SANDRIDGE ENERGY INC
Form 8-K
April 02, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the

Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): April 2, 2012

SANDRIDGE ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**1-33784**	**20-8084793**
(State or other jurisdiction	**(Commission**	**(I.R.S. Employer**

of incorporation)	**File Number)**	**Identification No.)**

123 Robert S. Kerr Avenue

Oklahoma City, Oklahoma	**73102**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (405) 429-5500

Not Applicable

Former name or former address, if changed since last report

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

¨ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

¨ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

¨ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

¨ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Item 7.01 Regulation FD Disclosure.

As previously reported, on February 1, 2012, SandRidge Energy, Inc. (the Company) and Dynamic Offshore Holding, LP (the Seller) entered into an Equity Purchase Agreement (the Equity Purchase Agreement), pursuant to which the Company will acquire 100% of the outstanding equity interests of Dynamic Offshore Resources, LLC, a Delaware limited liability company and wholly owned subsidiary of Seller (Dynamic). The Equity Purchase Agreement provides that, at the closing, the Company will pay to the Seller 73,961,554 shares of Company common stock and $681,828,337 in cash. Consummation of the transaction is subject to customary conditions, including the absence of any material adverse effect relating to Dynamic. The Company anticipates that the closing will occur during the quarter ended June 30, 2012.

This Current Report on Form 8-K is being furnished to provide additional information about the Company and Dynamic. It includes Dynamic s audited historical financial statements for the three years ended December 31, 2011, as well as audited historical financial statements for the two years ended December 31, 2010 of certain oil and natural gas interests in the Gulf of Mexico (the XTO Properties) that Dynamic acquired in 2011 from Exxon Mobil Corporation, and Dynamic s unaudited pro forma condensed statement of operations for the year ended December 31, 2011 showing the effects of Dynamic s acquisition of the XTO Properties. *See* Index to Financial Statements. Unless otherwise specifically stated, the information included in this Current Report on Form 8-K does not include information related to our pending acquisition of Dynamic.

Dynamic is an oil and natural gas exploration, development and production company with operations in the Gulf of Mexico. As of December 31, 2011, Dynamic s estimated net proved reserves were 62.5 MMBoe, of which 51% was oil and 81% were proved developed, with an associated PV-10 of approximately $1.895 billion, based on SEC pricing of $96.19 per Bbl for oil and $4.118 per MMBtu for natural gas. During February 2012, Dynamic s properties had aggregate average net daily production of approximately 25,500 Boe per day. The oil and gas reserve estimates for Dynamic are based on a December 31, 2011 reserve report prepared by Netherland, Sewell & Associates, Inc., an independent petroleum engineer.

As of December 31, 2011, Dynamic had interests in approximately 295 net productive wells and over 217 offshore oil and gas leases in federal and state waters of the Gulf of Mexico, representing approximately 731,600 gross (423,500 net) acres. Dynamic s properties are predominantly located in water depths of less than 300 feet. In addition, Dynamic owns a 49% interest in and operates the deepwater Bullwinkle field and associated platform, located in approximately 1,350 feet of water. Similar to Dynamic s shallow water properties, the Bullwinkle field produces from a fixed-leg platform utilizing surface wellheads and blowout preventers and, consequently, is not subject to recent regulations instituted for deepwater drilling.

Pro forma financial information showing our results of operations and financial condition as of and for the year ended December 31, 2011 on a pro forma basis giving effect to the Dynamic acquisition is not yet available. We plan to file such unaudited pro forma financial information by mid-April. We expect that, on a pro forma basis, the Dynamic acquisition will be accretive to our cash flows from operations and that pro forma EBITDA for the year ended December 31, 2011 will approximate the combined amounts of our pro forma EBITDA and Dynamic s pro forma EBITDAX for that period. In

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preparing such unaudited pro forma financial information, we will make a number of adjustments to Dynamic s historical financial results to reflect the acquisition and its effects. These adjustments are expected to include, but not be limited to, the following:

- The unaudited pro forma balance sheet will reflect adjustments to the historical book values of Dynamic s assets and liabilities as of December 31, 2011 to their estimated fair values, in accordance with acquisition accounting. The fair value of Dynamic s oil and natural gas properties will be estimated using a discounted cash flow model, with future cash flows estimated based upon oil and gas reserve quantities and forward strip oil and natural gas prices. Any difference between the value of consideration given and the fair market value of net assets acquired and liabilities assumed will be reflected as either goodwill (excess consideration given over fair value of net assets acquired and liabilities assumed) or a bargain purchase gain (excess fair value of net assets acquired and liabilities assumed over consideration given).

- Liabilities assumed upon our acquisition of Dynamic will include asset retirement obligations associated with Dynamic s oil and natural gas properties. Asset retirement obligations represent estimates of costs to plug, abandon and remediate oil and natural gas properties at the end of their productive lives, in accordance with applicable state laws. Retirement obligations associated with Dynamic s properties are higher than those associated with our properties due to the offshore location of Dynamic s operations.

- Because we use the full cost method of accounting for costs related to oil and natural gas properties and Dynamic uses the successful efforts method of accounting, we will need to adjust various line items in Dynamic s historical statement of operations to present such statements as if the full cost method of accounting had been used throughout the periods presented. As a result, we expect that certain operating costs of Dynamic that were charged to expense, such as unsuccessful exploration drilling costs, geological and geophysical costs, delay rental on leases, and abandonment costs, will not be deducted in the calculation of pro forma combined net income or loss.

- The pro forma financial statements will reflect the issuance of additional long-term debt and the associated pro forma additional interest expense related to the application of proceeds to fund the cash portion of the Dynamic purchase price.

Pro forma financial information, including Dynamic s pro forma EBITDAX for the year ended December 31, 2011, is necessarily illustrative only and does not purport to present what our results of operations and financial condition would have been had the Dynamic acquisition actually occurred on or before December 31, 2011.

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SUMMARY HISTORICAL CONSOLIDATED AND PRO FORMA FINANCIAL DATA

Summary Historical Consolidated and Pro Forma Condensed Financial Data SandRidge

The following table presents our summary historical consolidated financial data and summary unaudited pro forma condensed statement of operations data for the periods shown. The summary historical consolidated financial data as of December 31, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009 has been derived from our audited consolidated financial statements for those dates and periods. The following summary historical financial data should be read in conjunction with Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations and our historical consolidated financial statements and related notes thereto included in our 2011 Annual Report on Form 10-K, as amended. The summary unaudited pro forma condensed statement of operations data for the year ended December 31, 2011 have been derived from our unaudited pro forma condensed financial statements included in a Current Report on Form 8-K, which is being filed on the date hereof. The summary unaudited pro forma condensed statement of operations data does not give effect to the Dynamic acquisition. You should read the following summary unaudited pro forma statement of operations data in conjunction with the complete unaudited pro forma condensed financial statements and the related notes thereto.

The summary unaudited pro forma condensed statement of operations data reflects our historical results for the year ended December 31, 2011 adjusted on a pro forma basis to give effect to (i) our proposed conveyance of royalty interests in certain oil and natural gas properties located in northern Oklahoma and southern Kansas to the SandRidge Mississippian Trust II (the Trust) in connection with the Trust s initial public offering, (ii) the sale of certain producing properties located in eastern Texas in November 2011 and (iii) our conveyance of royalty interests in certain oil and natural gas properties located in Andrews County, Texas to SandRidge Permian Trust in August 2011. The summary unaudited pro forma condensed financial information also adjusts our historical results to give effect to final adjustments recorded in 2011 with respect to our July 2010 acquisition of Arena Resources, Inc., as if they had occurred prior to 2011. We refer to the transactions giving rise to the pro forma adjustments collectively as the SandRidge Transactions. The summary unaudited pro forma condensed financial information does not include our receipt of the proceeds of the Trust s public offering, which we will receive as consideration for the conveyance of royalty interests to the Trust.

The summary unaudited pro forma condensed statement of operations data have been presented for illustrative purposes only and do not purport to present what our results of operations and financial condition would have been had these transactions actually occurred on the relevant dates, nor do they project our results of operations for any future period or our financial condition at any future date. We therefore caution you not to place undue reliance on the following summary unaudited pro forma statement of operations data.

