling locations.

Availability of Capital

As described more fully under "Liquidity and Capital Resources" below, our sources of capital are cash flow from operating activities, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, and if an appropriate opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financing on terms acceptable to us, if at all. As of June 30, 2013, we had $34.0 million of availability under our credit facility.

Exploration and Development Activity

We believe that our high quality asset base, high degree of operational control and inventory of drilling projects position us for future growth. At December 31, 2012, we operated properties accounting for approximately 81% of our PV-10, giving us substantial control over the timing and incurrence of operating and capital expenditures. We have identified numerous additional drilling locations on our existing leaseholds, the successful development of which we believe could significantly increase our production and proved reserves. Over the five years ended December 31, 2012, we drilled or participated in 146 gross (41.29 net) wells, of which 99% were commercially productive.

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves. We cannot assure you that our exploration and development activities will result in increases in our proved reserves. If our proved reserves decline in the future, our production may also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility may also decline. In addition, approximately 49% of our estimated proved reserves at December 31, 2012 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. We may be unable to acquire or develop additional reserves, in which case our results of operations and financial condition could be adversely affected.

Operational Update

Williston Basin

In McKenzie County, North Dakota, the Lillibridge 1H, 2H and 3H have all been flowing to sales at rates significantly above the Company's type curve. The Lillibridge 1H, producing from the Middle Bakken, is currently producing 1,442 Boepd (1,165 barrels of oil per day, 1,662 Mcf of natural gas per day) on a 16/64" choke. Cumulative production from the Lillibridge 1H is 18,423 Boe (14,920 barrels of oil, 21,018 Mcf of natural gas) over its first 16 full production days on a restricted choke. The Lillibridge 2H, producing from the Three Forks, is currently producing 1,170 Boepd (943 barrels of oil per day, 1,364 Mcf of natural gas per day) on a 18/64" choke. Cumulative production from the Lillibridge 2H is 15,866 Boe (12,761 barrels of oil, 18,630 Mcf of natural gas) over its first 16 full production days on a restricted choke. The Lillibridge 3H, producing from the Middle Bakken, is currently producing 1,794 Boepd (1,428 barrels of oil per day, 2,195 Mcf of natural gas per day) on a 12/64" choke. Cumulative production from the Lillibridge 3H is 14,158 Boe (11,233 barrels of oil, 17,547 Mcf of natural gas) over its first 11 full production days on a restricted choke. The production rates for each well do not include the impact of natural gas liquids and shrinkage at the processing plant. The Lillibridge 4H is currently shut in awaiting cleanout due to what is believed to be a sand plug. Post cleaning out the well with coil tubing Abraxas will provide its flow rate. Each of the three producing Lillibridge wells was constrained on a smaller than normal choke to manage midstream gas takeaway bottlenecks, which are being remedied.

On the Lillibridge West pad, Abraxas recently set intermediate casing on the Lillibridge 7H and is currently drilling the final intermediate section on the Lillibridge 8H. After reaching TD on the intermediate section for the 8H, Abraxas will commence the drilling of all four laterals. Abraxas owns a working interest of approximately 34% in both the Lillibridge East and West pads.

Eagle Ford Shale

In McMullen County, Texas, Abraxas' forty acre pilot wells, the Camaro B 3H and Camaro B 4H, have been successfully completed with 39 stages across the two wells. Post the drilling out of plugs, the wells will be turned over to sales. The Company is currently prepping the Gran Torino A 11H for a 19 stage completion. Abraxas' thirteenth well at the WyCross prospect, the Sting Ray A 8H is currently drilling below 4,500 feet. Abraxas owns an 18.75% working interest in the Sting Ray A 8H and Gran Torino A 11H and a 25% working interest in the Camaro B 3H and Camaro B 4H.

