UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

(Amendment No. 1)

(Mark One)

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

For the fiscal year ended December 31, 2012

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

For the transition period from to

Commission File Number 001-32657

NABORS INDUSTRIES LTD.

(Exact name of registrant as specified in its charter)

Bermuda (State or Other Jurisdiction of Incorporation or Organization)	**980363970** (I.R.S. Employer Identification No.)
Crown House, Second Floor **4 Par-La-Ville Road** **Hamilton, HM08** **Bermuda** (Address of principal executive offices)	**N/A** (Zip Code)

(441) 292-1510

(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

Title of each class	**Name of each exchange on which registered**
Common shares, $.001 par value per share	The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Securities Exchange Act of 1934:

None.

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months. YES x NO o

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

10-K or any amendment to this Form 10-K. x

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

Large Accelerated Filer x	Accelerated Filer o
Non-accelerated Filer o	Smaller Reporting Company o

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

The aggregate market value of the 275,797,408 common shares, par value $.001 per share, held by non-affiliates of the registrant, based upon the closing price of our common shares as of the last business day of our most recently completed second fiscal quarter, June 30, 2012, of $14.40 per share as reported on the New York Stock Exchange, was $3,971,482,675. Common shares held by each officer and director and by each person who owns 5% or more of the outstanding common shares have been excluded in that such persons may be deemed affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

DOCUMENTS INCORPORATED BY REFERENCE (to the extent indicated herein)

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NABORS INDUSTRIES LTD.

Form 10-K/A

For the Year Ended December 31, 2012

Explanatory Note

This Amendment No.1 on Form 10-K/A is being filed to amend our Annual Report on Form 10-K for the year ended December 31, 2012, originally filed with the Securities and Exchange Commission on March 1, 2013 (the Original Filing). We are filing this amendment to present separate audited financial statements for Sabine Oil & Gas LLC, a former non-consolidated subsidiary, that we determined were required pursuant to Regulation S-X, Rule 3-09, Separate financial statements of subsidiaries not consolidated and 50 percent or less owned persons. The audited financial statements of Sabine Oil and Gas LLC were not available for inclusion with our Original Filing, but are required to be filed as an amendment within 90 days after the end of our fiscal year.

Except as described above, this Amendment No. 1 does not amend any information set forth in the Original Filing and we have not updated disclosures contained therein to reflect any events that occurred on a date subsequent to the date of the Original Filing.

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ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

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

(1) Financial Statements

	Page No.
Consolidated Balance Sheets as of December 31, 2012 and 2011	*
Consolidated Statements of Income (Loss) for the Years Ended December 31, 2012, 2011 and 2010	*
Consolidated Statements of Other Comprehensive Income (Loss) for the Years Ended December 31, 2012, 2011 and 2010	*
Consolidated Statements of Cash Flows for the Years Ended December 31, 2012, 2011 and 2010	*
Consolidated Statements of Changes in Shareholders Equity for the Years Ended December 31, 2012, 2011 and 2010	*

(2) Financial Statement Schedules

	Page No.
Schedule II Valuation and Qualifying Accounts	*
Schedule III Financial Statements and Notes for Sabine Oil & Gas LLC	8

All other supplemental schedules are omitted because of the absence of the conditions under which they are required or the required information is included in the financial statements or the related notes.

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*Previously filed.

(b) Exhibits

[redacted]

[redacted]

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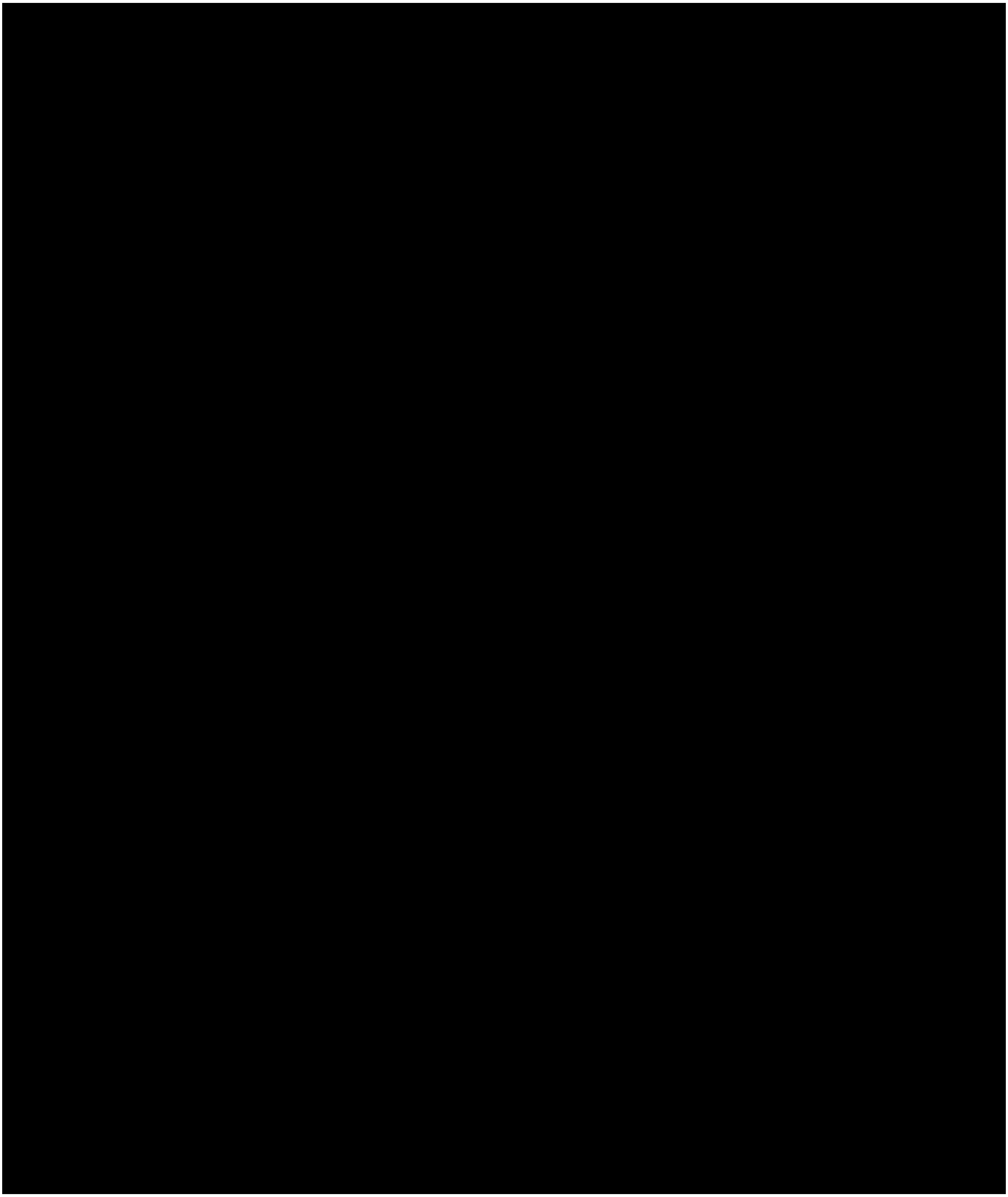

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[redacted]

** Filed herewith.

(+) Management contract or compensatory plan or arrangement.

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SIGNATURES

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

NABORS INDUSTRIES LTD.

By:	/s/ R. Clark Wood R. Clark Wood Principal Accounting and Financial Officer
	Date: April 1, 2013

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Schedule III Financial Statements and Notes for Sabine Oil & Gas LLC

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Item 15. Exhibits, Financial Statement Schedules

Schedule III Financial Statements and Notes for Sabine Oil & Gas LLC

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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Independent Auditor s Reports

The Member of Sabine Oil & Gas LLC

We have audited the accompanying consolidated financial statements of Sabine Oil & Gas LLC (formerly known as NFR Energy LLC) and its subsidiaries, which comprise the consolidated balance sheets as of December 31, 2012 and 2011, and the related consolidated statements of operations, of member s capital and of cash flows for each of the three years in the period ended December 31, 2012.

Management s Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor s Responsibility

Our responsibility is to express an opinion on the consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company s preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Sabine Oil & Gas LLC and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in accordance with accounting principles generally accepted in the United States of America.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

March 31, 2013

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Consolidated Financial Statements

Sabine Oil & Gas LLC

Consolidated Balance Sheets

As of December 31, 2012 and 2011

	December 31, 2012	December 31, 2011
	(in thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ 6,193	$ 4,306
Accounts receivable, net	33,190	24,872
Prepaid expenses and other current assets	3,718	5,649
Derivative instruments	54,855	90,838
Other short term assets	515	
Total current assets	98,471	125,665
Property, plant and equipment:		
Oil and gas properties (full cost method)		
Proved	2,839,900	2,292,875
Unproved	332,898	208,230
Gas gathering and processing equipment	15,564	39,763
Office furniture and fixtures	9,262	8,963
	3,197,624	2,549,831
Accumulated depletion, depreciation and amortization	(1,851,998)	(1,041,969)
Total property, plant and equipment, net	1,345,626	1,507,862
Other assets:		
Derivative instruments	6,731	36,920
Deferred financing costs	29,827	14,669
Goodwill	173,547	
Other long term assets	853	
Total other assets	210,958	51,589
Total assets	$ 1,655,055	$ 1,685,116
Liabilities and member s capital		
Current liabilities:		
Accounts payable - trade	$ 2,965	$ 5,221
Accounts payable - related party	3,585	12,126
Royalties payable	8,814	8,820
Accrued interest payable	15,523	13,908
Accrued exploration and development	19,805	39,772
Accrued operating expenses and other	31,102	26,647
Derivative instruments	3,875	56
Other short term obligations	251	532
Total current liabilities	85,920	107,082
Long term liabilities:		
Revolving credit facility	405,000	418,000
Second lien term loan	490,127	
Senior notes	347,411	346,782
Asset retirement obligation	13,580	15,348
Derivative instruments	18,017	17,409
Other long term obligations	5,151	322

Total long term liabilities		1,279,286		797,861
Commitments and contingencies				
Member s capital:				
Member s capital		1,533,008		1,267,698
Amounts receivable from member				(41)
Accumulated deficit		(1,306,203)		(620,585)
Accumulated other comprehensive income		63,044		130,837
Total controlling interests member s capital		289,849		777,909
Noncontrolling interests				2,264
Total member s capital		289,849		780,173
Total liabilities and member s capital	$	1,655,055	$	1,685,116

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

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Consolidated Financial Statements

Sabine Oil & Gas LLC

Consolidated Statements of Operations

For the Years Ended December 31, 2012, 2011 and 2010

	For the Year Ended December 31,		
	2012	**2011** (in thousands)	**2010**
Revenues			
Oil, natural gas and natural gas liquids	$ 181,098	$ 204,989	$ 132,062
Gain on derivative instruments	107,374	72,517	51,104
Other	24	131	1,390
Total revenues	288,496	277,637	184,556
Operating expenses			
Lease operating	41,011	27,113	18,637
Workover	2,638	2,903	848
Marketing, gathering, transportation and other	21,167	19,717	13,730
Production and ad valorem taxes	4,400	7,775	5,483
General and administrative	21,394	23,543	20,605
Depletion, depreciation and amortization	96,096	82,178	52,490
Gain on bargain purchase	(14,470)	(99,548)	(372)
Accretion	862	628	493
Bad debt	40	3	18
Impairments	730,916	29,921	1,711
Loss on sale of assets	9,880		
Total operating expenses	913,934	94,233	113,643
Other income (expenses)			
Interest expense	(49,387)	(39,632)	(33,468)
Gain (loss) on derivative instruments	(10,312)	(25,799)	2,547
Other expense	(498)	(389)	(963)
Total other expenses	(60,197)	(65,820)	(31,884)
Net income (loss) including noncontrolling interests	(685,635)	117,584	39,029
Less: Net loss (income) applicable to noncontrolling interests	17	(117)	(260)
Net income (loss) applicable to controlling interests	$ (685,618)	$ 117,467	$ 38,769