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	Pro Forma	Historical		
		Years Ended December 31,		
	2011	2011	2010	2009
		(in thousands)		
Statement of Operations Data:[1]				
Revenues	$ 1,375,678	$ 1,415,213	$ 931,736	$ 591,044
Expenses:				
Production	309,367	322,877	237,863	169,880
Production taxes	44,850	46,069	29,170	4,010
Drilling and services	65,654	65,654	22,368	28,380
Midstream and marketing	66,007	66,007	90,149	80,608
Depreciation and depletion oil and natural gas	320,674	326,614	275,335	176,027
Depreciation and amortization other	53,630	53,630	50,776	50,865
Impairment	2,825	2,825		1,707,150
General and administrative	150,143	148,643	179,565	100,256
(Gain) loss on derivative contracts	(44,075)	(44,075)	50,872	(147,527)
(Gain) loss on sale of assets	(2,044)	(2,044)	2,424	26,419
Total expenses	967,031	986,200	938,522	2,196,068
Income (loss) from operations	408,647	429,013	(6,786)	(1,605,024)
Other income (expense):				
Interest income	240	240	296	375
Interest expense	(234,440)	(237,572)	(247,738)	(185,691)
Loss on extinguishment of debt	(38,232)	(38,232)		
Income from equity investments				1,020
Other income, net	970	3,122	2,558	7,272
Total other expense	(271,462)	(272,442)	(244,884)	(177,024)
Income (loss) before income taxes	137,185	156,571	(251,670)	(1,782,048)
Income tax expense (benefit)	377	(5,817)	(446,680)	(8,716)
Net income (loss)	$ 136,808	$ 162,388	$ 195,010	$ (1,773,332)
Less: net income attributable to noncontrolling interest	95,336	54,323	4,445	2,258
Net income (loss) attributable to SandRidge Energy, Inc.	$ 41,472	$ 108,065	$ 190,565	$ (1,775,590)

(1) SandRidge historical and pro forma information was prepared using the full cost method of accounting.

	As of December 31,	
	2011	2010
	(in thousands)	
Balance Sheet Data (as of the end of the period):		
Cash and cash equivalents	$ 207,681	$ 5,863
Property, plant and equipment, net	$ 5,389,424	$ 4,733,865
Total assets	$ 6,219,609	$ 5,231,448
Total debt	$ 2,814,176	$ 2,909,086
Total equity	$ 2,548,950	$ 1,547,483
Total liabilities and equity	$ 6,219,609	$ 5,231,448

	Years Ended December 31, 2011	2010 (in thousands)	2009
Cash Flow Data:			
Net cash provided by operating activities	$ 475,485	$ 390,128	$ 311,559
Net cash used in investing activities	$ (918,860)	$ (962,753)	$ (1,247,059)
Net cash provided by financing activities	$ 645,193	$ 570,627	$ 942,725
Other Financial Data:			
EBITDA[(a)]	$ 726,310	$ 309,339	$ (1,371,277)
Pro forma EBITDA[(b)]	$ 656,839	n/a	n/a

(a) EBITDA is a non-GAAP financial measure. We define EBITDA as net income (loss) before income tax expense (benefit), interest expense and depreciation, depletion and amortization.

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EBITDA is a supplemental financial measure used by our management and securities analysts, investors, lenders, rating agencies and others who follow the industry as an indicator of our ability to internally fund exploration and development activities and to service or incur additional debt. EBITDA allows us to compare our operating performance and return on capital with those of other companies without regard to financing methods and capital structure. EBITDA should not be considered in isolation or as a substitute for net income, operating income or any other measure of financial performance prepared in accordance with generally accepted accounting principles. EBITDA excludes some, but not all, items that affect net income and operating income and we may define EBITDA differently than other companies. Therefore, our EBITDA may not be comparable to similarly titled measures used by other companies.

(b) Pro forma EBITDA adjusts 2011 historical EBITDA to give effect to the SandRidge Transactions. Pro forma EBITDA is calculated in the same manner as EBITDA, as described in note (a) to this table. Pro forma EBITDA is presented to reflect the SandRidge Transactions effect on our 2011 operating performance.

Reconciliation of Net Income (Loss) to EBITDA

	Pro Forma(1)	**Historical Years Ended December 31,**		
	2011	**2011**	**2010**	**2009**
		(in thousands)		
Net income (loss)	$ 41,472	$ 108,065	$ 190,565	$ (1,775,590)
Adjusted for:				
Income tax expense (benefit)	377	(5,817)	(446,680)	(8,716)
Interest expense(2)	240,686	243,818	239,343	186,137
Depreciation and amortization other	53,630	53,630	50,776	50,865
Depreciation and depletion oil and natural gas	320,674	326,614	275,335	176,027
EBITDA	$ 656,839	$ 726,310	$ 309,339	$ (1,371,277)

(1) This column consists of a reconciliation of net income to EBITDA, with all amounts calculated on a pro forma basis to give effect to the SandRidge Transactions.

(2) Excludes unrealized (gain) loss on interest rate swaps of ($6.2) million, $8.4 million and ($0.4) million for the years ended December 31, 2011, 2010 and 2009, respectively.

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Summary Historical Consolidated and Pro Forma Condensed Financial Information   Dynamic

The following table presents Dynamic s summary audited historical consolidated financial data for the periods shown, as well as summary unaudited pro forma condensed statement of operations data for the year ended December 31, 2011 showing the effects of Dynamic s acquisition of the XTO Properties. The summary consolidated financial data as of December 31, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009 has been derived from Dynamic s audited consolidated financial statements, which are attached hereto, for those dates and periods. The summary unaudited pro forma condensed statement of operations data for the year ended December 31, 2011 have been derived from Dynamic s unaudited pro forma condensed statements of operations for such period, which are also attached hereto. You should read the following summary financial data in conjunction with Dynamic s audited historical consolidated financial statements and related notes thereto and Dynamic s unaudited pro forma condensed statements of operations and related notes thereto.

The summary unaudited pro forma condensed statement of operations data have been presented for illustrative purposes only and do not purport to present what Dynamic s results of operations and financial condition would have been had these transactions actually occurred on the relevant dates, nor do they project our results of operations for any future period or our financial condition at any future date. We therefore caution you not to place undue reliance on the following summary unaudited pro forma condensed statement of operations data.

	Pro Forma	Historical Years Ended December 31,		
	2011	2011	2010	2009
		(in thousands)		
Statement of Operations Data:[1]				
Revenues	$ 616,420	$ 520,782	$ 358,627	$ 181,009
Expenses:				
Lease operating expense	133,094	113,487	89,399	60,618
Exploration expense	15,085	15,085	2,100	8,999
Depreciation, depletion and amortization	203,457	173,585	195,122	88,573
General and administrative expense	24,400	24,400	22,547	24,481
Other operating expense	84,124	77,505	73,047	51,142
Total expenses	460,160	404,062	382,215	233,813
Income (loss) from operations	156,260	116,720	(23,588)	(52,804)
Other income (expense):				
Interest expense, net	(13,007)	(9,503)	(13,541)	(7,138)
Commodity derivative income (expense)	43,734	43,734	6,990	(21,887)
Bargain purchase gain	282	282	4,024	161,351
Other	(145)	(145)	(1,080)	
Income (loss) before income taxes	187,124	151,088	(27,195)	79,522
Income tax benefit	5,359	5,359	14,814	20,387
Net income (loss)	$ 192,483	$ 156,447	$ (12,381)	$ 99,909
Less: net income (loss) attributable to noncontrolling interest	460	460	(4,070)	57,663
Net income (loss) attributable to Dynamic Offshore Resources, LLC	$ 192,023	$ 155,987	$ (8,311)	$ 42,246

(1) Dynamic historical and pro forma information was prepared using the successful efforts method of accounting.

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	As of December 31, 2011	2010
	(in thousands)	
Balance Sheet Data (as of the end of the period):		
Cash and cash equivalents	$ 58,696	$ 75,162
Property and equipment, net	$ 1,199,411	$ 864,645
Total assets	$ 1,463,769	$ 1,067,131
Total debt	$ 365,000	$ 203,205
Total equity	$ 519,087	$ 477,031
Total liabilities and equity	$ 1,463,769	$ 1,067,131

	Years Ended December 31, 2011	2010	2009
	(in thousands)		
Cash Flow Data:			
Net cash provided by operating activities	$ 277,142	$ 159,156	$ 38,912
Net cash provided by (used in) investing activities	$ (337,454)	$ (94,605)	$ 62,075
Net cash provided by (used in) financing activities	$ 43,846	$ (77,846)	$ (64,705)
Other Financial Data:			
EBITDAX[(a)]	$ 361,335	200,821	133,780
Pro forma EBITDAX[(b)]	$ 433,241	n/a	n/a

(a) EBITDAX is a non-GAAP financial measure used by Dynamic that most closely corresponds to our definition of EBITDA. Dynamic s EBITDAX is calculated as net income (loss) before income tax (benefit), interest expense, exploration expense, depreciation, depletion and amortization and accretion of asset retirement obligation.