Results of Operations

The following table sets forth certain of our consolidated operating data for the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Operating revenue: (1)				
Oil sales	$17,261	$12,897	$34,445	$26,289
Gas sales	3,137	1,943	5,989	4,005
NGL sales	1,080	1,094	2,207	2,019
Other	16	4	49	18
	$21,494	$15,938	$42,690	$32,331
Operating income (loss)	2,867	(23)	6,635	2,201
Oil sales (MBbl)	191	158	380	304
Gas sales (MMcf)	894	1,029	1,839	1,983
NGL sales (MBbl)	34	29	67	50
BOE sales	374	359	753	685
Average oil sales price (per Bbl) (1)	$90.59	$81.66	$90.61	$86.36
Average gas sales price (per Mcf) (1)	$3.51	$1.89	$3.26	$2.02
Average NGL sales price (per Bbl)	$31.46	$37.53	$33.12	$40.20
Average oil equivalent price (Boe)	$57.45	$44.44	$56.60	$47.16

(1) Revenue and average sales prices are before the impact of derivative activities.

Comparison of Three Months Ended June 30, 2013 to Three Months Ended June 30, 2012

Operating Revenue. During the three months ended June 30, 2013, operating revenue increased to $21.5 million from $15.9 million for the same period of 2012. The increase in revenue was primarily due to higher realized prices for oil and gas as well as increased sales volumes of oil and NGL. Increased prices contributed $2.9 million to revenue for the quarter ended June 30, 2013. Increase sales volumes of oil and NGL contributed $3.1 million to operating revenue for the period. Lower gas sales volumes negatively impacted earnings by $0.5 million and lower NGL prices had a $0.2 million negative impact on revenue.

Oil sales volumes increased to 191 MBbl during the quarter ended June 30, 2013 from 158 MBbl for the same period of 2012. The increase in oil sales was due to new wells brought on line offset by natural field declines and property sales. New wells brought on production contributed 68 MBbl for the three months ended June 30, 2013. Gas sales volumes decreased to 894 MMcf for the three months ended June 30, 2013 from 1,029 MMcf for the same period of 2012. The decrease in gas sales was due to natural field declines and property sales partially offset by new wells brought on line. New wells brought on line produced 71 MMcf for the three months ended June 30, 2013. NGL sales volumes increased to 34 MBbl for the three months ended June 30, 2013 from 29 MBbl for the same period of 2012. The increase in NGL sales was primarily due to increased gas production in West Texas, North Dakota and in the Eagle Ford that has a higher NGL content than our historical gas production.

Lease Operating Expenses ("LOE"). LOE for the three months ended June 30, 2013 increased to $6.2 million from $5.4 million for the same period of 2012. LOE per Boe for the three months ended June 30, 2013 was $16.49 compared to $15.01 for the same period of 2012. The increase in LOE was primarily due to a significant increase in non-recurring LOE as well as higher overall costs. The increase per Boe was due to higher overall costs for the three months ended June 30, 2013 as compared to the same period of 2012 which were partially offset by higher sales volumes for the three months ended June 30, 2013 as compared to the same period of 2012.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the three months ended June 30, 2013 increased to $1.9 million from $1.5 million for the same period of 2012, primarily as the result of higher sales volumes and higher realized prices.
General and Administrative (“G&A”) Expenses. G&A expenses, excluding stock-based compensation, were $2.1 million for the quarter ended June 30, 2013 compared to $1.7 million for the same period of 2012. The increase in G&A was primarily due to increased salaries and professional fees related to the proxy contest in 2013. G&A per Boe was $5.69 for the quarter ended June 30, 2013 compared to $4.69 for the same period of 2012. The increase per Boe was due to higher overall costs for the three months ended June 30, 2013 compared to the same period in 2012 which were partially offset by higher sales volumes for the three months ended June 30, 2013 as compared to the same period of 2012.

Stock-Based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of the Company's common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. For each of the three months ended June 30, 2013 and 2012, stock-based compensation was approximately $0.7 million.
Depreciation, Depletion and Amortization (“DD&A”) Expenses. DD&A expense for the three months ended June 30, 2013 increased to $5.8 million from $5.4 million for the same period of 2012. The increase was primarily the result of increased production volumes for the quarter ended June 30, 2013 as compared to the same period of 2012, as well as an increase in the full cost pool in 2013 as compared to 2012. DD&A expense per Boe for the three months ended June 30, 2013 was $15.45 compared to $15.00 in 2012. The increase in per Boe DD&A was due to a higher full cost pool in 2013 as compared to 2012.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of June 30, 2013, our net capitalized costs of oil and gas properties in the United States did not exceed the present value of our estimated proved reserves. As of June 30, 2013 the net capitalized cost of our oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $2.0 million, resulting in a write down of $2.0 million. As of June 30, 2012, the net capitalized cost of our oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $1.3 million, resulting in a write down of $1.3 million.