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

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Consolidated Financial Statements

Sabine Oil & Gas LLC

Consolidated Statement of Member s Capital

For the Years ended December 31, 2012, 2011 and 2010

(in thousands)

	Comprehensive Income (Loss)	Member s Capital		Amounts Receivable from Member	Retained Deficit	Other Comprehensive Income (loss)	Noncontrolling Interests	Total Member s Capital
		Units	Value					
Balance as of December 31, 2009		1,007	$ 1,005,607	$ (358)	$ (776,821)	$ 55,399	$ 2,775	$ 286,602
Member s contributions		60	60,000					60,000
Amounts receivable from member				208				208
Distributions to member for state tax withholding			(424)					(424)
Comprehensive income:								
Net income applicable to controlling interests	$ 38,769				38,769			38,769
Unrealized gain on derivative contracts	50,323					50,323		50,323
Comprehensive income applicable to controlling interests	89,092							
Net income applicable to noncontrolling interests	260						260	260
Comprehensive income including noncontrolling interests	$ 89,352							
Balance as of December 31, 2010		1,067	$ 1,065,183	$ (150)	$ (738,052)	$ 105,722	$ 3,035	$ 435,738
Member s contributions		203	203,000					203,000
Amounts receivable from member				109				109
Distributions - noncontrolling interests							(888)	(888)
Distributions to member for state tax withholding			(485)					(485)
Comprehensive income:								
Net income applicable to controlling interests	$ 117,467				117,467			117,467
Unrealized gain on derivative contracts	25,115					25,115		25,115
Comprehensive income applicable to controlling interests	142,582							
Net income applicable to noncontrolling interests	117						117	117
Comprehensive income including noncontrolling interests	$ 142,699							
Balance as of December 31, 2011		1,270	$ 1,267,698	$ (41)	$ (620,585)	$ 130,837	$ 2,264	$ 780,173
Member s contributions		88	87,467					87,467
In-kind contributions		178	178,000					178,000
Amounts receivable from member				41				41
Distributions - noncontrolling interests							(175)	(175)
Distributions to member for state tax withholding			(157)					(157)

Sale of noncontrolling interests							(2,072)	(2,072)
Comprehensive loss:								
Net loss applicable to controlling interests	$ (685,618)				(685,618)			(685,618)
Unrealized loss on derivative contracts	(67,793)					(67,793)		(67,793)
Comprehensive loss applicable to controlling interests	(753,411)							
Net loss applicable to noncontrolling interests	(17)						(17)	(17)
Comprehensive loss including noncontrolling interests	$ (753,428)							
Balance as of December 31, 2012		**1,536**	**$ 1,533,008**	**$**	**$ (1,306,203)**	**$ 63,044**	**$**	**$ 289,849**

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

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Consolidated Financial Statements

Sabine Oil & Gas LLC

Consolidated Statement of Cash Flows

For the Years ended December 31, 2012, 2011 and 2010

	For the Year Ended December 31, 2012	2011 (in thousands)	2010
Cash flows from operating activities:			
Net income (loss), including noncontrolling interests	$ (685,635)	$ 117,584	$ 39,029
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	96,096	82,178	52,490
Impairments	730,916	29,921	1,711
Loss on sale of assets	10,531	600	1,138
Bad debt expense	40	3	18
Accretion expense	862	628	493
Accrued interest expense	2,372	1,458	11,953
Rent expense and amortization of deferred rent	(532)	(38)	(321)
Amortization of deferred financing costs	4,020	2,817	4,325
(Gain) loss on derivative instruments	7,940	23,844	(1,672)
Amortization of option premiums	(56)		3,239
Amortization of prepaid expenses	2,546	2,482	1,762
Gain on bargain purchase	(14,470)	(99,548)	(372)
Non cash distributions to member	(157)	(485)	(424)
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(8,471)	(8,858)	3,610
Increase in other assets	(5,811)	(6,713)	(5,393)
Increase (decrease) in accounts payable, royalties payable and accrued liabilities	3,975	13,159	(5,871)
Net cash provided by operating activities	**144,166**	**159,032**	**105,715**
Cash flows from investing activities:			
Oil and gas property additions	(170,970)	(292,648)	(270,548)
Oil and gas property acquisitions	(559,066)	(385,218)	(64,525)
Cash received from insurance proceeds	12,680		2,343
Gas processing equipment additions	(5,409)	(3,810)	(246)
Other asset additions	(384)	(2,952)	(425)
Proceeds from sale of assets	35,764	3,706	8,012
Net cash used in investing activities	**(687,385)**	**(680,922)**	**(325,389)**
Cash flows from financing activities:			
Borrowings under 1st lien revolving credit facility	123,000	584,500	176,500
Borrowings under 2nd lien revolving credit facility	490,000		345,597
Debt repayments	(136,000)	(260,500)	(347,000)
Deferred financing costs	(19,227)	(4,462)	(13,683)
Member s contributions	87,508	203,109	60,208
Distributions - noncontrolling interests	(175)	(888)	

Net cash provided by financing activities	**545,106**	**521,759**	**221,622**
Net increase (decrease) in cash and cash equivalents	1,887	(131)	1,948
Cash and cash equivalents, beginning of period	4,306	4,437	2,489
Cash and cash equivalents, end of period	**$ 6,193**	**$ 4,306**	**$ 4,437**

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

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1. Organization

Effective December 19, 2012, NFR Energy LLC was renamed Sabine Oil & Gas LLC (Sabine or the Company). The Company was established as a Delaware limited liability company in late 2006 by Ramshorn Investments, Inc. (Ramshorn), a wholly owned subsidiary of Nabors Industries Ltd. (Nabors), and First Reserve Corporation (First Reserve), who formed the Company as a joint venture to invest in oil and natural gas exploration opportunities within the onshore U.S. market. Additional equity contributions were made by certain members of the Company s management and the board of representatives (the Member).

On November 5, 2010, the Company formed NFR Holdings LLC, subsequently renamed Sabine Oil & Gas Holdings LLC, as a Delaware limited liability company (Holdings), at which time Holdings formed NFR Holdings II LLC, subsequently renamed Sabine Oil & Gas Holdings II LLC, as a Delaware limited liability company (Holdings II), and Holdings II formed NFR Merger Sub LLC, as a Delaware limited liability company (Merger Sub). Effective November 5, 2010, Merger Sub merged into the Company, with the Company being the surviving entity (the Merger) and all of the membership interests of the Company were converted into membership interests owned by Holdings. In addition to membership interests, all incentive units are maintained and held by Holdings. As a consequence of the Merger, Holdings II is the single member owner of the Company. The change in legal structure had no direct impact on the financial statements of the Company.

In December 2012, Nabors sold its equity interest in Holdings to First Reserve resulting in affiliates of First Reserve owning approximately 99.6% of the common equity interests of Holdings.

The Company is operating in one segment and is pursuing development and exploration projects in a variety of forms including operated and non-operated working interests, joint ventures, farm-outs, and acquisitions, including conventional and unconventional resources. Sabine is a holding company within which it conducts its operations through, and its operating assets are owned by, its subsidiaries.

2. Significant Accounting Policies

Basis of Presentation

The Company presents its consolidated financial statements in accordance with U.S. generally accepted accounting principles (GAAP). The accompanying consolidated financial statements include Sabine and its subsidiaries. All significant intercompany transactions have been eliminated. Certain other reclassifications have been made to prior periods to conform to the current presentation.

Cash and Cash Equivalents

All highly liquid investments purchased with an initial maturity of three months or less are considered to be cash equivalents.

Concentration of Credit Risk

The Company s significant receivables are comprised of oil and natural gas revenue receivables. The amounts are due from a limited number of entities; therefore, the collectability is dependent upon the general economic conditions of a few purchasers. The Company regularly reviews collectability and establishes the allowance for doubtful accounts as necessary using the specific identification method. The receivables are not collateralized.

Derivative instruments subject the Company to a concentration of credit risk. See Note 8 Derivative Financial Instruments

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2. Significant Accounting Policies (continued)

Inventory

Inventory, which is included in prepaid expenses and other, consists principally of tubular goods, spare parts, and equipment, that is used in our drilling operations. The inventory balance, net of impairments, was $1.6 million and $4.1 million as of December 31, 2012 and 2011, respectively. Inventory is stated at the lower of weighted average cost or market. Under this method, the total impairments relating to obsolete inventory was $1.2 million, $1.4 million and $1.7 million in 2012, 2011 and 2010, respectively, and included in Impairments in the Consolidated Statements of Operations.

Oil and Natural Gas Properties and Equipment

The Company uses the full cost method of accounting for its investment in oil and natural gas properties. Under this method, the Company capitalizes all acquisition, exploration, and development costs incurred for the purpose of finding oil and natural gas reserves, including salaries, benefits, and other internal costs directly attributable to these activities. The Company capitalized $2.7 million, $3.5 million and $3.5 million of internal costs in 2012, 2011 and 2010, respectively. Costs associated with production and general corporate activities, however, are expensed in the period incurred. The Company also includes the present value of its dismantlement, restoration, and abandonment costs within the capitalized oil and natural gas property balance (see Asset Retirement Obligation below). Unless a significant portion of the Company s proved reserve quantities is sold (greater than 25%), proceeds from the sale of oil and natural gas properties are accounted for as a reduction to capitalized costs, and gains and losses are not recognized unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas.

Depletion of exploration, development costs and production equipment is computed using the units-of-production method based upon estimated proved oil and natural gas reserves. The costs of unproved properties are withheld from the depletion base until such time as they are either developed or abandoned. The properties are reviewed on a quarterly basis for impairment, and if impaired, are reclassified to proved property and included in the ceiling test and depletion calculations.

Under the full cost method of accounting, a ceiling test is performed on a quarterly basis. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test determines a limit on the book value of oil and natural gas properties. The capitalized costs of proved oil and natural gas properties, net of Accumulated depletion, depreciation and amortization (accumulated DD&A) on our Consolidated Balance Sheets, may not exceed the estimated future net cash flows from proved oil and natural gas reserves, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on our Consolidated Balance Sheets, using the unweighted average first-day-of-the-month prices for the prior twelve month period ended December 31, 2012, 2011 and 2010 (adjusted for quality and basis differentials), held flat for the life of production, discounted at 10%, plus the cost of unevaluated properties and major development projects excluded from the costs being amortized. If capitalized costs exceed this limit, the excess is charged to expense and reflected as accumulated DD&A.

For the years ended December 31, 2012 and 2011 the Company recognized an impairment of $718.1 million and $25.7 million, respectively, for the carrying value of proved oil and gas properties in excess in excess of the ceiling limitation as a result of the decline of natural gas prices. The

Company did not recognize any impairment charges relating to oil and natural gas properties in 2010. The average of the historical unweighted first-day-of-the-month prices for the prior twelve month periods ended December 31, 2012 and March 31, 2013 was $2.76 and $2.95 per Mcf for natural gas, respectively. Cash flow hedges of natural gas production in place increased the ceiling value by $89.4 million at December 31, 2012. The Company could have a further reduction in our asset carrying value for oil and gas properties upon a decline in the average of the historical unweighted first-day-of-the-month natural gas prices for the prior twelve month periods.