(b) Pro forma EBITDAX gives effect to Dynamic s acquisition of the XTO Properties as though such acquisition occurred on December 31, 2010.

Reconciliation of Net Income (Loss) to EBITDAX

	Pro Forma[(1)] 2011	Historical Years Ended December 31, 2011	2010	2009
		(in thousands)		
Net income (loss)	$ 192,023	$ 155,987	$ (8,311)	$ 42,246
Adjusted for:				
Income tax benefit	(5,359)	(5,359)	(14,814)	(20,387)
Interest expense, net	13,007	9,503	13,541	7,138
Exploration expense	15,085	15,085	2,100	8,999
Depreciation, depletion and amortization	203,457	173,585	195,122	88,573
Accretion of asset retirement obligation	15,028	12,534	13,183	7,211
EBITDAX	$ 433,241	$ 361,335	$ 200,281	$ 133,780

(1) This column consists of a reconciliation of net income to EBITDAX, with all amounts calculated on a pro forma basis to give effect to Dynamic s 2011 purchase of the XTO Properties.

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Summary SandRidge and Dynamic Oil and Natural Gas Reserve and Production Data

The following table sets forth summary unaudited information with respect to our and Dynamic s estimated oil and natural gas reserves as of December 31, 2011. The SandRidge historical oil and natural gas reserve data presented below have been derived from our 2011 Annual Report on Form 10-K, as amended, and the Dynamic historical oil and natural gas reserve data are based on a reserve report prepared by Netherland, Sewell & Associates, Inc., which is dated as of December 31, 2011.

For convenience, we also present the mathematical combination of our and Dynamic s estimated oil and natural gas reserves. This combined number does not purport to represent what our estimated oil and natural gas reserves would have been if the Dynamic acquisition had occurred on or before December 31, 2011, in part because our reserve estimation processes and assumptions may differ from those used by Dynamic. Future exploration, exploitation and development expenditures, as well as future commodity prices and service costs, will affect the reserve volumes attributable to the Dynamic acquired properties. The reserves estimates shown below were determined using a 12-month average price for oil and natural gas for the year ended December 31, 2011.

	Estimated Proved Reserves as of December 31, 2011		
	SandRidge Historical	Dynamic Historical	Combined
Estimated Proved Reserves:			
Oil (MMBbls)	244.8	32.1	276.9
Natural gas (Bcf)	1,355.1	182.3	1,537.4
Total (MMBoe)	470.6	62.5	533.1
Estimated Proved Developed Reserves:			
Oil (MMBbls)	118.7	26.1	144.8
Natural Gas (Bcf)	670.4	146.9	817.3
Total (MMBoe)	230.4	50.6	281.0
Estimated Proved Undeveloped Reserves:			
Oil (MMBbls)	126.1	6.0	132.1
Natural Gas (Bcf)	684.7	35.4	720.1
Total (MMBoe)	240.2	11.9	252.1

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For illustrative purposes only, the following table sets forth summary unaudited pro forma information with respect to our and Dynamic s oil and natural gas production for the year ended December 31, 2011. This pro forma information differs from our and Dynamic s actual production and does not purport to represent what such production would have been if the transactions described in the notes to the table had occurred on or before December 31, 2010. For convenience, we also present the mathematical combination of our and Dynamic s pro forma oil and natural gas production. This combined number does not purport to represent what our oil and natural gas production would have been if the Dynamic acquisition had occurred on or before January 1, 2011.

	Production for the Year Ended December 31, 2011		
	SandRidge Pro Forma(1)	Dynamic Pro Forma(2)	Combined(3)
Oil (MBbls)	11,670(4)	4,340	16,010
Natural Gas (MMcf)	61,820	28,109(4)	89,929
Total (MBoe)	21,973	9,025	30,998
Average daily total volumes (MBoe/d)	60.2	24.7	84.9

(1) The pro forma SandRidge production data provided in this column gives effect to our November 2011 sale of certain natural gas assets in four counties in east Texas as if such disposition had occurred on December 31, 2010.

(2) The pro forma Dynamic production data provided in this column includes production from the XTO Properties as if Dynamic had acquired the XTO Properties on December 31, 2010.

(3) The combined production data provided in this column gives effect to the pro forma adjustments to our and Dynamic s 2011 production data that are referenced in footnotes 1 and 2 to this table.

(4) Includes natural gas liquids.

Caution Concerning Forward-Looking Statements

This Current Report on Form 8-K includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These statements express a belief, expectation or intention and are generally accompanied by words that convey projected future events or outcomes. The forward-looking statements include statements relating to when the Company expects to close the proposed transaction. These forward-looking statements are based on the Company s current expectations and assumptions and analyses made in light of the Company s experience and its perception of historical trends, current conditions and expected future developments, as well as other factors the Company believes are appropriate under the circumstances. However, whether actual results and developments will conform with the Company s expectations and predictions is subject to a number of risks and uncertainties, including the availability and terms of capital, and other factors, many of which are beyond the Company s control. Please see the discussion of risk factors in the our Annual Report on Form 10-K, as amended, for the year ended December 31, 2011 filed with the SEC. All of the forward-looking statements made in this Current Report on Form 8-K are qualified by these cautionary statements. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected in the forward-looking statements. The Company undertakes no obligation to update or revise any forward-looking statements.

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Report of Independent Registered Public Accounting Firm

To the Member of

Dynamic Offshore Resources, LLC

We have audited the accompanying consolidated balance sheets of Dynamic Offshore Resources, LLC (the Company) as of December 31, 2011 and 2010, and the related consolidated statements of operations, cash flows and owners equity for the years ended December 31, 2011, 2010 and 2009. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Dynamic Offshore Resources, LLC as of December 31, 2011 and 2010 and the results of their consolidated operations and their consolidated cash flows for the years ended December 31, 2011, 2010 and 2009, in conformity with accounting principles generally accepted in the United States of America.

Hein & Associates LLP

Houston, Texas

March 29, 2012

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DYNAMIC OFFSHORE RESOURCES, LLC

CONSOLIDATED BALANCE SHEETS

(In thousands)

	December 31, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 58,696	$ 75,162
Accounts receivable third parties	92,635	57,796
Accounts receivable affiliates	4	6
Insurance receivable		933
Derivative assets	44,471	11,990
Current portion of notes receivable abandonments	3,843	4,922
Other current assets	21,834	15,789
Total current assets	221,483	166,598
Property and equipment:		
Oil and gas properties, successful efforts method	1,728,289	1,220,407
Other property and equipment	4,073	3,223
Accumulated depreciation, depletion and amortization	(532,951)	(358,985)
Property and equipment, net	1,199,411	864,645
Long-term derivative assets	9,953	4,919
Notes receivable abandonments	17,108	15,274
Other assets	15,814	15,695
Total assets	$ 1,463,769	$ 1,067,131
Liabilities and Owners Equity		
Current liabilities:		
Accounts payable third parties	$ 65,488	$ 26,846
Accounts payable affiliates	601	50
Current portion of asset retirement obligations	51,133	71,225
Other current liabilities	83,952	56,780
Total current liabilities	201,174	154,901
Long-term debt	365,000	203,205
Asset retirement obligations	326,483	161,845
Deferred income taxes	43,481	49,561
Other long-term liabilities	8,544	20,588
Total liabilities	944,682	590,100
Commitments and contingencies (see Note 17)		
Owners equity:		
Member s capital	519,087	381,383
Noncontrolling interests in subsidiaries		95,648
Total owners equity	519,087	477,031

Total liabilities and owners equity	$ 1,463,769	$ 1,067,131

See notes to consolidated financial statements

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DYNAMIC OFFSHORE RESOURCES, LLC

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands)