The risk that we will be required to write-down the carrying value of our oil and gas assets increases when oil and gas prices are depressed or volatile. In addition, write-downs may occur if we have substantial downward revisions in our estimated proved reserves. We cannot assure you that we will not experience additional write-downs in the future. If commodity prices decline or if any of our proved reserves are revised downward, a further write-down of the carrying value of our oil and gas properties may be required.

Interest Expense. Interest expense for each of the three months ended June 30, 2013 and 2012 was $1.3 million. Higher levels of debt for the three months ended June 30, 2012 were offset by lower interest rates.

(Gain) Loss on Derivative Contracts. We account for derivative contract gains and losses based on realized and unrealized amounts. The realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. Our derivative contract transactions do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. The net estimated value of our commodity derivative contracts was an asset of approximately $0.4 million as of June 30, 2013. When our derivative contract prices are higher than prevailing market prices, we incur realized and unrealized gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur realized and unrealized losses. For the three months ended June 30, 2013, we realized a loss on our commodity derivative contracts of $0.8 million. For the three months ended June 30, 2013 we incurred an unrealized gain of $7.5 million on our commodity derivative contracts. For the three months ended June 30, 2012, we realized a gain on our derivative contracts of $0.9 million, which included a realized gain of $1.5 million on our commodity swaps and a realized loss of $0.6 million on our interest rate swap. For the three months ended June 30, 2012 we incurred an unrealized gain of $10.3 million on our derivative contracts, which included an unrealized gain of $9.8 million on our commodity swaps and an unrealized gain of $0.5 million on our interest rate swap. Our interest rate swap expired in August of 2012.

Earnings from Equity Method Investment. We accounted for Blue Eagle under the equity method of accounting. Under this method, Abraxas' share of net income (loss) from the joint venture was reflected as an increase (decrease) in its investment account in "Investment in joint venture" and was also recorded as equity investment income (loss) in "Earnings from equity method investment." For the three months ended June 30, 2012, our net equity interest in the joint venture's income was $1.3 million. The joint venture was dissolved on September 4, 2012, effective August 31, 2012, with the assets being distributed to the joint venture partners. The dissolution of the joint venture was accounted for with the net investment in the joint venture being added to our full cost pool.

Income Tax. Income tax expense for the period ended June 30, 2013 is related to income taxes assessed as a result of an Internal Revenue Service examination of our 2009 Federal income tax return as well as various state taxes. For the year ended December 31, 2012, the Company accrued $310,000 in income tax expense related to the audit of its 2009 Federal tax return. This amount was determined by an analysis of what the amount that is greater than 50% likely to be paid upon final settlement. On July 23, 2013, we settled the assessment for $391,000 resulting in $81,000 being recognized as expense for the quarter ended June 30, 2013.

Comparison of Six Months Ended June 30, 2013 to Six Months Ended June 30, 2012

Operating Revenue. During the six months ended June 30, 2013, operating revenue increased to $42.7 from $32.3 million for the same period of 2012, The increase in revenue was primarily due to higher sales volumes of oil and NGL, which was offset by lower gas sales volumes. Increased sales volumes of oil and NGL contributed $7.4 million to operating revenues, while lower gas sales volumes had a negative impact of $0.5 million. Increased commodity prices for oil and gas contributed $3.7 million to revenue while lower NGL prices had a negative impact of $0.4 million for the six months ended June 30, 2013.

Oil sales volumes increased to 380 MBbl during the six months ended June 30, 2013 from 304 MBbl for the same period of 2012. The increase in oil sales was due to new wells being brought on line offset by natural field declines and property sales. New wells contributed 124 MBbl for the six months ended June 30, 2013. Gas sales volumes decreased to 1,839 MMcf for the six months ended June 30, 2013 from 1,983 MMcf for the same period of 2012. The decrease in gas sales was due to natural field declines and property sales partially offset by new wells brought on line. New wells brought onto production contributed 137 MMcf for the six months ended June 30, 2013. NGL sales volumes increased to 67 MBbl for the six months ended June 30, 2013 from 50 MBbl for the same period of 2012. The increase in NGL sales was primarily due to increased gas production in West Texas, North Dakota and Eagle Ford that has a higher NGL content than our historical gas production.