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2. Significant Accounting Policies (continued)

Gathering assets and related facilities, certain other property and equipment, and furniture and fixtures are depreciated using the straight-line method based on the estimated useful lives of the respective assets, generally ranging from 3 to 30 years. In accordance with Accounting Standards Codification (ASC) 360-35 Impairment or disposal of long lived assets , these assets are tested for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is then recognized if the carrying amount is not recoverable and exceeds fair value. In 2012, we recorded impairment charges for gas gathering and processing equipment of $11.5 million based on an expected present value technique and estimated future cash flows using current volume throughput and pricing assumptions, for properties which were subsequently sold in August 2012. No impairment charges for gas gathering and processing equipment were recognized in 2011 or 2010. Leasehold improvements are amortized over the shorter of their economic lives or the lease term. Repairs and maintenance costs are expensed in the period incurred.

The Company s Depletion, depreciation and amortization (DD&A) expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities.

For the years ended December 31, 2012, 2011 and 2010, the Company received insurance proceeds of $12.7 million, $0.0 million and $2.3 million, respectively, which were netted with the replacement costs recognized in oil and gas properties. Insurance proceeds were received as the result of control of well events during drilling or completion operations in East Texas.

Capitalized Interest

The Company capitalizes interest costs to oil and natural gas properties on expenditures made in connection with exploration and development projects that are not subject to current depletion. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use. The Company capitalized $4.3 million and $5.9 million of interest during the years ended December 31, 2012 and 2011, respectively.

Leases

The Company accounts for leases with escalation clauses and rent holidays on a straight-line basis in accordance with Accounting Standards Codification (ASC) 840, Leases . The deferred rent expense liability associated with future lease commitments was reported under the caption Other long term obligations on our Consolidated Balance Sheets.

Derivative Instruments and Hedging Activities

The Company uses derivative financial instruments to achieve a more predictable cash flow from its oil and natural gas production by reducing its exposure to price fluctuations. Such derivative instruments, which are placed with major financial institutions who are participants in the Company s Credit Facility (see Note 5) that the Company believes are minimal credit risks, may take the form of forward contracts, futures contracts, swaps, options, or basis swaps.

At December 31, 2012, with the exception of basis swaps, substantially all of our oil and natural gas derivative contracts are settled based upon reported New York Mercantile Exchange (NYMEX) prices. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty and we have netting arrangements with all of our counterparties that provide for offsetting payables against receivables from separate hedging arrangements with that counterparty. The oil and natural gas reference prices, upon which the commodity derivative contracts are based, reflect various market indices that have a generally high degree of historical correlation with actual prices received by the Company for its oil and natural gas production. Our fixed-price swap and collar agreements are used to fix the sales price for our anticipated future oil and natural gas production. Upon settlement, the Company receives a fixed price for the hedged commodity and receives or pays our counterparty a floating market price, as defined in each instrument. The instruments are settled monthly. When the floating price exceeds the fixed price for a contract month, the Company pays our counterparty.

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2. Significant Accounting Policies (continued)

When the fixed price exceeds the floating price, our counterparty is required to make a payment to the Company. The Company has designated these swap and collar agreements as cash flow hedges.

The Company s non-designated positions at December 31, 2012 included natural gas basis swaps and both oil and natural gas options. The basis swaps are used to minimize exposure to fluctuating differentials on certain pricing indices against other pricing indices. These instruments are settled monthly. Upon settlement, the Company will pay a floating price on a specified index, and the counterparty will pay a floating price on a different specified index, either of which may include a specified differential. When the Company s specified index price is less than the counterparties, the counterparty will pay the Company. When the Company s specified index price is greater than the counterparties specified index price, the Company will pay the counterparty. Additionally, the Company has bought natural gas puts, sold natural gas and oil calls and sold oil puts. For the natural gas and oil calls, the counterparty has the option to purchase a set volume of the contracted commodity at a contracted price on a contracted date in the future. For the natural gas and oil puts, the counterparty has the option to sell a contracted volume of the commodity at a contracted price on a contracted date in future.

The Company accounts for these activities pursuant to ASC 815, Derivatives and Hedging which requires that derivative instruments other than those that meet the normal purchases and sales exception, be recorded on the balance sheets as either an asset or liability measured at fair value (which is generally based on information obtained from independent parties). ASC 815 also requires that changes in fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Hedge accounting treatment allows unrealized gains and losses on cash flow hedges to be deferred in accumulated other comprehensive income. Realized gains and losses from the Company s oil and natural gas cash flow hedges are generally recognized in Gain (loss) on derivative instruments located in Revenue in the Consolidated Statement of Operations when the forecasted transaction occurs. Gains and losses from the change in fair value of derivative instruments that do not qualify for hedge accounting are reported in current-period earnings as a Gain (loss) on derivative instruments located in Other income in the Consolidated Statement of Operations. If at any time the likelihood of occurrence of a hedged forecasted transaction ceases to be probable, hedge accounting under ASC 815 will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings. Amounts recorded in Accumulated other comprehensive income in the Consolidated Balance Sheets prior to the change in the likelihood of occurrence of the forecasted transaction will remain in Accumulated other comprehensive income until such time as the forecasted transaction impacts earnings. If it becomes probable that the original forecasted production will not occur, then the derivative gain or loss would be reclassified from Accumulated other comprehensive income into earnings immediately. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative instruments and the hedged item over time, and any ineffectiveness is immediately reported as unrealized Gain (loss) on derivative instruments in the Consolidated Statement of Operations.

Deferred Financing Costs

Deferred financing costs of approximately $19.2 million and $4.5 million were incurred during 2012 and 2011, respectively. Deferred financing costs in 2012 include costs associated with the amendment of the Company s Credit Facility and Second Lien. Deferred financing costs in 2011 include costs associated with the amendment of the Company s Credit Facility. Deferred financing costs are being amortized over the life of the respective obligations with $3.2 million included in interest expense in 2012. As a result of a reduction in the borrowing base of our Credit Facility in 2012, the Company also expensed $0.8 million, in 2012.

Financial Instruments

The Company s financial instruments including cash and cash equivalents, accounts receivable, and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. The Company s credit facilities are reported at carrying value which approximates fair value based on current rates applicable to similar instruments. Since considerable judgment is required to develop estimates of fair value, the estimates provided are not necessarily indicative of the amounts the Company could realize upon the purchase or refinancing of such instruments. The

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2. Significant Accounting Policies (continued)

Company s derivative instruments are reported at fair value based on Level 2 fair value methodologies and the 2017 notes are reported at carrying value but further compared to fair value based on Level 2 fair value methodologies (see Note 9).

Goodwill

Goodwill represents the excess of the purchase price of an asset over the estimated fair value of the assets acquired. The Company assesses the carrying amount of goodwill by testing for impairment annually and when impairment indicators arise. Goodwill totaled $173.5 million at December 31, 2012 with no balance as of December 31, 2011. The goodwill was recognized during 2012 as a result of our December 2012 acquisitions discussed in Note 4 Property Acquisitions and Divestitures. No impairment of goodwill was recognized during 2012, 2011, or 2010.

Asset Retirement Obligation

The Company follows ASC 410, Asset Retirement and Environmental Obligations . If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, we record a liability (an asset retirement obligation or ARO) on our Consolidated Balance Sheets and capitalize the present value of the asset retirement cost in Oil and gas properties in the period in which the retirement obligation is incurred. In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation assuming the normal operation of the asset, using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for our company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis within the related full cost pool. The capitalized costs associated with an ARO are included in the amortization base for purposes of calculating the ceiling test.

The information below reconciles the value of the asset retirement obligation:

	For the year ended December 31, 2012	2011
	(in thousands)	
Beginning balance as of December 31, 2011	$ 15,348	$ 9,213
Liabilities incurred	1,887	5,693
Liabilities settled	(4,791)	(186)
Change in estimate	274	
Accretion expense	862	628
Ending balance as of December 31, 2012	$ 13,580	$ 15,348

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2. Significant Accounting Policies (continued)

Revenue Recognition

The Company records revenues from the sales of oil, natural gas and natural gas liquids when produced, sold and collectability is ensured. The Company may have an interest with other producers in certain properties, in which case the Company uses the sales method to account for gas imbalances. Under this method, revenue is recorded on the basis of natural gas actually sold by the Company. The Company also reduces revenue for other owners natural gas sold by the Company that cannot be volumetrically balanced in the future due to insufficient remaining reserves. The Company s remaining over- and under-produced gas balancing positions are considered in the Company s proved oil and natural gas reserves. The Company had no material gas imbalances at December 31, 2012 and 2011.

Use of Estimates

The preparation of the consolidated financial statements for the Company in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

The Company s consolidated financial statements are based on a number of significant estimates, including oil, natural gas and natural gas liquids reserve quantities that are the basis for the calculation of DD&A and impairment of oil, natural gas and natural gas liquids properties, and timing and costs associated with its retirement obligations.

Income Taxes

The Company is a limited liability company treated as a partnership for federal and state income tax purposes with all income tax liabilities and/or benefits of the Company being passed through to the Member. As such, no recognition of federal or state income taxes for the Company or its subsidiaries that are organized as limited liability companies have been provided for in the accompanying consolidated financial statements. Any uncertain tax position taken by the member is not an uncertain position of the Company.

In accordance with the operating agreement of Sabine, to the extent possible without impairing the Company s ability to continue to conduct its business and activities, and in order to permit its Member to pay taxes on the taxable income of the Company, Sabine would be required to make distributions to the Member in the amount equal to the estimated tax liability of such Member computed as if the Member paid income tax at the highest marginal federal and state rate applicable to an individual resident of New York, New York, in the event that taxable income is generated for the Member. There was no taxable income and therefore no distributions to the Member in 2012, 2011 or 2010.

Recent Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update 2011-5, Presentation of Comprehensive Income (ASU 2011-5). The FASB has issued new guidance for how companies must present other comprehensive income (OCI) and its components in their financial statements. The guidance applies to all companies that report items of OCI but perhaps is most relevant for companies that have historically presented components of OCI as part of their statement of changes in stockholders equity which is no longer an option available under this guidance. ASU 2011-5 is intended to increase the prominence of items that are recorded in OCI and improve comparability and transparency in financial statements and allow for a more prominent evaluation of the effect of OCI on a company s overall performance. The new guidance described in ASU 2011-05 will supersede the presentation options in Topic 220 (previously known as Statement of Financial Accounting Standards No. 130, Reporting Comprehensive Income). The guidance, however, affects only the presentation of OCI, not the components that must be reported in OCI. ASU 2011-5 is effective for private companies for annual periods beginning after December 15, 2012, and interim and annual periods thereafter. The Company will adopt ASU 2011-5 in the first quarter of 2013.

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2. **Significant Accounting Policies (continued)**

In December 2011, the FASB issued Accounting Standards Update 2011-11, Disclosures About Offsetting Assets and Liabilities (ASU 2011-11). ASU 2011-11 amends the disclosure requirements on offsetting assets and liabilities by requiring improved information about financial instruments and derivative instruments that have a right of offset or are subject to an enforceable master netting arrangement or similar agreement. This information will enable users of a company s financial statements to evaluate the effect or potential effect of netting arrangements on a company s financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments. The Company is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. The Company will provide the disclosures required by those amendments retrospectively for all comparative periods presented in the first quarter of 2013.