	Year Ended December 31,		
	2011	**2010**	**2009**
Oil and gas revenues	$ 504,286	$ 345,812	$ 178,992
Other operating revenues	16,496	12,815	2,017
	520,782	358,627	181,009
Operating expenses:			
Lease operating expense	113,487	89,399	60,618
Exploration expense	15,085	2,100	8,999
Depreciation, depletion and amortization	173,585	195,122	88,573
General and administrative expense	24,400	22,547	24,481
Other operating expense	77,505	73,047	51,142
	404,062	382,215	233,813
Income (loss) from operations	116,720	(23,588)	(52,804)
Other income (expense):			
Interest expense, net	(9,503)	(13,541)	(7,138)
Commodity derivative income (expense)	43,734	6,990	(21,887)
Bargain purchase gain	282	4,024	161,351
Other	(145)	(1,080)	
Income (loss) before income taxes	151,088	(27,195)	79,522
Income tax benefit	5,359	14,814	20,387
Net income (loss)	156,447	(12,381)	99,909
Less: Net income (loss) attributable to noncontrolling interests	460	(4,070)	57,663
Net income (loss) attributable to Dynamic Offshore Resources, LLC	$ 155,987	$ (8,311)	$ 42,246

See notes to consolidated financial statements

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DYNAMIC OFFSHORE RESOURCES, LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Year Ended December 31, 2011	2010	2009
Cash flows from operating activities:			
Net income (loss)	$ 156,447	$ (12,381)	$ 99,909
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Amortization in interest expense, net	1,292	287	(219)
Accretion of asset retirement obligations	12,534	13,183	7,211
Depreciation, depletion and amortization	173,585	195,122	88,573
Commodity derivative (income) expense	(43,734)	(6,990)	21,887
Deferred income tax benefit	(5,359)	(14,814)	(18,199)
Bargain purchase gain	(282)	(4,024)	(161,351)
Other		71	
(Gain) loss on sale of assets	(19)	8,139	(140)
Changes in operating assets and liabilities, net of acquisitions:			
Accounts receivable and other assets	(25,308)	51,716	18,172
Accounts payable and other liabilities	7,986	(71,153)	(16,931)
Net cash provided by operating activities	277,142	159,156	38,912
Cash flows from investing activities:			
Additions to property and equipment	(98,681)	(57,726)	(42,154)
Acquisitions, net of cash acquired	(232,906)	(92,442)	26,072
Derivative settlements	(5,867)	43,171	76,088
Proceeds from asset sales		12,392	2,069
Net cash provided by (used in) investing activities	(337,454)	(94,605)	62,075
Cash flows from financing activities:			
Borrowings from revolving credit facility	390,000		
Repayments of revolving credit facility	(170,000)	(39,795)	(5,000)
Repayment of second lien term loan	(58,205)		(46,223)
Payments on insurance note payable			(1,111)
Contributions from member	524	28,000	21,808
Distributions to member	(40,075)	(53,076)	(34,664)
Distribution for net assets transferred under common control	(68,000)		
Net contributions from (distributions to) noncontrolling interest		(11,375)	2,844
Acquisition of noncontrolling interest in DBH, LLC	(6,840)	(1,600)	(2,160)
Debt issuance costs	(3,558)		(199)
Net cash provided by (used in) financing activities	43,846	(77,846)	(64,705)
Net increase (decrease) in cash and cash equivalents	(16,466)	(13,295)	36,282
Cash and cash equivalents, beginning of period	75,162	88,457	52,175
Cash and cash equivalents, end of period	$ 58,696	$ 75,162	$ 88,457

See notes to consolidated financial statements

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DYNAMIC OFFSHORE RESOURCES, LLC

CONSOLIDATED STATEMENTS OF OWNERS EQUITY

(In thousands)

	Dynamic Offshore Resources, LLC	Net Parent Investment	Total	Noncontrolling Interests	Total
Balance, December 31, 2008	$ 331,131	$ 44,226	$ 375,357	$ 59,073	$ 434,430
Contributions	21,835		21,835	15,886	37,721
Distributions	(34,664)		(34,664)	(9,933)	(44,597)
Acquisition of noncontrolling interest in DBH, LLC	6,544		6,544	(6,544)	
Net income (loss)	42,403	(157)	42,246	57,663	99,909
Balance, December 31, 2009	367,249	44,069	411,318	116,145	527,463
Contributions	28,000		28,000		28,000
Distributions	(50,639)	(2,437)	(53,076)	(11,375)	(64,451)
Acquisition of noncontrolling interest in DBH, LLC	3,452		3,452	(5,052)	(1,600)
Net income (loss)	(10,496)	2,185	(8,311)	(4,070)	(12,381)
Balance, December 31, 2010	337,566	43,817	381,383	95,648	477,031
Contributions	524		524		524
Distributions	(32,378)	(7,697)	(40,075)		(40,075)
Acquisition of noncontrolling interests in subsidiaries	89,268		89,268	(96,108)	(6,840)
Book value of net assets transferred under common control	42,518	(42,518)			
Distribution for net assets transferred under common control	(68,000)		(68,000)		(68,000)
Net income	149,589	6,398	155,987	460	156,447
Balance, December 31, 2011	$ 519,087	$	$ 519,087	$	$ 519,087

See notes to consolidated financial statements

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Dynamic Offshore Resources, LLC

Notes to Consolidated Financial Statements

Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Note 1 Organization and Basis of Presentation

Dynamic Offshore Resources, LLC (DOR) is a Delaware limited liability company wholly owned by Dynamic Offshore Holding, LP (DOH), a Delaware limited partnership. DOR was organized on September 17, 2007 for the purpose of acquiring and developing oil and gas properties. As a limited liability company, DOR is solely responsible for the debts, obligations and liabilities of the Company and no member or manager of the Company is obligated personally for any such debt, obligation or liability of the Company. Unless the context requires otherwise, references to we , us , our , or the Company are intended to mean the consolidated business and operations of DOR.

Basis of Presentation. The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP).

In September 2011, we acquired certain oil and natural gas properties in the Gulf of Mexico from a subsidiary of Moreno Group Holdings, LLC (MOR) for $68.0 million. Because the Company and MOR are under the common control of Riverstone Holdings, LLC (Riverstone), the acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of the acquired properties were recorded at MOR s carrying value and the Company s historical financial information was recast to include the acquired properties for all periods in which the Company and MOR were under the common control of Riverstone. Accordingly, the consolidated financial statements and notes thereto reflect the historical results of the Company combined with those of the acquired properties.

The effect of recasting the Company s consolidated financial statements to account for this common control transaction is shown below:

	December 31, 2010		
	Historical	**MOR**	**Recast**
Current assets	$ 163,209	$ 3,389	$ 166,598
Property and equipment	809,035	55,610	864,645
Other assets	35,870	18	35,888
Total assets	$ 1,008,114	$ 59,017	$ 1,067,131
Current liabilities	$ 153,828	$ 1,073	$ 154,901
Long-term liabilities	421,072	14,127	435,199
Owners equity	433,214	43,817	477,031
Total liabilities and owners equity	$ 1,008,114	$ 59,017	$ 1,067,131

	Year Ended December 31, 2010			Year Ended December 31, 2009		
	Historical	**MOR**	**Recast**	**Historical**	**MOR**	**Recast**
Operating revenues	$ 330,136	$ 28,491	$ 358,627	$ 157,153	$ 23,856	$ 181,009
Operating expenses	(355,909)	(26,306)	(382,215)	(209,800)	(24,013)	(233,813)
Net income (loss)	$ (14,566)	$ 2,185	$ (12,381)	$ 100,066	$ (157)	$ 99,909

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On October 13, 2009 (the acquisition date), DBH, LLC (DBH) acquired Bandon Oil and Gas, LP and Bandon Oil and Gas GP, LLC (Bandon LP and Bandon GP ; collectively, Bandon). DBH accounted for its acquisition of Bandon using the acquisition method, under which 100% of Bandon s assets and liabilities were recorded at fair value as of the acquisition date. During the measurement period, which ended October 12, 2010, DBH finalized the acquisition date valuation of certain assets and liabilities related to the acquisition. As a result, the bargain purchase gain increased $0.5 million. See Note 4 and Note 5. The consolidated balance sheet at December 31, 2009 and the consolidated statement of operations for the year ended December 31, 2009 have been retrospectively adjusted to reflect these adjustments as required by the business combinations accounting guidance.

Certain other reclassifications have been made to the prior year financial statements to conform to the current year presentation. These other reclassifications had no affect on total net assets, owners equity or net income.

In preparing the accompanying consolidated financial statements, the Company has reviewed, as determined necessary by the Company s management, events that have occurred after December 31, 2011, up until the issuance of the consolidated financial statements, which occurred on March 29, 2012. See Note 18.