LOE. LOE for the six months ended June 30, 2013 increased to $12.6 million from $11.3 million for the same period of 2012. The increase in 2013 was due to an overall increase in the cost of services. LOE per Boe for the six months ended June 30, 2013 was $16.76 compared to $16.52 for the same period of 2012. The increase per Boe was due to higher costs which were partially offset by higher sales volumes for the six months ended June 30, 2013 as compared to the same period of 2012.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the six months ended June 30, 2013 increased to $3.8 million from $3.0 million for the same period of 2012. The increase was primarily the result of higher oil sales volumes and higher realized commodity prices for the six months ended June 30, 2013 as compared to the same period of 2012.

G&A Expenses. G&A expenses, excluding stock-based compensation, increased to $4.2 million for the first six months of 2013 from $3.1 million for the same period of 2012. The increase in G&A expense was primarily related to professional fees in connection with a proxy contest in 2013 as well as an increase in overall salaries. G&A expense per Boe was $5.56 for the six months ended June 30, 2013 compared to $4.53 for the same period of 2012. The increase per Boe was primarily due to higher costs offset by higher production volumes in the first six months of 2013 compared to the same period in 2012.

Stock-Based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of the Company's common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. For the six months ended June 30, 2013 and 2012, stock-based compensation was approximately $1.1 million and $1.2 million, respectively.

DD&A Expenses. DD&A expense for the six months ended June 30, 2013 increased to $12.3 million from $10.2 million for same period of 2012. The increase was primarily the result of increased production volumes, as well as an increase in the full cost pool in 2013 as compared to 2012. Our DD&A expense per Boe for the six months ended June 30, 2013 was $16.31 compared to $14.91 in 2012.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of June 30, 2013, our net capitalized costs of oil and gas properties in the United States did not exceed the present value of our estimated proved reserves. As of June 30, 2013 the net capitalized cost of our oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $2.0 million, resulting in a write down of $2.0 million. As of June 30, 2012, the net capitalized cost of our oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $1.3 million, resulting in a write down of $1.3 million.

The risk that we will be required to write-down the carrying value of our oil and gas assets increases when oil and gas prices are depressed or volatile. In addition, write-downs may occur if we have substantial downward revisions in our estimated proved reserves. We cannot assure you that we will not experience additional write-downs in the future. If commodity prices decline or if any of our proved reserves are revised downward, a further write-down of the carrying value of our oil and gas properties may be required.

Interest Expense. Interest expense for each of the six months ended June 30, 2013 and 2012 was $2.5 million. Higher levels of debt for the six months ended June 30, 2013 were offset by lower interest rates.

(Gain) Loss on Derivative Contracts. We account for derivative contract gains and losses based on realized and unrealized amounts. The realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. Our derivative contract transactions do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. The net estimated value of our commodity derivative contracts was an asset of approximately $0.4 million as of June 30, 2013. When our derivative contract prices are higher than prevailing market prices, we incur realized and unrealized gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur realized and unrealized losses. For the six months ended June 30, 2013, we realized a loss on our commodity derivative contracts of $1.7 million. For the six months ended June 30, 2013 we incurred an unrealized gain of $6.9 million on our commodity derivative contracts. For the six months ended June 30, 2012, we realized a gain on our derivative contracts of $0.9 million, which included a realized gain of $2.0 million on our commodity swaps and a realized loss of $1.1 million on our interest rate swap. For the six months ended June 30, 2012 we incurred an unrealized gain of $9.4 million on our derivative contracts, which included an unrealized gain of $8.5 million on our commodity swaps and an unrealized gain of $0.9 million on our interest rate swap. Our interest rate swap expired in August of 2012.