In December 2010, the FASB issued Accounting Standards Update 2010-29, Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations (ASU 2010-29). ASU 2010-29 clarifies that when presenting comparative pro forma financial statements in conjunction with business combination disclosures, revenue and earnings of the combined entity should be presented as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period. In addition, the update requires a description of the nature and amount of material, nonrecurring pro forma adjustments included in pro forma revenue and earnings that are directly attributable to the business combination. This update is effective prospectively for business combinations that occur on or after the beginning of the first annual reporting period after December 15, 2010. As ASU 2010-29 relates to disclosure requirements, there will be no impact on the Company s financial condition or results of operations.

In December 2010, the FASB issued Accounting Standards Update 2010-28, Intangibles Goodwill and Other: When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts (ASU 2010-28). ASU 2010-28 requires step two of the goodwill impairment test to be performed when the carrying value of a reporting unit is zero or negative, if it is more likely than not that a goodwill impairment exists. The requirements of this update are effective for fiscal years beginning after December 15, 2010. The Company recognized goodwill in December 2012 and will test goodwill for impairment as applicable.

In February 2010, the FASB issued Accounting Standards Update 2010-09, Amendments to Certain Recognition and Disclosure Requirements (ASU 2010-09). This update amends Subtopic 855-10 and gives a definition to SEC filers, and requires SEC filers to assess for subsequent events through the issuance date of the financial statements. This amendment states that an SEC filer is not required to disclose the date through which subsequent events have been evaluated for a reporting period. The Company adopted the provisions of ASU 2010-09 in the period ended March 31, 2010.

In January 2010, the FASB issued additional disclosure requirements related to fair value measurements. The guidance requires disclosure of transfers of assets and liabilities between Level 1 and Level 2 in the fair value measurement hierarchy, including the reasons for the transfers and disclosure of major purchases, sales, issuances, and settlements on a gross basis in the reconciliation of the assets and liabilities measured under Level 3 of the fair value measurement hierarchy. The guidance is effective in interim and annual periods beginning after December 15, 2009, except for the Level 3 reconciliation disclosures which are effective for interim and annual periods beginning after December 15, 2010. We adopted the provisions for the quarter ending March 31, 2010, except for the Level 3 reconciliation disclosures included in Note 9, which we adopted in the quarter ending March 31, 2011. Adopting the disclosure requirements for the quarter ending March 31, 2010 did not have an impact on our financial position or results of operations. We do not expect adoption of the Level 3 reconciliation disclosures in 2011 to have any impact on our financial position or results of operations.

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3. Significant Customers

During the year ended December 31, 2012, purchases by four companies exceeded 10% of the total oil and natural gas sales of the Company. Purchases by Enbridge Pipeline (East Texas) LP, Shell Trading (US) Company, Texla Energy Management LLC and Eastex Crude Company accounted for approximately 17%, 14%, 13% and 12% of oil and natural gas sales, respectively. During the year ended December 31, 2011, purchases by three companies exceeded 10% of the total oil and natural gas sales of the Company. Purchases by Enbridge Pipeline (East Texas) LP, Texla Energy Management LLC and PVR Midstream LLC accounted for approximately 18%, 15% and 13% of oil and natural gas sales, respectively. During the year ended December 31, 2010, purchases by two companies exceeded 10% of the total oil and natural gas sales of the Company. Purchases by Enbridge Pipeline (East Texas) LP and PVR Midstream LLC accounted for approximately 22% and 23% of oil and natural gas sales, respectively. The Company believes that the loss of any of the purchasers above would not result in a material adverse effect on its ability to market future oil and natural gas production.

4. Property Acquisitions and Divestitures

Total costs incurred for oil and gas property acquisitions for 2012 were approximately $737.1 million, of which $145.1 million related to unproved property, $418.5 million related to proved property acquisitions, and $173.5 million related to goodwill. Total costs incurred for 2011 were approximately $396.4 million (excluding related asset retirement costs), of which approximately $31.3 million related to unproved properties, $365.1 million related to proved property acquisitions, and no goodwill acquired. Total costs incurred for gathering and processing facilities was approximately $5.7 million, net of purchase price adjustments.

On December 14, 2012, the Company closed on a Purchase and Sale Agreement for the acquisition of certain oil and gas properties in the Texas Panhandle and surrounding Oklahoma area for $657.8 million, net of purchase price adjustments. The acquisition was funded in part by $181.6 million of equity contributed by members with the remaining balance funded from the proceeds of the second lien term loan agreement. This acquisition qualified as a business combination pursuant to ASC 805. The Company recorded a fair value of $339.2 million for proved property and $145.1 million for unproved acreage. This transaction resulted in the recognition of $173.5 million of goodwill for the excess of the consideration transferred over the net assets received and represents the future economic benefits arising from assets acquired that could not be individually identified and separately recognized.. The valuation to derive the purchase price included both proved and unproved categories of reserves, expectation for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. Revenues and operating expenses recognized in the Consolidated Statement of Operations as of December 31, 2012 were $4.1 million and $0.4 million, respectively.

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4. Property Acquisitions and Divestitures (continued)

The following table summarizes the consideration paid and the amounts of the assets acquired and liabilities assumed as of the date of acquisition (in millions):

Recognized amounts of identifiable assets acquired and liabilities assumed:		
Proved properties	$	339.2
Goodwill		173.5
Unproved properties		145.1
Consideration, net of accrued purchase price adjustments	$	657.8

The unaudited pro forma results presented below have been prepared to give the effect of the acquisition discussed above on our results of operations for the years ended December 31, 2012 and 2011 as if it had been consummated on January 1, 2011. The unaudited pro forma results do not purport to represent what our actual results of operations would have been if the acquisition had been completed on such date or to project our results of operations for any future date or period.

	Year Ended December 31, 2012		Year Ended December 31, 2011	
	Actual	Pro Forma	Actual	Pro Forma
	(in thousands)			
Pro Forma (*unaudited*)				
Total revenues	$ 288,496	$ 369,412	$ 277,637	$ 315,291
Total operating expenses (1) (2)	$ 928,404	$ 737,155	$ 193,781	$ 182,338
Net income applicable to controlling interests (1) (2)	$ (700,088)	$ (427,923)	$ 17,919	$ 67,016

(1) Bargain purchase gain of $14.5 million and $99.5 million, recognized in operating expenses for 2012 and 2011, respectivly, has been excluded from actual results above.

(2) Reductions in operating expenses due to pro forma ceiling test impacts of $228.3 million and $25.7 million for 2012 and 2011, respectivly, have been included in pro forma results above.

On December 17, 2012, the Company closed on a Purchase and Sale Agreement for the acquisition of certain oil and gas properties in South Texas for $79.3 million, net of purchase price adjustments. This acquisition qualified as a business combination pursuant to ASC 805. The Company recorded a fair value of $93.7 million for proved property, which resulted in a bargain purchase gain of $14.5 million that was recorded in the current period s earnings. The valuation to derive the purchase price included both proved and unproved categories of reserves, expectation for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. There was no material amounts recognized for revenues or operating expenses in the Consolidated Statement of Operations for the year ended December 31, 2012.

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4. Property Acquisitions and Divestitures (continued)

The following table summarizes the consideration paid and the amounts of the assets acquired and liabilities assumed as of the date of acquisition (in millions):

Recognized amounts of identifiable assets acquired and liabilities assumed:		
Proved properties	$	93.8
Bargain purchase gain		(14.5)
Cash, net of accrued purchase price adjustments	$	79.3

The unaudited pro forma results presented below have been prepared to give the effect of the acquisition discussed above on our results of operations for the years ended December 31, 2012 and 2011 as if it had been consummated on January 1, 2011. The unaudited pro forma results do not purport to represent what our actual results of operations would have been if the acquisition had been completed on such date or to project our results of operations for any future date or period.

	Year Ended December 31, 2012		Year Ended December 31, 2011	
	Actual	Pro Forma	Actual	Pro Forma
	(in thousands)			
Pro Forma (*unaudited*)				
Total revenues	$ 288,496	$ 292,247	$ 277,637	$ 289,497
Total operating expenses (1) (2)	$ 928,404	$ 922,948	$ 193,781	$ 176,957
Net income applicable to controlling interests (1) (2)	$ (700,088)	$ (690,881)	$ 17,919	$ 46,603

(1) Bargain purchase gain of $14.5 million and $99.5 million, recognized in operating expenses for 2012 and 2011, respectivly, has been excluded from actual results above.

(2) Reductions in operating expenses due to pro forma ceiling test impacts of of $12.1 million and $25.7 million for 2012 and 2011, respectivly, have been included in pro forma results above.

On August 31, 2012, the Company closed on the sale of its Montana oil and gas properties for $15.8 million, net of purchase price adjustments. The sale of the Montana oil and gas properties was accounted for as an adjustment to the full cost pool with no gain or loss recognized. Concurrently with the sale of the Montana oil and gas properties, the Company closed on the sale of its controlling ownership interests in Montana gathering entities Lodge Creek Pipelines, LLC and Willow Greek Gathering, LLC for a combined $2.5 million net of purchase price adjustments. The sale of the Montana gathering entities resulted in a loss of $9.9 million that was recognized as Loss on sale of assets in the Consolidated Statement of Operations for the three and nine months ended September 30, 2012.

On May 22, 2012, the Company closed on the sale of its working interests in Utah oil and gas properties for $18.2 million, net of purchase price adjustments. The sale of the Utah oil and gas properties was accounted for as an adjustment to the full cost pool with no gain or loss recognized.

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4. Property Acquisitions and Divestitures (continued)

On September 26, 2011, the Company signed a Purchase and Sale Agreement for the acquisition of certain oil and gas properties in East Texas which closed on November 14, 2011 for $222.0 million, net of purchase price adjustments. This acquisition qualified as a business combination pursuant to ASC 805. The Company recorded a fair value of $235.1 million for proved property and $5.3 million for unproved acreage, which resulted in a bargain purchase gain of $18.4 million that was recorded in the current period s earnings. The valuation to derive the purchase price included both proved and unproved categories of reserves, expectation for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates considering a depressed natural gas market. The gain was a result of fair market value in excess of the discounted purchase price for the proved developed and undeveloped reserves and unproved acreage.

The following table summarizes the consideration paid and the amounts of the assets acquired and liabilities assumed as of the date of acquisition (in millions):

Recognized amounts of identifiable assets acquired and liabilities assumed:		
Proved developed properties	$	235.1
Unproved leasehold properties		5.3
Bargain purchase gain		(18.4)
Cash, net of accrued purchase price adjustments	$	222.0

The unaudited pro forma results presented below have been prepared to give the effect of the acquisition discussed above on our results of operations for the years ended December 31, 2011 and 2010 as if it had been consummated on January 1, 2010. The unaudited pro forma results do not purport to represent what our actual results of operations would have been if the acquisition had been completed on such date or to project our results of operations for any future date or period.

	Year Ended December 31, 2011				Year Ended December 31, 2010			
	Actual		Pro Forma		Actual		Pro Forma	
			(in thousands)					
Pro Forma (*unaudited*)								
Total revenues	$	277,637	$	317,254	$	184,556	$	243,220
Total operating expenses (1)	$	193,781	$	222,918	$	113,643	$	154,260
Net income applicable to controlling interests (1)	$	17,919	$	28,399	$	38,769	$	56,816

(1) Bargain purchase gain of $99.5 million, recognized in operating expenses, has been excluded from actual results above.

On July 5, 2011, the Company entered into an agreement to purchase oil and gas properties in East Texas which closed on August 18, 2011 for $102.6 million, net of purchase price adjustments. This acquisition qualified as a business combination pursuant to ASC 805. The Company recorded a fair value of $142.3 million for proved property and $14.8 million for unproved acreage, which resulted in a bargain purchase gain of

$54.5 million that was recorded in the current period s earnings. The valuation to derive the purchase price included both proved and unproved categories of reserves, expectation for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates considering a depressed natural gas market. The gain was a result of fair market value in excess of the discounted purchase price for the proved developed and undeveloped reserves and unproved acreage, as well as an upward shift in the forward price curve at the time of closing.