Note 2 Significant Accounting Policies and Related Matters

Asset Retirement Obligations (AROs). AROs are legal obligations associated with the retirement of tangible long-lived assets that result from the asset s acquisition, construction, development and/or normal operations. The Company s AROs are based on the estimated costs of dismantlement, removal, site reclamation and similar activities associated with its oil and gas properties. An ARO is initially measured at its estimated fair value. Upon initial recognition, the Company records an increase to the carrying amount of the related long-lived asset and an offsetting ARO liability. The cost of the long-lived asset (including the ARO-related increase) is depreciated using a systematic and rational allocation method over the period during which the long-lived asset is expected to provide benefits. After the initial period of ARO recognition, the ARO will change as a result of either the passage of time or revisions to the original estimates of either the amounts of estimated cash flows or their timing. Changes due to the passage of time increase the carrying amount of the liability because there are fewer periods remaining from the initial measurement date until the settlement date; therefore, the present values of the discounted future settlement amount increases. These changes are recorded as a period cost called accretion expense. Upon settlement, AROs will be extinguished by the Company at either the recorded amount or the Company will recognize a gain or loss on the difference between the recorded amount and the actual settlement cost.

Cash and Cash Equivalents. Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. The Company considers cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value. As of December 31, 2011, accounts payable included $2.1 million of outstanding checks that were reclassified from cash and cash equivalents. There was no reclassification necessary as of December 31, 2010.

Concentration of Credit Risk. Financial instruments which potentially subject the Company to concentrations of credit risk consist primarily of trade accounts receivable and commodity derivative instruments.

The Company extends credit, primarily in the form of uoncollateralized oil and gas sales and joint interest owners receivables, to various companies in the oil and gas industry, which results in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions within the Company s industry and may accordingly impact its overall credit risk. The Company believes that the risk of these unsecured receivables is mitigated by the size, reputation and nature of the companies to which the Company extends credit.

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The following table lists the percentage of the Company s consolidated oil and gas revenues with purchasers that accounted for more than 10% of the Company s consolidated oil and gas revenues for the periods indicated:

	Year Ended December 31,		
	2011	**2010**	**2009**
Shell Trading (US) Company	51%	45%	23%
Conoco Phillips Corporation	22%	13%	28%
Texon LP	4%	14%	20%

Estimated losses on accounts receivable are provided through an allowance for doubtful accounts, based on the specific identification method. In evaluating the collectability of accounts receivable, the Company makes judgments regarding each party s ability to make required payments, economic events and other factors. As the financial condition of any party changes, circumstances develop or additional information becomes available, adjustments to an allowance for doubtful accounts may be required. The Company did not have an allowance for doubtful accounts as of December 31, 2011 and 2010.

The Company uses commodity derivative instruments to mitigate the effects of commodity price fluctuations. These derivative instruments expose the Company to counterparty credit risk. The Company s counterparties are generally major banks or financial institutions. All derivative instruments are executed under master agreements which allow the Company, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If the Company chooses to elect early termination, all asset and liability positions with the defaulting counterparty would be net settled at the time of election. The Company monitors the creditworthiness of its counterparties. However, the Company is not able to predict sudden changes in its counterparties creditworthiness. Should a financial counterparty not perform, the Company may not realize the benefit of some of its derivative instruments under lower commodity prices as well as incur a loss.

As of December 31, 2011, Citibank, Credit Suisse, Deutsche Bank, and an affiliate of The Royal Bank of Scotland (RBS) accounted for 38%, 34%, 14% and 14% of the Company s counterparty credit exposure related to commodity derivative instruments. These counterparties are major financial institutions possessing investment grade credit ratings, based upon minimum credit ratings assigned by Standard & Poor s Ratings Services, a division of the McGraw-Hill Companies, Inc.

Consolidation Policy. The Company s consolidated financial statements include the accounts of the Company and those subsidiaries in which the Company has a controlling interest, after the elimination of all material intercompany accounts and transactions. Third-party or affiliate ownership interests in the Company s controlled subsidiaries are presented as noncontrolling interests.

Contingencies. Certain conditions may exist as of the date the Company s consolidated financial statements are issued, which may result in a loss to the Company but which will only be resolved when one or more future events occur or fail to occur. The Company s management and its legal counsel assess such contingent liabilities, and such assessment inherently involves an exercise in judgment.

In assessing loss contingencies related to legal proceedings that are pending against the Company or unasserted claims that may result in proceedings, the Company s management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein. If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in the Company s consolidated financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss (if determinable and material), is disclosed.

Liabilities for environmental remediation costs arising from claims, assessments, litigation, fines, and penalties and other sources are charged to expense when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed.

Debt Issue Costs. Costs incurred in connection with the issuance of long-term debt are capitalized and charged to interest expense over the term of the related debt.

Income Taxes. The Company s provision for income taxes is solely applicable to federal tax obligations of Dynamic Offshore Resources NS Parent, Inc. (DOR NS), a wholly-owned subsidiary of the Company. Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities of DOR NS for financial reporting and tax purposes. A valuation allowance for deferred tax assets is recorded when it is more-likely-than-not that the benefit from the deferred tax assets will not be realized. The profits and losses of the Company s consolidated operations other than within DOR NS are reported directly to the taxing authorities by the sole member of the Company. Accordingly, no provision for income taxes has been included for those profits and losses in the accompanying consolidated financial statements, except as they relate to DOR NS.

The Company must recognize the tax effects of any uncertain tax positions it may adopt, if the position taken by it is more-likely-than-not sustainable. If a tax position meets such criteria, the tax effect to be recognized by the Company would be the largest amount of benefit with more than a 50% chance of being realized upon settlement. See Note 12 for additional information regarding income taxes.

Natural Gas Imbalances. Quantities of natural gas over-delivered or under-delivered are recorded monthly as receivables and payables using weighted average prices as of the time the imbalance was created. Imbalances not governed by operational balancing agreements are subject to annual adjustment to the lower of cost or market. Certain contracts require cash settlement of imbalances on a current basis. Under these contracts, imbalance cash-outs are recorded in the consolidated statements of operations as a sale or purchase of natural gas, as appropriate.

Derivative Instruments (Hedging). All derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the consolidated balance sheets at fair value. The Company does not designate its commodity derivative instruments as cash-flow hedges. Changes in the fair value of the Company s commodity derivative instruments are recorded in earnings as they occur and are included in other income (expense) in the Company s consolidated statements of operations.

Property and Equipment. The Company uses the successful efforts method to account for its oil and gas exploration and production activities. All costs for development wells, related plant and equipment, proved mineral interests in oil and gas properties, and related ARO costs are capitalized. Costs of exploratory wells are capitalized pending determination of whether the wells find proved reserves. Costs of wells that are assigned proved reserves remain capitalized. Costs also are capitalized for exploratory wells that have found oil and gas reserves even if the reserves cannot be classified as proved when the drilling is completed, provided the exploratory well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress toward assessing the reserves and the economic and operating viability of the project. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience, and average lease-term lives. Individually significant leases are reclassified to proved properties if successful and expensed on a lease-by-lease basis if unsuccessful or the lease term has expired. All other exploratory wells and costs are expensed. Oil and gas property costs associated with unproved oil and gas reserves, arising from business combinations, are assessed for transfer to proved properties based on the change in estimated field-by-field unproved reserve volumes from the acquisition closing date, beginning with the second fiscal year-end subsequent to the acquisition closing date.

Capitalized costs of producing oil and gas properties, along with support equipment and facilities, are amortized to expense by the unit-of-production method based on proved oil and gas reserves on a field-by-field basis. Upon sale or retirement, the cost and related accumulated depreciation, depletion and amortization are eliminated from the accounts and the resulting gain or loss is recognized.

Long-lived assets to be held and used, including proved and unproved oil and gas properties, are assessed for possible impairment by comparing their carrying values with their associated undiscounted, risk-weighted estimated future net cash flows. Events that can trigger assessments for possible impairments include write-downs of proved and unproved reserves based on field performance, significant decreases in the market value of an asset, significant changes in the extent or manner of use or a physical change in an asset, significant changes in the relationship between an asset s capitalized cost and the associated oil and gas reserves, and a more-likely-than-not expectation that a long-lived asset will be sold or otherwise disposed of significantly sooner than the end of its previously estimated useful life. Impaired assets are written down to their estimated fair values, generally their estimated discounted future net cash flows as adjusted by additional risk-weighting factors. For proved and unproved oil and gas properties, the Company performs the impairment review on an individual field basis. Impairment amounts are recorded as incremental depreciation, depletion and amortization expense. The Company recorded property impairment charges in 2011, 2010 and 2009 as described in Note 6. It is reasonably possible that other proved and unproved oil and gas properties could become impaired in the future if commodity prices decline.