Earnings from Equity Method Investment. We accounted for Blue Eagle under the equity method of accounting. Under this method, Abraxas' share of net income (loss) from the joint venture was reflected as an increase (decrease) in its investment account in “Investment in joint venture” and was also recorded as equity investment income (loss) in “Earnings from equity method investment.” For the six months ended June 30, 2012, our net equity interest in the joint venture's income was $2.0 million. The joint venture was dissolved on September 4, 2012, effective August 31, 2012, with the assets being distributed to the joint venture partners. The dissolution of the joint venture was accounted for with the net investment in the joint venture being added to our full cost pool.

Income Tax. Income tax expense for the period ended June 30, 2013 is related to income taxes assessed as a result of an Internal Revenue Service examination of our 2009 Federal income tax return as well as various state taxes. For the year ended December 31, 2012, the Company accrued $310,000 in income tax expense related to the audit of its 2009 Federal tax return. This amount was determined by an analysis of what the amount that is greater than 50% likely to be paid upon final settlement. On July 23, 2013, we settled the assessment for $391,000 resulting in $81,000 being recognized as expense for the quarter ended June 30, 2013.

Liquidity and Capital Resources

General. The oil and gas industry is a highly capital intensive and cyclical business. Our capital requirements are driven principally by our obligations to service debt and to fund the following:

- the development and exploration of existing properties, including drilling and completion costs of wells;

- acquisition of interests in additional oil and gas properties; and

- production and transportation facilities.

The amount of capital expenditures we are able to make has a direct impact on our ability to increase cash flow from operations and, thereby, will directly affect our ability to service our debt obligations and to grow the business through the development of existing properties and the acquisition of new properties.

Our principal sources of capital are cash flow from operations, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, and if an opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financings on terms acceptable to us, if at all.

Working Capital (Deficit). At June 30, 2013, our current assets of approximately $65.9 million exceeded our current liabilities of $62.4 million resulting in working capital of $3.5 million. This compares to a working capital deficit of $31.5 million at December 31, 2012. Current assets at June 30, 2013 primarily consist of accounts receivable of $26.9 million and assets held for sale of $34.8 million. Current liabilities at June 30, 2013 primarily consisted of trade payables of $42.0 million, revenues due third parties of $14.0 million, current portion of derivative liabilities of $2.5 million, current maturities of long-term debt of $1.6 million and accrued liabilities of $2.2 million.

Capital expenditures. Capital expenditures during the six months ended June 30, 2013 were $33.5 million compared to $35.1 million during the same period of 2012.

The table below sets forth the components of these capital expenditures:

	Six Months Ended June 30,	
	2013	2012
Expenditure category:		
Development	$32,996	$31,608
Facilities and other	470	3,508
Total	$33,466	$35,116

During the six months ended June 30, 2013, capital expenditures were primarily for development of our existing oil and gas properties. During the six months ended June 30, 2012, capital expenditures were primarily for development of our existing oil and gas properties and the completion of the refurbishment of our drilling rig. We anticipate making capital expenditures in 2013 of $70.0 million. The 2013 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, and our ability to obtain permits for drilling locations. Our capital expenditures could also include expenditures for the acquisition of producing properties, if such opportunities arise. Additionally, the level of capital expenditures will vary during future periods depending on economic and industry conditions and commodity prices. Should the prices of oil and gas decline and if our costs of operations increase or if our production volumes decrease, our cash flows will decrease which may result in a reduction of the capital expenditure budget. If we decrease our capital expenditure budget, we may not be able to offset oil and gas production decreases caused by natural field declines.

Sources of Capital. The net funds provided by and/or used in each of the operating, investing and financing activities are summarized in the following table and discussed in further detail below:

	Six Months Ended June 30, 2013	2012
Net cash provided by operating activities	22,771	25,743
Net cash used in investing activities	(30,274)	(35,116)
Net cash provided by financing activities	7,818	9,680
Total	$315	$307

Operating activities during the six months ended June 30, 2013 provided $22.8 million of cash compared to providing $25.7 million in the same period of 2012. Net income plus non-cash expense items during the six months ended June 30, 2013 and 2012 and net changes in operating assets and liabilities accounted for most of these funds. In addition the monetization of our gas hedges on March 12, 2012 provided $12.4 million. Investing activities used $30.3 million during the six months ended June 30, 2013 compared to using $35.1 million for the same period of 2012. Funds used during the six months ended June 30, 2013 were expenditures for the development of our existing properties offset by property sales of $3.2 million. Funds used during the six months ended June 30, 2012 were expenditures for the development of our existing properties and the completion of the refurbishment of our drilling rig. Financing activities provided $7.8 million for the six months ended June 30, 2013 compared to providing $9.7 million for the same period in 2012. Funds provided during the six months ended June 30, 2013 were primarily borrowings under our credit facility. Funds provided during the six months ended June 30, 2012 were primarily proceeds from borrowings under our credit facility.