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4. Property Acquisitions and Divestitures (continued)

The following table summarizes the consideration paid and the amounts of the assets acquired and liabilities assumed as of the date of acquisition (in millions):

Recognized amounts of identifiable assets acquired and liabilities assumed:		
Proved properties	$	142.3
Unproved properties		14.8
Bargain purchase gain		(54.5)
Cash, net of accrued purchase price adjustments	$	102.6

The unaudited pro forma results presented below have been prepared to give the effect of the acquisition discussed above on our results of operations for the years ended December 31, 2011 and 2010 as if it had been consummated on January 1, 2010. The unaudited pro forma results do not purport to represent what our actual results of operations would have been if the acquisition had been completed on such date or to project our results of operations for any future date or period.

	Year Ended December 31, 2011		Year Ended December 31, 2010	
	Actual	Pro Forma	Actual	Pro Forma
	(in thousands)			
Pro Forma (*unaudited*)				
Total revenues	$ 277,637	$ 292,156	$ 184,556	$ 210,549
Total operating expenses (1)	$ 193,781	$ 202,478	$ 113,643	$ 131,252
Net income applicable to controlling interests (1)	$ 17,919	$ 23,741	$ 38,769	$ 47,153

(1) Bargain purchase gain of $99.5 million, recognized in operating expenses, has been excluded from actual results above.

On January 31, 2011 and February 8, 2011, The Company entered into agreements to purchase working interests in developed and undeveloped acreage in East Texas for $60.7 million and $11.2 million, respectively, for a total adjusted purchase price of $71.8 million, which qualified as a business combination pursuant to ASC 805. The Company recorded a fair value of $87.4 million for developed acreage, which resulted in a bargain purchase gain of $26.7 million that was recorded in the current period s earnings. The valuation to derive the purchase price included proved categories of reserves, expectation for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates considering a depressed natural gas market. The gain was a result of fair market value in excess of the discounted purchase price for both proved developed and undeveloped reserves and unproved acreage, as well as a result of an upward shift in the forward price curve at the time of closing and receipt of updated production data for the recent producing wells that improved the well economics.

The following table summarizes the consideration paid and the amounts of the assets acquired and liabilities assumed as of the date of acquisition (in millions):

Recognized amounts of identifiable assets acquired and liabilities assumed:		
Proved developed properties	$	87.4
Unproved leasehold properties		11.2
Asset retirement obligation		(0.1)
Bargain purchase gain		(26.7)
Cash, net of accrued purchase price adjustments	$	71.8

The unaudited pro forma results presented below have been prepared to give the effect of the acquisitions discussed above on our results of operations for the years ended December 31, 2011 and 2010 as if it had been consummated on January 1, 2010.

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4. Property Acquisitions and Divestitures (continued)

The unaudited pro forma results do not purport to represent what our actual results of operations would have been if these acquisitions had been completed on such date or to project our results of operations for any future date or period.

	Year Ended December 31, 2011 Actual	Year Ended December 31, 2011 Pro Forma	Year Ended December 31, 2010 Actual	Year Ended December 31, 2010 Pro Forma
	(in thousands)			
Pro Forma (*unaudited*)				
Total revenues	$ 277,637	$ 280,519	$ 184,556	$ 215,385
Total operating expenses (1)	$ 193,781	$ 194,412	$ 113,643	$ 132,848
Net income applicable to controlling interests (1)	$ 17,919	$ 20,169	$ 38,769	$ 50,393

(1) Bargain purchase gain of $99.5 million, recognized in operating expenses for 2011, has been excluded from actual results above.

On October 7, 2010, the Company entered into an agreement to purchase working interests in developed and undeveloped acreage for an adjusted purchase price of $64.5 million, which qualified as a business combination pursuant to ASC 805. Sabine recorded a fair value of $64.9 million, which resulted in a bargain purchase gain of $0.4 million that was recorded in the current period s earnings.

The following table summarizes the consideration paid and the amounts of the assets acquired and liabilities assumed as of the date of acquisition (in millions):

Proved developed and undeveloped properties	$ 48.8
Unproved leasehold properties	16.4
Asset retirement obligation	(0.3)
Bargain purchase gain	(0.4)
Cash, net of accrued purchase price adjustments	$ 64.5

The unaudited pro forma results presented below have been prepared to give effect to the acquisition discussed above on our results of operations as if it had been consummated at the beginning of the comparable period for the year ended December 31, 2009. The unaudited pro forma results do not purport to represent what our actual results of operations would have been if this acquisition had been completed on such date or to project our results of operations for any future date or period.

Year Ended
December 31, 2010

	Actual	Pro Forma
	(in thousands)	
Pro Forma (*unaudited*)		
Total revenues	$ 184,556	$ 193,240
Total operating expenses	$ 113,643	$ 118,627
Net income (loss) applicable to controlling interests	$ 38,769	$ 42,469

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4. Property Acquisitions and Divestitures (continued)

In May 2010, Sabine entered into an agreement to purchase working interests in 16,339 net undeveloped acres that are prospective for the Haynesville Shale formation in Harrison, Panola and Rusk Counties, Texas, for $42.6 million. None of the acreage was developed or proved at the time of acquisition.

During 2012, 2011 and 2010 the Company has acquired oil, natural gas and natural gas liquids properties. Acquired properties that are considered to be business combinations are recorded at their fair value. In determining the fair value of the proved and unproved properties, the Company prepares estimates of oil and natural gas reserves. The Company estimates future prices to apply to the estimated reserve quantities acquired and the estimated future operating and development costs to arrive at the estimates of future net revenues. For the fair value assigned to proved reserves, the future net revenues are discounted using a market-based weighted-average cost of capital rate determined appropriate at the time of the acquisition. To compensate for inherent risks of estimating and valuing unproved reserves, probable and possible reserves are reduced by additional risk-weighting factors.

The results of each of the acquisitions are included in the accompanying consolidated statement of operations since the respective date of purchase.

The Company incurred $16.9 million and $274.6 million in development costs, for 2012 and 2011 respectively. All development related costs were included in proved properties. The Company incurred exploration costs of $72.1 million and $0.5 million in 2012 and 2011, respectively.

The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties and otherwise if impairment has occurred. Unevaluated properties are grouped by major prospect area where individual property costs are not significant. In addition, we analyze our unevaluated leasehold and transfer to evaluated properties leasehold that can be associated with reserves, leasehold that expired in the quarter or leasehold that is not a part of our development strategy and will be abandoned.

The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2012 and the year in which the associated costs were incurred:

			Year of Acquisition		
	2012	2011	2010	Prior	Total
			(in millions)		
Leasehold acquisition cost	$ 164.3	$ 9.0	$ 54.5	$ 65.9	$ 293.7
Development costs (1)	24.1	4.3	4.6		33.0
Capitalized interest	2.1	2.2	1.8	.1	6.2
Total	$ 190.5	$ 15.5	$ 60.9	$ 66.0	$ 332.9

(1) Development costs excluded from the amortization base in accordance with full cost accounting rules.

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5. Long-Term Debt

Senior Notes

On February 12, 2010, we and our subsidiary Sabine Oil & Gas Finance Corporation, formerly NFR Energy Finance Corporation, co-issued $200 million in 9.75% senior unsecured notes due 2017 (the 2017 Notes) in a private placement to qualified institutional buyers in accordance with Rule 144A under the Securities Act of 1933 and to persons outside the United States in compliance with Regulation S of the Securities Act of 1933. The 2017 Notes bear interest at a rate of 9.75% per annum, payable semi-annually on February 15 and August 15 each year commencing August 15, 2010. The 2017 Notes were issued at 98.73% of par. In conjunction with the issuance of the 2017 Notes, the Company recorded a discount of $2.53 million to be amortized over the remaining life of the 2017 Notes utilizing the simple interest method. The remaining unamortized discount was $1.49 million and $1.85 million at December 31, 2012 and 2011, respectively. The 2017 Notes were issued under and are governed by an indenture dated February 12, 2010 between the Company, Sabine Oil & Gas Finance Corporation, the Bank of New York Mellon Trust Company, N.A. as trustee, and the Company s subsidiaries named therein as guarantors.

All of our domestic restricted subsidiaries that guarantee our senior secured revolving credit facility (other than Sabine Oil & Gas Finance Corporation) have guaranteed the 2017 Notes on a senior unsecured basis. We utilized the net proceeds from the sale to repay outstanding borrowings of $188.0 million. The Company paid $3.1 million in early termination fees associated with the repayments and expensed $1.8 million of accumulated deferred financing costs associated with the borrowings. Both the early termination fee and the amortization of deferred financing costs are included in interest expense on the statement of operations.

On April 14, 2010, we and Sabine Oil & Gas Finance Corporation issued an additional $150 million in senior notes at 9.75% due 2017. The additional notes were issued at 98.75% of par and bear interest at a rate of 9.75% per annum, payable semi-annually on February 15 and August 15 of each year commencing August 15, 2010. The additional notes were issued under the same indenture as the 2017 Notes issued on February 12, 2010. The Company recorded a discount of $1.87 million to be amortized over the remaining life of the 2017 Notes utilizing the simple interest method. The remaining unamortized discount was $1.10 million and $1.37 million at December 31, 2012 and 2011, respectively. Proceeds were used to repay outstanding borrowings, to purchase assets in East Texas, and to provide working capital for general corporate purposes in 2010.

We may redeem the 2017 Notes, in whole or in part, at any time on or after February 15, 2014, at a redemption price (expressed as a percentage of principal amount) set forth in the following table plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the twelve-month period beginning on February 15 of the years indicated below:

Year	Percentage
2014	104.875
2015	102.438
2016	100.000

We may redeem some or all of the 2017 Notes prior to February 15, 2014 at a redemption price equal to 100% of the principal amount thereof, plus accrued and unpaid interest to the date of such redemption, plus a make-whole premium equal to the greater of (1) 1% of the principal amount of such note or (2) the excess of (a) the present value at such time of (i) the redemption price of such note at February 15, 2014, plus (ii) all required interest payments due on the 2017 Notes through February 15, 2014, computed using a discount rate equal to the yield of United

States Treasury securities with a constant maturity most nearly equal to the period from the redemption date to February 15, 2014 plus 50 basis points, over (b) the principal amount of such note. Each holder of the notes will also be entitled to require us to repurchase all or a portion of its notes at a purchase price equal to 101% of the principal amount thereof, plus accrued and unpaid interest to the date of such repurchase upon a change of control.

5. Long-Term Debt (continued)

The indenture governing the 2017 Notes contains covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to incur additional indebtedness unless the ratio of our adjusted consolidated EBITDA to our adjusted consolidated interest expense over the trailing four fiscal quarters will be at least 2.0 to 1.0 (subject to exceptions for borrowings within certain limits under our Credit Facility); pay dividends or repurchase or redeem equity interests; limit dividends or other payments by restricted subsidiaries that are not guarantors to us or our other subsidiaries; make certain investments; incur liens; enter into certain types of transactions with our affiliates; and sell assets or consolidate or merge with or into other companies. However, if and for as long as the 2017 Notes have an investment grade rating from Standard & Poor s Ratings Group, Inc. and Moody s Investors Service, Inc., and no default or event of default exists under the indenture, we will not be subject to certain of the foregoing covenants.