In determining the fair values of proved and unproved properties acquired in business combinations, the Company prepares estimates of oil and gas reserves. The Company estimates future prices to apply to the estimated reserve quantities acquired, and estimates future operating and development costs, to arrive at estimates of future net cash flows. For the fair value assigned to proved, probable and possible reserves, the estimated future net cash flows are discounted using a market-based weighted average cost of capital rate deemed appropriate at the time of the business combination. To compensate for the inherent risk of estimating and valuing reserves, the discounted future net cash flows of proved, probable and possible reserves are reduced by additional risk-weighting factors.

Other property and equipment, consisting primarily of office furniture, equipment, leasehold improvements, computers and computer software, is stated at cost. Depreciation on other property and equipment is calculated on the straight-line method over the estimated useful lives of the assets, which range from three to seven years.

Revenue Recognition. The Company records revenues from the sales of crude oil, natural gas and natural gas liquids when product is delivered at a fixed or determinable price, title has transferred and collectability is reasonably assured.

When the Company has an interest with other producers in properties from which natural gas is produced, the Company uses the entitlement method to account for any imbalances. Imbalances occur when the Company sells more or less product than the Company is entitled to under its ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount that the Company sells in excess of its entitlement is treated as a liability and is not recognized as revenue. Any amount of entitlement in excess of the amount the Company sells is recognized as revenue and a receivable is accrued.

Segment Information. The Company acquires, exploits, develops, explores for and produces oil and gas. All of the Company s operations are located in the United States. The Company s management team administers all properties as a whole rather than as discrete operating segments. The Company tracks basic operational data by area. However, the Company measures financial performance as a single enterprise and not on an area-by-area basis. The Company allocates capital resources on a project-by-project basis across its entire asset base to maximize profitability without regard to individual areas or segments.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the period. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available.

Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) estimating oil and gas reserves, (2) estimating uncollected revenues, unbilled operating and general and administrative costs, capital expenditures and abandonment costs, (3) developing fair value assumptions, including estimates of future cash flows and discount rates, (4) analyzing long-lived assets for possible impairment, (5) estimating the useful lives of assets and (6) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results could differ materially from estimated amounts.

Recent Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board (FASB) issued authoritative guidance requiring entities to disclose both gross and net information about financial instruments and transactions eligible for offset in the statement of financial position as well as financial instruments and transactions subject to agreements similar to master netting arrangements. The additional disclosures will enable users of the financial statements to evaluate the effect or potential effect of netting arrangements on an entity s financial position. The guidance is effective for interim and annual periods beginning after January 1, 2013, and will primarily impact our disclosures associated with our commodity derivative instruments. We are currently evaluating the impact of this guidance.

In May 2011, FASB issued authoritative guidance amending certain accounting and disclosure requirements related to fair value measurements. The guidance clarifies (i) the requirement that the highest and best use concept is only relevant for measuring nonfinancial assets, (ii) requirements to measure the fair value of instruments classified in shareholders equity and (iii) the requirement to disclose quantitative information about the unobservable inputs used in a fair value measurement that is categorized within Level 3 of the fair value hierarchy. The guidance also (i) permits a reporting entity to measure the fair value of certain financial assets and liabilities managed in a portfolio at the price that would be received to sell a net asset position or transfer a net liability position for a particular risk, (ii) eliminates premiums or discounts related to size as a characteristic of the reporting entity s holding and (iii) expands disclosures for fair value measurement. The guidance is effective for interim and annual periods beginning after December 15, 2011. We are currently evaluating the impact of this guidance, but do not expect it to have a material impact on the Company s financial position or results of operations.

In December 2010, FASB issued authoritative guidance clarifying the acquisition date that should be used for reporting the pro forma financial information disclosures when comparative financial statements are presented. The guidance also improves the usefulness of the pro forma revenue and earnings disclosures by requiring a description of the nature and amount of material, nonrecurring pro forma adjustments that are directly attributable to the business combination. We adopted the provisions of this standard effective January 1, 2011, and it did not have a significant impact on our consolidated financial position, results of operations or cash flows.

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Note 3 Consolidated Financial Statements Information

The following table shows additional consolidated balance sheets information at the dates indicated:

	December 31, 2011	December 31, 2010
Accounts receivable from third parties		
Operating revenues	$ 70,231	$ 40,749
Joint interest receivables	13,565	13,908
Derivative assets	2,590	195
Other	6,249	2,944
	$ 92,635	$ 57,796
Other current assets		
Prepaid insurance	$ 5,067	$ 5,982
Prepaid royalties	10,782	5,871
Advances to operators	1,543	644
Deferred income taxes	2,571	3,292
Other	1,871	
	$ 21,834	$ 15,789
Other assets		
Natural gas imbalances receivable (1)	$ 10,768	$ 12,916
Debt issue costs, net	3,546	1,279
Restricted cash	1,500	1,500
	$ 15,814	$ 15,695
Other current liabilities		
Accrued expenses	$ 69,702	$ 37,372
Derivative liabilities	14,250	17,176
Other		2,232
	$ 83,952	$ 56,780
Other long-term liabilities		
Natural gas imbalances payable (1)	$ 5,919	$ 11,117
Long-term derivative liabilities	2,625	9,254
Other		217
	$ 8,544	$ 20,588

(1) As of December 31, 2011 and 2010, natural gas imbalances receivable were 3,068 MMcf and 3,946 MMcf. Natural gas imbalances payable were 1,282 MMcf and 3,516 MMcf as of the same dates.

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Other operating expense comprised the following for the periods indicated:

	Year Ended December 31,		
	2011	2010	2009
Other operating expense			
Insurance expense	$ 36,078	$ 36,677	$ 32,688
Workover expense	20,701	15,827	6,696
Accretion expense	12,534	13,183	7,211
Casualty loss (gain), net (See Note 15)	(164)	(3,380)	
Loss on abandonments	10,231	2,601	4,687
Loss (gain) on sale of assets	(19)	8,139	(140)
Other	(1,856)		
	$ 77,505	$ 73,047	$ 51,142

Note 4 Noncontrolling Interest in Subsidiaries

DBH, LLC

DBH is a Delaware limited liability company that was formed on September 24, 2009 to acquire and own Bandon. As of December 31, 2009, the Company owned a 66.1% controlling interest in DBH.

In December 2010 DOR repurchased a 2.4% member interest for $1.6 million. The Company s capital accounts were adjusted for the $3.5 million difference between the settlement price paid to the withdrawing member and the book value of the withdrawing member s share of total members capital at the time of the withdrawal. This amount is reflected in the consolidated statements of owners equity.

During 2011 DOR repurchased the remaining member interests in DBH from various members for $6.8 million. The Company s capital accounts were adjusted for the $5.1 million difference between the settlement price paid to the withdrawing members and the book value of the withdrawing members share of total members capital at the time of the withdrawal. Beginning June 1, 2011, the Company owned a 100% controlling interest in DBH.

SPN Resources, LLC (SPN)

On March 10, 2011, the Company acquired a Superior affiliate s membership interests in SPN and DBH. Consideration for the acquisition was a 10% ownership interest in the DOH and a modification of SPN s turnkey platform abandonment contract with Superior as described in Note 7. As a result of this transaction, the Company owns a 100% interest in SPN.

Note 5 Acquisitions

XTO Acquisition

On August 31, 2011, we acquired certain oil and natural gas interests in the Gulf of Mexico from XTO Offshore Inc. and other related subsidiaries of ExxonMobil Corporation (Exxon), for $173.7 million (the XTO Acquisition). This acquisition further strengthens our Gulf of Mexico shelf presence. The purchase price allocation was preliminary as of December 31, 2011. Acquisition-related expenses of $0.4 million are included in general and administrative expense in the accompanying consolidated statements of operations.

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Consideration paid	
Cash	$ 173,732
	$ 173,732
Assets acquired:	
Other current assets	$ 10,737
Property and equipment	246,508
Total assets acquired	257,245
Liabilities assumed:	
Other current liabilities	7,903
AROs, noncurrent portion	75,610
Total liabilities assumed	83,513
Net assets acquired	$ 173,732

Actual and Pro Forma Impact of 2011 Acquisition (Unaudited). Revenues and direct operating expenses attributable to the XTO acquisition included in the Company s consolidated statement of operations for the year ended December 31, 2011 were $47.1 million and $6.9 million.