Future Capital Resources. Our principal sources of capital going forward are cash flows from operations, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, and if an opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete financing on terms acceptable to us, if at all.

Cash from operating activities is dependent upon commodity prices and production volumes. A decrease in commodity prices from current levels could reduce our cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans. Unless we otherwise expand and develop reserves, our production volumes may decline as reserves are produced. In the future we may continue to sell producing properties, which could further reduce our production volumes. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration and development activities, acquire additional producing properties or identify and develop additional behind-pipe zones or secondary recovery reserves. We believe our numerous drilling opportunities will allow us to increase our production volumes; however, our drilling activities are subject to numerous risks, including the risk that no commercially productive oil and gas reservoirs will be found. If our proved reserves decline in the future, our production will also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility will also decline. The risk of not finding commercially productive reservoirs will be compounded by the fact that 49% of our total estimated proved reserves at December 31, 2012 were classified as undeveloped.

We have in the past, and may, in the future, sell producing properties. Most recently, in the second quarter of 2013, we agreed to sell certain non-core, non-operated properties for net anticipated proceeds of $34.8 million. It is anticipated that this transaction will close in August 2013. In the first and second quarter of 2013, we sold certain non-core assets for net proceeds of $3.2 million and in the third quarter of 2012, we sold certain non-core assets for combined net proceeds of approximately $21.5 million. The net proceeds were used to repay outstanding indebtedness under our credit facility and general corporate purposes.

Contractual Obligations. We are committed to making cash payments in the future on the following types of agreements:

- Long-term debt, and
- Operating leases for office facilities.

Below is a schedule of the future payments that we are obligated to make based on agreements in place as of June 30, 2013:

	Payments due in twelve month periods ending:				
	Total	June 30, 2014	June 30, 2015-2016	June 30, 2017-2018	Thereafter
Long-term debt (1)	$132,657	$1,634	$129,434	$1,589	$—
Interest on long-term debt (2)	8,726	4,347	4,351	28	—
Lease obligations (3)	31	31	—	—	—
Total	$141,414	$6,012	$133,785	$1,617	$—

(1) These amounts represent the balances outstanding under our credit facility, the rig loan agreement and the real estate lien note. These repayments assume that we will not borrow additional funds.
(2) Interest expense assumes the balances of long-term debt at the end of the period and current effective interest rates.
(3) Lease on office space in Calgary, Alberta, which expires on January 31, 2014 and office space in Dickinson, North Dakota, which expires on August 31, 2013.

We maintain a reserve for cost associated with the retirement of tangible long-lived assets. At June 30, 2013, our reserve for these obligations totaled $10.1 million for which no contractual commitment exists. For additional information relating to this obligation, see Note 1 of the Notes to Condensed Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At June 30, 2013, we had no existing off-balance sheet arrangements, as defined under SEC regulations, which have or are reasonably likely to have a current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Contingencies. From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At June 30, 2013, we were not engaged in any legal proceedings that were expected, individually or in the aggregate, to have a material adverse effect on the Company.

Other Obligations. We make and will continue to make substantial capital expenditures for the acquisition, development, exploration and production of oil and gas. In the past, we have funded our operations and capital expenditures primarily through cash flow from operations, sales of properties, sales of production payments and borrowings under our credit facilities and other sources. Given our high degree of operating control, the timing and incurrence of capital expenditures is largely within our discretion.

Long-Term Indebtedness

The following table summarizes the Company’s long-term debt:

	June 30, 2013	December 31, 2012
Credit facility	$121,000	$113,000
Rig loan agreement	7,000	7,000
Real estate lien note	4,657	4,758
	132,657	124,758
Less current maturities	(1,634)	(657)