Senior Secured Revolving Credit Facility

On November 30, 2007, the Company entered into a first lien revolving credit facility with a syndicate of banks. Through a series of redeterminations, the Company has amended and restated the Credit Facility. The most recent redetermination effective October 19, 2012, decreased the borrowing base from $570.9 million to $525 million. The next redetermination will be in April 2013. Effective April 20, 2012, the administrative agent role and outstanding balance were transferred from BNP Paribas to Wells Fargo Bank.

As of December 31, 2012, commitments under the Credit Facility are $750 million, the borrowing base was $525 million, the outstanding balance amount totaled $405 million and we were able to incur approximately $120 million of secured indebtedness under our Credit Facility. The Credit Facility s maturity date is April 7, 2016.

Subsequent to the period ended December 31, 2012, through March 31, 2013, the Company has borrowed $53 million and has repaid $152 million under our Credit Facility. As of March 31, 2013 after giving effect to the second lien term loan agreement and the net amount of borrowings and repayments, the borrowing base under the Credit Facility was $487.5 million, the outstanding amount totaled $306 million and we were able to incur approximately $181.5 million of secured indebtedness under our Credit Facility.

Borrowings made under the Credit Facility are guaranteed by first priority perfected liens and security interests on substantially all assets of Sabine and its wholly-owned domestic subsidiaries.

Interest on borrowings under the Credit Facility accrues at variable interest rates at either a Eurodollar rate or an alternate base rate (ABR). The Eurodollar rate is calculated as London Interbank Offered Rate (LIBOR) plus an applicable margin that varies from 1.75% (for periods in which Sabine has utilized less than 30% of the borrowing base) to 2.75% (for periods in which Sabine has utilized equal to or greater than 90% of the borrowing base). The ABR is calculated as the greater of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.50%, or (c) Eurodollar rate on such day (or if such day is not a business day, the immediately preceding business day) plus 1.5%. The Company elects the basis of the interest rate at the time of each borrowing. In addition, Sabine pays a commitment fee of 0.50% under the Credit Facility (quarterly in arrears) for the amount that the aggregate commitments exceed borrowings under the Credit Facility.

Under the Credit Facility, the Company may request letters of credit, provided that the borrowing base is not exceeded or will not be exceeded as a result of issuance of the letter of credit. There were no outstanding letters of credit on December 31, 2012 or December 31, 2011.

The Credit Facility requires the Company to comply with certain financial covenants to maintain (a) a current ratio, defined as a ratio of consolidated current assets (including the unused amount of the total commitments under the Credit Facility, but excluding noncash assets under ASC 815, Derivatives and Hedging (formerly Statements of Financial Accounting Standards (SFAS) 133), to consolidated current liabilities (excluding noncash obligations under ASC 815 and the current maturities under the Credit Facility, determined at the end of each quarter), of not less than 1.0 to 1.0; (b) an interest coverage ratio at the end of each quarter defined as a ratio of EBITDA (as such terms are defined in the Credit Facility) for the period of four fiscal quarters then ending to interest expense for such period of not less than 2.5 to 1.0.

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5. Long-Term Debt (continued)

In addition, the Credit Facility contains covenants that restrict, among other things, the Company s ability to incur other indebtedness, create liens, or sell its assets; merge with other entities; pay dividends; enter into hedging agreements; and make certain investments. At December 31, 2012 and December 31, 2011, Sabine was in compliance with its financial debt covenants under the Credit Facility.

Second Lien Term Loan Agreement

The Company entered into a second lien term loan facility (Second Lien) on December 14, 2012 with a maturity date of April 7, 2016. Proceeds from the Second Lien were used to acquire oil and gas properties in December 2012. As of December 31, 2012, the outstanding balance under our Second Lien was $500 million. On January, 23, 2013, the syndication was completed with additional funding of $150 million, and an outstanding balance of $650 million.

Borrowings made under the second lien term loan agreement are subordinate to the liens and security interests securing the Credit Facility.

Interest on borrowings under the Second Lien accrues at variable interest rates at either a Eurodollar rate or an alternate base rate (ABR). Effective with the close of the syndicate in January 2013, the Eurodollar rate is calculated as London Interbank Offered Rate (LIBOR) plus an applicable margin of 7.50%. The Company elects the basis of the interest rate at the time of each borrowing.

6. Member s Capital

The Company is authorized to issue one class of units to be designated as Common Units . The Units are not represented by certificates. All Common Units are issued at a price equal to $1,000 per unit.

7. Statement of Cash Flows

During the year ended December 31, 2012, the Company s noncash investing and financing activities consisted of the following transactions:

- Recognition of an asset retirement obligation for the plugging and abandonment costs related to the Company s oil and natural gas properties valued at $1.9 million.

- Recognition of bargain purchase gains of $14.5 million related to the recognition of the fair market value in excess of the consideration paid for proved developed and undeveloped reserves and undeveloped acreage.

- Changes to oil and natural gas properties of $27.5 million, included in accrued exploration and development.

- In-kind contribution of assets for an equity interest in the Company of $178.0 million.

During the year ended December 31, 2011, the Company s noncash investing and financing activities consisted of the following transactions:

- Recognition of an asset retirement obligation for the plugging and abandonment costs related to the Company s oil and natural gas properties valued at $5.7 million.

- Recognition of bargain purchase gains of $99.5 million related to the recognition of the fair market value in excess of the consideration paid for proved developed and undeveloped reserves and undeveloped acreage.

- Changes to oil and natural gas properties of $10.4 million, included in accrued exploration and development.

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7. Statement of Cash Flows (continued)

During the year ended December 31, 2010, the Company s noncash investing and financing activities consisted of the following transactions:

- Recognition of an asset retirement obligation for the plugging and abandonment costs related to the Company s oil and natural gas properties valued at $0.6 million.

- Recognition of bargain purchase gains of $0.4 million related to the recognition of the fair market value in excess of the consideration paid for proved developed and undeveloped reserves and undeveloped acreage.

- Additions to oil and natural gas properties of $23.4 million, included in accrued exploration and development.

Sabine paid $47.1 million, $41.1 million and $20.9 million for interest during 2012, 2011 and 2010, respectively.

8. Derivative Financial Instruments

The Company is exposed to risks associated with unfavorable changes in the market price of natural gas as a result of the forecasted sale of its production and uses derivative instruments to hedge or reduce its exposure to certain of these risks. During 2012, a portion of commodity derivative instruments were designated as cash flow hedges and were subject to cash flow hedge accounting under ASC 815. For the remaining derivative instruments, the Company did not elect hedge accounting for accounting purposes or did not qualify for hedge accounting treatment and, accordingly, recorded the net change in the mark-to-market valuation of these derivative instruments in the Consolidated Statement of Operations.

In December 2012, The Company entered into certain oil and natural gas swap contracts covering certain volumes of anticipated production for 2013 and 2014. These contracts were designated as cash flow hedges at the time of their execution.

In June 2012, the Company entered into certain option contracts on oil and natural gas. These included purchased natural gas puts, written natural gas puts, written natural gas calls, and written oil calls for periods from 2013 through 2016, for which a net premium was recognized. The main impact of these contracts enhanced our 2014 production coverage by creating a spread of $1.00 with our existing 2014 natural gas calls, and shifted the liability on natural gas calls out to 2016. As a result of these contracts, the Company recognized a net deferred premium liability of $5.1 million in Other long term obligations on the December 31, 2012 Consolidated Balance Sheets to be settled each month per the terms of the contract in 2014. The unamortized premium included in long term derivative assets is $5.1 million at December 31, 2012. See the table below for specific volume, timing, and pricing details regarding our designated and non designated trade positions.

In December 2011, the Company executed the sale of oil and natural gas options for which a premium was received that will be amortized as the contracts settle each month. These included written oil puts, written oil calls, and written natural gas calls. The Company used the premium received to execute natural gas swap contracts above market price. See the table below for specific volume, timing, and pricing details regarding our designated and non designated trade positions. The unamortized premium included in short term and long term derivative liabilities is $1.2 million and $16.2 million, respectively, at December 31, 2012.

During February 2011, the Company restructured its hedge portfolio through the execution of new financial commodity derivative contracts, the restructuring of certain existing derivative contracts and the liquidation of certain derivative contract positions as follows:

- The Company liquidated and settled all existing hedge contracts covering volumes for the years 2014 and 2015.

- The Company re-couponed all volumes covered by the existing 2013 swap contracts from $7.40/MMBTU to

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8. Derivative Financial Instruments (continued)

$6.0/MMBTU.

- The Company added new swap contracts of 9.6BCF at an average price of $6.17/MMBTU and 16.4BCF at an average price of $5.67/MMBTU in 2011 and 2012, respectively. Proceeds from the liquidation and re-couponing actions taken in the bullets above were used to execute the new swap contracts that were added for 2011 and 2012.

The net impact of the restructure on the fair market value of derivative instruments was $2.9 million, recognized in other expenses as a loss on derivative instruments.

The following swaps, basis swaps, costless collars and options were outstanding with associated notional volumes and contracted swap, floor, and ceiling prices that represent hedge weighted average prices for the index specified as of December 31, 2012:

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8. Derivative Financial Instruments (continued)

	Future production designated for hedge accounting 2013		2014	
Swaps - Natural Gas				
Volume (MMBTU)		42,093,731		15,550,000
Price	$	4.84	$	3.98
Swaps - Oil				
Volume (Bbls)		620,500		620,500
Price	$	89.50	$	89.13

		2013	Future production not designated for hedge accounting 2014		2015		2016	
Puts - Natural Gas (Buy)								
Volume (MMBTU) (1)				26,425,000				
Price (1)			$	4.50				
Puts - Natural Gas (Sell)								
Volume (MMBTU) (1)				26,425,000				
Price (1)			$	3.50				
Calls - Oil (Sell)								
Volume (Bbls)		200,750		200,750		200,750		
Price	$	106.36	$	106.36	$	106.36		
Calls - Natural Gas (Sell)								
Volume (MMBTU) (1)				26,425,000		21,900,000		21,960,000
Price (1)			$	5.25	$	5.25	$	5.00
Basis Swap, NYMEX - East Texas (Houston Ship Channel)								
Volume (MMBTU)		1,277,500						
Contract differential (2)		$0.11 - $0.15						
Basis Swap, NYMEX - TEXOK (NGLP)								
Volume (MMBTU)		3,869,000						
Contract differential (2)		$0.21 - $0.25						

(1) The Company purchased and sold additional put options on a like amount of natural gas volume as the natural gas calls. The addition of the put contracts establishes a derivative contract structure which will require the Company to make payment to the counterparty if the settlement price for any settlement period is above the call price. The Company will be entitled to payment from the counterparty should the settlement price for any settlement period be below the purchased put price ($4.50) but above the sold put price ($3.50). If the settlement price is less than the sold put price, the Company is entitled to a net payment from the counterparty for the spread between the purchased and sold put option prices ($1).

(2) Basis swaps settle based on NYMEX pricing minus a differential, which is then compared to Inside Federal Energy Regulatory Commission (FERC) for the index on which volumes are being hedged.

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8. Derivative Financial Instruments (continued)

For our energy commodity derivative instruments that were designated as cash flow hedges, the portion of the change in the value of derivative instruments that is effective in offsetting changes in expected cash flows (the effective portion) is reported as a component of Accumulated other comprehensive income on our Consolidated Balance Sheets, but only to the extent that it can later offset the undesired changes in expected cash flows during the period in which the hedged cash flows affect earnings. To the contrary, the portion of the change in the value of derivative instruments that is not effective in offsetting changes in expected cash flows (the ineffective portion), as well as any component excluded from the assessment of the effectiveness of the derivative instruments, is required to be recognized currently in earnings. The Company excludes time value associated with costless collars from the assessment of effectiveness.