The following table presents pro forma information for the Company as if the XTO acquisition occurred on January 1, 2010:

	Year Ended December 31,	
	2011	2010
Revenues	$ 616,420	$ 512,994
Income from operations	156,260	28,833
Net income	192,483	34,756
Less: Net income attributable to noncontrolling interests	460	(4,070)
Net income attributable to Dynamic Offshore Resources, LLC	192,023	38,826

The historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the acquisitions and factually supportable. The unaudited pro forma consolidated results are not necessarily indicative of what the Company s consolidated results of operations actually would have been had the acquisitions been completed on January 1, 2010. In addition, the unaudited pro forma consolidated results do not purport to project the future results of operations of the combined company. The unaudited pro forma results reflect the direct operating expenses of the properties acquired, interest expense on acquisition-related indebtedness and an adjustment to recognize incremental depreciation, depletion and amortization expense, using the unit-of-production method, resulting from the purchase of the properties.

MOR Acquisition

On September 14, 2011, we acquired certain oil and natural gas properties in the Gulf of Mexico from a subsidiary of Moreno Group Holdings, LLC (MOR) for $68.0 million. Because the Company and MOR are under the common control of Riverstone Holdings, LLC (Riverstone), the acquisitions were accounted for as transactions between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of the acquired properties were recorded at MOR s carrying value and the Company s historical financial information was recast to include the acquired properties for all periods in which the Company and

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MOR were under the common control of Riverstone. Accordingly, the consolidated financial statements and notes thereto, including the historical financial statements and notes thereto, reflect the results of the Company combined with those of the acquired properties.

2010 Acquisitions

Bullwinkle Acquisition. On February 1, 2010, DOR and a wholly-owned subsidiary of Superior acquired the deepwater Gulf of Mexico Bullwinkle field and related infrastructure. DOR is now the operator and 49% owner of the field with Superior retaining the remaining interest. DOR is required to fund its share of the assumed asset retirement obligations, which has been capped at $49 million, by no later than January 31, 2013. The $49 million is payable in the following increments: (i) $1.8 million upon the permanent abandonment of each existing wellbore, (ii) sixteen monthly payments of $1.5 million, beginning on the last business day of February 2010, (iii) $1.0 million on the last business day of June 2011, and (iv) any remainder on January 31, 2013. In addition to the revenue generated from oil and gas production, the platform also generates revenue from several production handling arrangements for other third-party fields. Acquisition-related expenses of $0.1 million are included in general and administrative expense in the accompanying consolidated statements of operations.

Samson Acquisition. On July 8, 2010, DOR purchased substantially all of the oil and gas properties of Samson Offshore Company and Samson Contour Energy E&P, LLC (collectively, Samson) located in the Gulf of Mexico for $97.7 million. Acquisition-related expenses of $0.1 million are included in general and administrative expense in the accompanying consolidated statements of operations. The acquisition broadens the Company s leasehold footprint in the Gulf of Mexico.

	Year Ended December 31, 2010			
	Bullwinkle	Samson	Other (1)	Total
Consideration paid				
Cash	$	$ 97,693	$ 3,664	$ 101,357
	$	$ 97,693	$ 3,664	$ 101,357
Assets acquired:				
Cash	$ 3,498	$	$ 5,417	$ 8,915
Hurricane insurance claims		1,775		1,775
Property and equipment	43,761	109,567	4,107	157,435
Other noncurrent assets	148		17	165
Total assets acquired	47,407	111,342	9,541	168,290
Liabilities assumed:				
AROs, current portion	34,079		1,410	35,489
Other current liabilities		70		70
AROs, noncurrent portion	13,328	13,579	443	27,350
Total liabilities assumed	47,407	13,649	1,853	62,909
Net assets acquired	$	$ 97,693	$ 7,688	$ 105,381
Bargain purchase gain	$	$	$ 4,024	$ 4,024

(1) Includes an acquisition pursuant to a preferential purchase right, wherein the seller had attributed a negative fair value to a property. As a result, the Company received $5.4 million in cash and the property, and recognized a bargain purchase gain of $4.0 million.

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2009 Acquisitions

Bayou Bend Acquisition. On May 29, 2009, DOR purchased substantially all of the U.S. oil and gas properties of Bayou Bend Petroleum Ltd. and its subsidiaries (Bayou Bend) for $12.5 million. An additional payment of $1.1 million was made on April 1, 2011, based upon the increase in proved oil and gas reserves attributable to the purchased interests as of December 31, 2010 above a specified threshold. The purchase price allocation did not reflect a liability for this contingent obligation. As a result, the amount was recorded to other expense during 2010.

The acquisition broadens the Company s leasehold footprint in the Gulf of Mexico and provides a new growth area for the Company in the shallow Louisiana state waters centered on the Marsh Island exploration project. Acquisition-related expenses of $0.3 million are included in general and administrative expense in the accompanying consolidated statements of operations.

Bandon Acquisition. On October 13, 2009, in a nonmonetary exchange with the prior owners of Bandon, DBH acquired a 100% ownership interest in Bandon.

The acquisition substantially increased the Company s presence in the Gulf of Mexico. Acquisition-related expenses of $0.8 million are included in general and administrative expense in the accompanying consolidated statements of operations.

The acquisition was accounted for using the acquisition method and Bandon s results of operations were included in the Company s consolidated statement of operations effective October 13, 2009.

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	Year Ended December 31, 2009		
	Bandon (1)	Bayou Bend	Total
Consideration paid			
Cash	$	$ 12,500	$ 12,500
	$ 5,294	$ 12,500	$ 17,794
Assets acquired:			
Cash	$ 41,740	$	$ 41,740
Other current assets	41,329		41,329
Property and equipment	327,872	13,645	341,517
Other noncurrent assets	8,308		8,308
Total assets acquired	449,124	13,645	462,769
Liabilities assumed:			
AROs, current portion	44,986	214	45,200
Other current liabilities	23,269		23,269
AROs, noncurrent portion	55,726	931	56,657
Other noncurrent liabilities	7,274		7,274
Total liabilities assumed	282,479	1,145	283,624
Net assets acquired	$ 166,645	$ 12,500	$ 179,145
Bargain purchase gain	$ 161,351	$	$ 161,351

(1) The Company s estimate of the net assets fair value exceeded the fair value of the total consideration paid, which management believes resulted from Bandon s financial difficulties prior to the acquisition.

Note 6 Property and Equipment

The components of property and equipment were as follows at the dates indicated:

	December 31,	
	2011	2010
Proved oil and gas properties	$ 1,592,698	$ 1,080,031
Unproved oil and gas properties	135,591	140,376
Other property and equipment	4,073	3,223
	1,732,362	1,223,630
Accumulated depreciation, depletion and amortization	(532,951)	(358,985)
	$ 1,199,411	$ 864,645

Substantially all of the Company s assets serve as collateral under the debt agreements, as discussed in Note 9.

Asset Impairments. For the years ended December 31, 2011, 2010 and 2009, the Company determined that the carrying amount of certain of its oil and gas properties was not recoverable from estimated future net cash flows and, therefore, was impaired. The assets were written down to their estimated fair values, which were determined using discounted cash flow models. The discounted cash flow models used exchange-based forward commodity prices and a discount rate of 10%. Estimated future net cash flows from probable and possible reserves were risk-adjusted.

The pre-tax impairment charges of $10.9 million ($10.2 million after-tax), $60.5 million ($52.5 million

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after-tax), and $10.8 million ($7.0 million after-tax) for 2011, 2010, and 2009 are included in the Company s consolidated statements of operations as incremental depreciation, depletion and amortization expense. See Note 11. For the year ended December 31, 2011, the entire pre-tax amount resulted from declines in natural gas prices, well performance issues, and changes in the estimated abandonment costs of properties. For the year ended December 31, 2010, the entire pre-tax amount resulted from declines in natural gas prices and well performance issues. For the year ended December 31, 2009, the entire pre-tax amount resulted from changes in the estimated abandonment costs of properties acquired in the 2008 acquisition of DOR NS.