The Company recorded a short term and a long term derivative asset of $54.9 million and $6.7 million, respectively, and recorded a short term and a long term derivative liability of $3.9 million and $18.0 million, respectively, related to the fair value of the derivative instrument s prices on remaining volumes as of December 31, 2012 after application of ASC 820, Fair Value Measurements.

The table below provides data about the carrying values of derivatives instruments as of December 31, 2012.

		Assets Derivatives			
		December 31, 2012		December 31, 2011	
		(in thousands)			
Derivatives designated as hedging instruments		Fair Value			
Current	Derivative Instruments	$	54,302	$	92,760
Long term	Derivative Instruments				41,007
Total derivatives designated as hedging instruments		$	54,302	$	133,767

		Liabilities Derivatives			
		December 31, 2012		December 31, 2011	
		(in thousands)			
Derivatives designated as hedging instruments		Fair Value			
Current	Derivative Instruments	$	(2,101)	$	
Long term	Derivative Instruments		(2,653)		
Total derivatives not designated as hedging instruments		$	(4,754)	$	

		Assets Derivatives			
		December 31, 2012		December 31, 2011	
		(in thousands)			
Derivatives not designated as hedging instruments		Fair Value			
Current	Derivative Instruments	$	779	$	
Long term	Derivative Instruments		16,189		6
Total derivatives not designated as hedging instruments		$	16,968	$	6

		Liabilities Derivatives	
		December 31, 2012	December 31, 2011
		(in thousands)	

Derivatives not designated as hedging instruments		**Fair Value**	
Current	Derivative Instruments	$ (2,000)	$ (1,978)
Long term	Derivative Instruments	(24,822)	(21,502)
Total derivatives not designated as hedging instruments		$ (26,822)	$ (23,480)

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8. Derivative Financial Instruments (continued)

The following tables summarize the cash flow hedge gains and losses and their location on the Consolidated Balance Sheets as of December 31, 2012 2011, and 2010 and Consolidated Statement of Operations for the years ended December 31, 2012, 2011 and 2010:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain Recognized in Other Comprehensive Income (OCI)	Location of Gain Reclassified from Accumulated OCI into Operating Income	Amount of Gain Reclassified from Accumulated OCI into Operating Income (in thousands)	Location of Gain (loss) in Other Income on Ineffective Hedges	Amount of Gain (loss) Recognized in Income (Ineffective portion and Amount Excluded from Effectiveness Testing)
For the Year Ended December 31, 2012:					
Derivative Instruments	$ 39,581	Gain on derivative instruments	$ 107,374	Loss on derivative instruments	$ (16,424)
Total	$ 39,581		$ 107,374		$ (16,424)
For the Year Ended December 31, 2011:					
Derivative Instruments	$ 97,632	Gain on derivative instruments	$ 72,517	Gain on derivative instruments	$ 409
Total	$ 97,632		$ 72,517		$ 409
For the Year Ended December 31, 2010					
Derivative Instruments	$ 105,629	Gain on derivative instruments	$ 55,305	Loss on derivative instruments	$ (533)
Total	$ 105,629		$ 55,305		$ (533)

The following table summarizes the location in the Consolidated Statement of Operations and amounts of gains and losses on derivative instruments that do not qualify for hedge accounting for the year ended December 31, 2012, 2011, and 2010:

Derivatives Not Designated as Hedging Instruments	Location of Gain (loss) Recognized in Income on Derivatives	December 31, 2012	Recognized in Income on Derivatives for the Year Ended December 31, 2011 (in thousands)	December 31, 2010
Derivative Instruments	Gain (loss) on Derivative Instruments	$ 6,112	$ (26,208)	$ (1,121)

The consolidated Accumulated other comprehensive income balance was $63.0 million as of December 31, 2012, and $130.8 million as of December 31, 2011. Approximately $44.8 million of this total accumulated gain associated with commodity price risk management activities as of December 31, 2012 is expected to be reclassified into earnings during the next twelve months. Of the $44.8 million expected to the reclassified into earnings through December 31, 2013, $23.7 million is associated with settlements on contracts for future production designated for hedge accounting and $21.1 million is associated with our February 2011 hedge portfolio restructure.

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9. **Fair Value Measurements**

As discussed in Note 8, the Company utilizes derivative instruments to hedge against the variability in cash flows associated with the forecasted sale of its anticipated future natural gas production. The Company generally hedges a substantial, but varying, portion of anticipated natural gas production for the next 12 to 60 months. These derivatives are carried at fair value on the Consolidated Balance Sheets.

As defined in ASC 820, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs. ASC 820 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement).

The three levels of the fair value hierarchy defined by ASC 820 are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, marketable securities and listed equities.

Level 2 Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category generally include non-exchange-traded derivatives such as commodity swaps, basis swaps, options, and collars.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value.

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9. Fair Value Measurements (continued)

The following table sets forth, by level, within the fair value hierarchy, the Company s financial assets and liabilities that were accounted for at fair value as of December 31, 2012 and 2011. As required by ASC 820, financial assets and liabilities are classified in their entirety based on 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 requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Recurring Fair Value Measures (in millions)			
	Level 1	Level 2	Level 3	Total
As of December 31, 2012				
Derivative Assets	$	$ 61.6	$	$ 61.6
Derivative Liabilities		(21.9)		(21.9)
Total	$	$ 39.7	$	$ 39.7

	Level 1	Level 2	Level 3	Total
As of December 31, 2011				
Derivative Assets	$	$ 127.8	$	$ 127.8
Derivative Liabilities		(17.5)		(17.5)
Total	$	$ 110.3	$	$ 110.3

Derivatives listed above include commodity swaps, basis swaps, put and call options and collars that are carried at fair value. The fair value amounts on the Consolidated Balance Sheets associated with the Company s derivatives resulted from Level 2 fair value methodologies, that is, the Company is able to value the assets and liabilities based on observable market data for similar instruments. The amounts above include the impact of netting assets and liabilities with counterparties with which the right of offset exists.

The observable data includes the forward curve for commodity prices and interest rates based on quoted markets prices and prospective volatility factors related to changes in commodity prices, as well as the impact of our non-performance risk of the counterparties which is derived using credit default swap values.

The Company measures fair value of its long term debt based on a Level 2 methodology using quoted market prices with consideration given to the effect of the Company s credit risk. The carrying value of the Company s credit facilities approximate fair value based on current rates applicable to similar instruments. The following table outlines the fair value of our 2017 Notes as of December 31, 2012 and 2011:

	December 31, 2012	December 31, 2011
	(in thousands)	
2017 Senior Notes		
Carrying Value	$ 347,411	$ 346,782

Fair Value	$	326,050	$	323,456

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10. Related-Party Transactions

As part of our ongoing operations, we have previously contracted with affiliates of Nabors Industries to secure drilling rigs and other services for the oil and natural gas well activity we have undertaken. Amounts paid to affiliates of Nabors Industries under these agreements totaled $41.0 million and $87.7 million, for the years ended December 31, 2012 and 2011, respectively, and the Company recognized a liability on our Consolidated Balance Sheets as of December 31, 2012 and 2011 of $3.6 million and $12.1 million, respectively, for these services.

On December 13, 2012, First Reserve acquired Nabors equity interest in Holdings. In this transaction, Holdings agreed, among other things, to enter into service arrangements with affiliates of Nabors, and to make certain deferred and contingent payments to Nabors for the equity interests sold. As part of these arrangements, Nabors and Holdings entered into a Committed Oilfield Services Agreement (the Services Agreement), under which Holdings agreed to award to Nabors service contracts with revenues of no less than 20% and 75% of our gross spend on hydraulic fracturing services and drilling and directional services, respectively, through December 13, 2016. If at any yearly anniversary of the execution of the Services Agreement, Holdings has failed to meet the revenue commitment for the previous 12-month period and Nabors has complied with its service obligations under the Services Agreement, Holdings will be required to pay Nabors an amount equal to the revenue shortfall multiplied by 40%. Holdings will cause the Company to fulfill its obligations under the Services Agreement.

The Company may be requested by Holdings to make a distribution of $10 million to Holdings, on or before June 30, 2013, in order for Holdings to satisfy its obligation to Nabors in conjunction with the sale of Nabors equity interest.

Our arrangements with Nabors Industries and its affiliates are on terms that we believe to be no less favorable to us than those we could have obtained from unaffiliated parties.

Sabine paid $0.8 million during 2010 to Smith International, Inc. (Smith), an oil and natural gas services company, for services provided. A member of the Company s board of representatives was the Chief Executive Officer, President, and Chief Operating Officer of Smith through August of 2010.

11. Commitments

The Company leases approximately 55,000 square feet of office space in downtown Houston, Texas, under a lease, which was amended effective May 1, 2013 to terminate on April 30, 2016. The average rent for this space over the life of the lease is approximately $1.3 million per year. The Company has an option to extend its lease term for an additional 60 months. As of December 31, 2012, total future commitments are $5.3 million.

The Company leases approximately 11,000 square feet of office space in downtown Denver, Colorado. The lease terminates on August 31, 2014 and the Company has the option to extend its lease term for an additional 60 months. This lease is sub leased out with proceeds to offset the rent commitments. The average rent for this space over the life of the lease is approximately $0.3 million per year. As of December 31, 2012 total future commitments are $0.5 million.

The Company leases various office and production equipment. As of December 31, 2012, total future commitments are $0.7 million. The majority of our operating leases continue with a month to month lease term after initial contractual obligations have expired.

As of December 31, 2012 total contracted future commitments to Nabors for oilfield services are 98.3 million.

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11. Commitments (continued)

As of December 31, 2012, future minimum commitments were as follows:

	Payments due by period For the Year Ended December 31,						
	2013	2014	2015	2016	2017	Thereafter	Total
				(in millions)			
Senior secured revolving credit facility (1)	$	$	$	$ 405.0	$	$	$ 405.0
Second Lien senior secured revolving credit facility (1)				650.0			650.0
2017 Senior Notes	34.1	34.1	34.1	34.1	366.8		503.2
Drilling rig commitments (2)	28.6	21.4	28.5	19.8			98.3
Office and equipment leases	2.3	2.0	1.7	0.5			6.5
Other	0.4	0.6	0.1	0.1			1.2
Total	$ 65.4	$ 58.1	$ 64.4	$ 1,109.5	$ 366.8	$	$ 1,664.2

(1) Includes outstanding principal amounts at December 31, 2012. This table does not include future commitment fees, interest expense or other fees on these facilities because they are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged.

(2) At December 31, 2012, we had eight drilling rigs under contracts, five of which expire in 2013. Any other rig performing work for us is doing so on a well-by-well basis and therefore can be released without penalty at the conclusion of drilling on the current well. These types of drilling obligations have not been included in the table above. The values in the table represent the gross amounts that we are committed to pay. However, we will record in our financials our proportionate share based on our working interest.

Rent expense was approximately $1.4 million, $1.6 million and $1.2 million for the years ended December 31, 2012, 2011 and 2010, respectively.

As is customary in the oil and natural gas industry, the Company may at times have commitments in place to reserve or earn certain acreage positions or wells. If the Company does not pay such commitments, the acreage positions or wells may be lost.

The Company is at risk of lawsuits arising in the ordinary course of our business. In Management s opinion, the Company is not currently involved in any legal proceedings which, individually or in aggregate, could have a material effect on the financial condition, operations or cashflows of the Company.

12. Employee Benefit Plans

The Company co-sponsors a 401(k) tax deferred savings plan (the Plan) and makes it available to employees. The Plan is a defined contribution plan, and the Company may make discretionary matching contributions of up to 6% of each participating employee s compensation to the Plan. The contributions made by the Company totaled approximately $905,000, $845,000 and $643,000 during the years ended December 31, 2012, 2011 and 2010, respectively.

13. Subsequent Events

Management has evaluated subsequent events through March 31, 2013, which represents the date the consolidated financial statements were issued.

Effective March 1, 2013, the Company executed additional commodity option contracts covering portions of our anticipated 2014 oil production. The Company did not pay or receive any premium related to these contracts, which included both purchased and written call options as well as written put options. These transactions will not be designated for hedge accounting, with mark to market changes in fair value recognized currently in earnings.

On March 28, 2013, the Company entered into a joint development agreement with a third party which provides for the sale of 50% of the Company s interest in four producing Haynesville wells and the expected completion of 15 additional drilled but uncompleted Haynesville wells during the next two years. The 15 drilled but uncompleted wells are divided into two tranches. Under the terms of the agreement the Company s interest in the drilled but uncompleted wells will be carried 100% by the third party until the wells are completed to production or total capital cost to the third party exceeds approximately $60 million. Upon funding of the completion costs of each drilled but uncompleted wells, the third party will receive an assignment of 50% of the Company s working interest in the wells. Upon completion of each tranche, the third party will receive an assignment of the Company s interests in the undeveloped acreage in the associated units. The Company will continue to operate all wells under the terms of the agreement and associated joint operating agreements.

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SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The following supplemental information regarding our natural gas and oil producing activities is presented in accordance with the requirements of Section 932-235-50 of the ASC.

Costs Incurred

The costs incurred in oil and natural gas acquisitions, exploration and development activities were as follows:

	For the Year Ended December 31, 2012	2011 (in thousands)	2010
Property acquisition costs, proved (1)	$ 435,715	$ 466,874	$ 60,252
Property acquisition costs, unproved (1)	145,126	28,663	68,758
Exploration and extension well costs	72,065	507	218
Development costs	16,900	274,631	238,850
Asset retirement costs	1,887	5,693	595
Total Costs	$ 671,693	$ 776,368	$ 368,673

(1) Property acquisition costs for the year ended December 31, 2012 includes bargain purchase gain of $14.5 million allocated to proved property acquisition costs and December 31, 2011 includes bargain purchase gains of $79.4 million allocated to proved property acquisition costs and $20.1 million allocated to unproved property acquisition costs.

Capitalized Costs

The capitalized costs in oil and natural gas properties were as follows:

	For the Year Ended December 31, 2012	2011 (in thousands)	2010
Proved properties	$ 2,839,900	$ 2,292,875	$ 1,506,565
Unproved properties	332,898	208,230	218,172
	3,172,798	2,501,105	1,724,737
Accumulated depletion, depreciation and amortization	(1,839,973)	(1,029,535)	(925,874)
Net capitalized costs	$ 1,332,825	$ 1,471,570	$ 798,863

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Results of Operations

Results of operations for oil and natural gas producing activities, which exclude processing and other activities, corporate general and administrative expenses, and straight-line depreciation expense on non oil and gas assets, were as follows:

	For the Year Ended December 31, 2012	2011 (in thousands)	2010
Revenues	$ 181,098	$ 204,989	$ 132,062
Gain on derivative instruments	107,374	72,517	51,104
Operating costs:			
Lease operating expenses	41,011	27,113	18,637
Workover expenses	2,638	2,903	848
Marketing, gathering, transportation and other	21,167	19,717	13,730
Production and ad valorem taxes	4,400	7,775	5,483
Depletion, depreciation and amortization	92,369	77,932	48,685
Impairments	718,070	25,729	
Results of operations	$ (591,183)	$ 116,337	$ 95,783

Oil and Natural Gas Reserves and Related Financial Data

Users of this information should be aware that the process of estimating quantities of proved and proved developed natural gas and crude oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir also may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates may occur from time to time.

The following tables set forth our total proved reserves and the changes in our total proved reserves. These reserve estimates are based in part on reports prepared by Miller and Lents, Ltd. (Miller and Lents), independent petroleum engineers, utilizing data compiled by us. In preparing its reports, Miller and Lents evaluated properties representing all of our proved reserves at December 31, 2012, 2011 and 2010. Our proved reserves are located onshore in the United States. There are many uncertainties inherent in estimating proved reserve quantities, and projecting future production rates and the timing of future development expenditures. In addition, reserve estimates of new discoveries are more imprecise than those of properties with production history. Accordingly, these estimates are subject to change as additional information becomes available. Proved reserves are the estimated quantities of natural gas, natural gas liquids and oil that geoscience and engineering data demonstrate with reasonable certainty to be economically producible in future years from known oil and natural gas reservoirs under existing economic conditions, operating methods and government regulations at the end of the respective years. Proved developed reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods.

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Proved reserves as of December 31, 2012 and 2011 were estimated using the average of the historical unweighted first-day-of-the-month prices of oil and natural gas for the prior twelve months as required under new SEC rules. The average of the historical unweighted first-day-of-the-month prices for the prior twelve month periods ended December 31, 2012 and 2011 were $2.76 and $4.12, respectively, for natural gas. The average of the historical unweighted first-day-of-the-month prices for the prior twelve month periods ended December 31, 2012 and 2011 were $94.71 and $96.19, respectively, for oil. The average of the historical unweighted first-day-of-the-month prices for the prior twelve months as of March 2012 is $2.95 for gas and $92.63 for oil, and the future prices actually received may materially differ from current prices or the prices used in making the reserve estimates impacting the amount of proved developed and proved undeveloped reserves as of December 31, 2012. With respect to future development costs and operating expenses, the Company derived estimates using the current cost environment at year end, which is consistent with current SEC rules.

Estimated Proved Reserves	**Natural Gas (Bcf)**	**NGLS (BBLS)**	**Oil (BBLS)**	**Natural Gas Equivalents (Bcfe)**
December 31, 2009	938.4	5.9	4.6	1,002.0
Revisions - Performance	(127.1)	4.4	(0.9)	(106.0)
Revisions - SEC Rule Revision (1)	(121.1)	(0.5)		(124.3)
Revisions - Pricing	8.8	0.1		9.4
Extensions, Additions and Discoveries	218.1	0.8	0.5	226.2
Production	(24.8)	(0.4)	(0.1)	(28.2)
Purchases in Place (2)	220.8	0.9	0.8	230.3
Sales in Place	(2.1)		(0.1)	(2.7)
December 31, 2010	1,111.0	11.2	4.8	1,206.7
Revisions - Performance	(101.2)	(5.0)	0.5	(128.2)
Revisions - SEC Rule Revision (1)	(590.2)	(0.2)	(3.6)	(613.0)
Revisions - Pricing	(28.8)	(0.4)	0.3	(29.4)
Extensions, Additions and Discoveries	207.1	5.1	1.3	245.7
Production	(39.0)	(0.2)	(0.7)	(44.3)
Purchases in Place (2)	611.1	15.5	3.3	723.9
Sales in Place				
December 31, 2011	1,170.0	26.0	5.9	1,361.4
Revisions - Performance	(43.4)	(3.2)	(0.4)	(65.0)
Revisions - SEC Rule Revision (1)	(359.0)	(8.7)	(1.5)	(420.1)
Revisions - Pricing	(101.9)	(0.3)	(0.3)	(106.0)
Extensions, Additions and Discoveries	2.6	0.4	2.2	18.0
Production	(41.1)	(0.9)	(0.3)	(48.6)
Purchases in Place (2)	117.5	16.2	10.5	277.8
Sales in Place	(35.7)	(0.1)	(0.1)	(36.7)
December 31, 2012	709.0	29.4	16.0	980.8
Estimated Proved Developed Reserves				
December 31, 2010	295.6	4.6	1.5	332.6
December 31, 2011	515.0	10.3	2.4	591.2
December 31, 2012	415.0	10.2	3.8	499.0

(1) In 2011 and 2012, we had negative revisions of 623.4 Bcfe and 420.1 Bcfe, respectively, which was primarily the result of proved undeveloped reserves being reclassified to non-proved status for adherence with the SEC 5 year guidance for recording proved reserves.

(2) Attributable to the purchase of oil and gas properties in East Texas as described in Note 4 in the Notes to Consolidated Financial Statements .

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information was developed utilizing procedures prescribed by ASC 932, *Disclosures about Oil and Gas Producing Activities.* The information is based on estimates prepared by our petroleum engineering staff. The standardized measure of discounted future net cash flows should not be viewed as representative of the current value of our proved oil and natural gas reserves. It and the other information contained in the following tables may be useful for certain comparative purposes, but should not be solely relied upon in evaluating us or our performance.

In reviewing the information that follows, we believe that the following factors should be taken into account:

- future costs and sales prices will probably differ from those required to be used in these calculations;
- actual production rates for future periods may vary significantly from the rates assumed in the calculations;
- a 10% discount rate may not be reasonable relative to risk inherent in realizing future net oil and natural gas revenues.

Under the standardized measure, future cash inflows were estimated by using the average of the historical unweighted first-day-of-the-month prices of oil and natural gas for the prior twelve month periods ended December 31, 2011, 2010 and 2009. Future cash inflows do not reflect the impact of open hedge positions. Future cash inflows were reduced by estimated future development and production costs based on year end costs in order to arrive at net cash flows before tax. Use of a 10% discount rate and year-end prices and costs are required by ASC 932.

In general, management does not rely on the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible outcomes.

The standardized measure of discounted future net cash flows from our estimated proved oil and natural gas reserves follows:

	For the Year Ended December 31,		
	2012	**2011**	**2010**
	(in thousands)		
Future cash inflows	$ 4,615,745	$ 6,724,283	$ 5,807,655
Less related future:			
Production costs	(1,413,634)	(2,020,736)	(1,513,149)

Development costs		(1,055,357)		(1,326,857)		(1,708,651)
Future net cash inflows		2,146,754		3,376,690		2,585,855
10% annual discount for estimated timing of cash flows (1)		(1,236,961)		(2,207,421)		(2,000,181)
Standardized measure of discounted future net cash flows	$	909,793	$	1,169,269	$	585,674

(1) The high effective discount factor is attributable to the negative present value factor, which is due to the addition of proved undeveloped properties that require a large amount of development costs. Additionally, these costs are weighted heavily in the first five years.

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A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved natural gas and crude oil reserves follows:

	For the Year Ended December 31, 2012	2011 (in thousands)	2010
Beginning Balance	$ 1,169,269	$ 585,674	$ 106,415
Revisions of previous estimates			
Changes in prices and costs	(275,429)	(41,896)	296,445
Changes in quantities (1)	(278,731)	40,535	154,218
Additions to proved reserves	35,351	168,123	40,663
Purchases of reserves	492,410	527,760	10,960
Sales of reserves	(21,815)		(2,907)
Accretion of discount	116,927	58,567	10,642
Sales of oil and gas, net	(111,814)	(147,481)	(93,364)
Change in estimated future development costs	(164,471)	(102,647)	(113,582)
Previously estimated development costs incurred	29,068	88,980	139,109
Changes in rate of production and other, net	(80,972)	(8,346)	37,075
Net change	(259,476)	583,595	479,259
Ending Balance	$ 909,793	$ 1,169,269	$ 585,674

This decline is primarily due to natural gas price decline and the reclassification of proved natural gas reserves to unproved under the SEC five-year rule as a consequence of our decision to refocus our future development capital towards our more oil-weighted properties.