Note 7 Asset Retirement Obligations

The following table summarizes the activity for the Company s asset retirement obligations for the periods indicated:

	Year Ended December 31,		
	2011	2010	2009
Beginning of period	$ 233,070	$ 218,902	$ 111,804
Liabilities acquired	96,070	62,837	101,858
Liabilities sold	(47)	(1,287)	(401)
Liabilities settled	(46,510)	(63,350)	(18,604)
Accretion expense	12,534	13,183	7,211
Revisions to previous estimates	82,499	2,785	17,034
End of period	$ 377,616	$ 233,070	$ 218,902
Current portion	$ 51,133	$ 71,225	$ 49,622
Long-term portion	326,483	161,845	169,280
	$ 377,616	$ 233,070	$ 218,902

SPN Resources, LLC (SPN), our wholly-owned subsidiary, has a platform abandonment contract with Superior Energy Services, Inc. (Superior) whereby Superior will provide well abandonment and pipeline and platform decommissioning services with respect to the specified properties for the greater of its actual cost or the fixed turnkey amount. This contract covers only routine end-of-life well abandonment and pipeline and platform decommissioning for properties owned and operated by SPN at March 14, 2008 and has a remaining fixed price of approximately $133.3 million as of December 31, 2011. For any additional wells drilled and completed after March 15, 2008, the abandonment liability was estimated based on similar wells in the field.

Note 8 Notes Receivable

Notes receivable consist of contractual obligations of sellers of oil and gas properties to reimburse the Company a specified amount following the abandonment of acquired properties. The Company invoices the seller specified amounts following the performance of decommissioning operations (abandonment and structure removal) in accordance with the applicable agreements with the seller. These receivables are recorded at present value, and the related discounts are amortized to interest income, based on the expected timing of the decommissioning. For the years ended December 31, 2011, 2010 and 2009 the amortization was $1.0 million, $1.1 million, and $1.2 million.

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Note 9 Long-Term Debt

The Company had the following debt outstanding at the dates indicated:

	December 31, 2011	December 31, 2010
Obligation of DOR		
Revolving Credit Agreement, variable rate, due June 2015	$ 365,000	$ 145,000
Obligations of Bandon (1)		
Second Lien Term Loan, variable rate, due October 2014		58,205
	$ 365,000	$ 203,205
Letters of credit issued	$	$

(1) The Company consolidates the debt of Bandon; however, the debt of Bandon is secured by substantially all of the assets of Bandon. The Company does not provide guarantees of the indebtedness of Bandon and none of the Company s directly owned assets are pledged as collateral for Bandon s indebtedness.

Description of Debt Obligations

Obligation of DOR

$750 Million Amended and Restated Credit Agreement. On June 20, 2011, DOR amended and restated its existing credit agreement to provide for a four year $750 million revolving credit facility (the DOR Credit Facility) with a group of financial institutions (the Lenders). As of December 31, 2011 the borrowing base under the DOR Credit Facility was $430 million. In addition, $100 million of the borrowing base is available for the issuance of letters of credit.

The DOR Credit Facility is subject to semi-annual borrowing base redeterminations on April 1 and October 1 of each year. Due to the pending sale discussed in Note 18, the Company requested, and has received, a waiver for the borrowing base determination scheduled for April 1, 2012. In addition to the scheduled semi-annual borrowing base redeterminations, the Lenders or the Company have the right to re-determine the borrowing base at any time, provided that no party can request more than one such redetermination between the regularly scheduled borrowing base redeterminations. The determination of the Company s borrowing base is subject to a number of factors, including the quantities of proved oil and gas reserves, the Lenders price assumptions and other various factors, some of which may be out of the Company s control. The Lenders can re-determine the borrowing base to a lower level than the current borrowing base if they determine that the Company s oil and gas reserves, at the time of redetermination, are inadequate to support the borrowing base then in effect. In this case, the Company would be required to make six monthly payments each equal to one sixth of the amount by which the aggregate outstanding loans and letters of credit exceed the borrowing base.

Obligations under the DOR Credit Facility are secured by liens on substantially all of the Company s assets. The DOR Credit Facility also contains other restrictive covenants, including, among other items, maintenance of leverage ratio, interest coverage ratio and current ratio (all as defined in the credit agreement), restrictions on cash dividends and restrictions on incurring additional indebtedness. The DOR Credit Facility also requires DOR to enter into commodity price hedging agreements for at least half of its estimated oil and gas production from proved developed producing reserves.

At our election, outstanding balances bear interest at either the alternate base rate plus a margin (based on a sliding scale of 1.25% to 2.00% based upon borrowing base usage) or the London Interbank Offered Rate (LIBOR) plus a margin (based on a sliding scale of 2.25% to 3.00% based upon borrowing base usage). The alternate base rate is equal to the higher of The Royal Bank of Scotland s prime rate or the federal funds rate plus 0.5% per annum or the reference LIBOR plus 1%, and the LIBOR is equal to the applicable British Bankers Association LIBOR for deposits in U.S. dollars. The DOR Credit Facility also provides for commitment fees (based on a margin of 0.5%) calculated on the difference between the borrowing base and the aggregate outstanding loans and letters of credit under the DOR Credit Facility.

The Company s management believes the Company was in compliance with its debt covenants as of December 31, 2011.

Obligations of Bandon

Second Lien Amended and Restated Credit Agreement. On October 13, 2009, Bandon entered into a Second Lien Amended and Restated Credit Agreement (the Second Lien Agreement). During 2011 the outstanding balance of the Second Lien Agreement was repaid and retired.

The following table shows the range of interest rates paid and weighted average interest rate paid on our variable-rate debt obligations for the year ended December 31, 2011:

	Range of Interest Rates Paid	Weighted Average Interest Rate Paid
Revolving Credit Agreement	2.8% to 5.0%	2.9%
Second Lien Term Loan	8.0% to 8.0%	8.0%

Note 10 Risk Management Activities

The Company s principal market risks are its exposure to changes in commodity prices, particularly to the prices of oil and gas, nonperformance by the Company s counterparties, and changes in interest rates.

The Company s revenues are derived principally from the sale of oil and gas. The prices of oil and gas are subject to market fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond the Company s control. The Company monitors these risks and enters into commodity derivative transactions designed to mitigate the impact of commodity price fluctuations on the Company s business.

The primary purpose of the Company s commodity risk management activities is to hedge the Company s exposure to commodity price risk and reduce fluctuations in the Company s operating cash flow despite fluctuations in commodity prices. As of December 31, 2011, the Company has hedged the commodity price associated with a portion of its expected oil and gas sales volumes for the years 2012 through 2013 by entering into derivative financial instruments comprising swaps and collars. The percentages of the Company s expected oil and gas that are hedged decrease over time.

With swaps, the Company receives an agreed upon fixed price for a specified notional quantity of oil or gas and the Company pays the hedge counterparty a floating price for that same quantity based upon published index prices. Since the Company receives from its oil and gas marketing counterparties a price based on the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged.

For basis swaps, the Company receives a fixed differential between two regional oil index prices and pays a floating differential on the same two index prices to the contract counterparty. Since the Company receives from

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its oil and gas marketing counterparties a price based on the same floating differential from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed differential in advance for the volumes hedged.

In order to avoid having a greater volume hedged than the Company s actual oil and gas sales volumes, the Company typically limits its use of swaps and basis swaps to hedge the prices of less than the Company s expected sales volumes.

In a typical collar transaction, if the floating price based on a market index is below the floor price in the derivative contract, the Company receives from the counterparty an amount equal to this difference multiplied by the specified volume. If the floating price exceeds the floor price and is less than the ceiling price, no payment is required by either party. If the floating price exceeds the ceiling price, the Company must pay the counterparty an amount equal to the difference multiplied by the specified volume. If the Company has less production than the volumes specified under the collar transaction when the floating price exceeds the ceiling price, the Company must make payments against which there is no offsetting revenues from production.

The Company s commodity hedges may expose the Company to the risk of financial loss in certain circumstances. The Company s hedging arrangements provide the Company protection on the hedged volumes if market prices decline below the prices at which these hedges are set. If market prices rise above the prices at which the Company has hedged, the Company will receive less revenue on the hedged volumes than in the absence of hedges.

Interest Rate Risk. The Company is exposed to changes in interest rates, primarily as a result of variable rate borrowings under its debt agreements. To the extent that interest rates increase, interest expense for the Company s variable rate debt will also increase.

Credit Risk. The Company s credit exposure related to commodity derivative instruments is represented by the fair value of contracts with a net positive fair value to the Company at the reporting date. At such times, these outstanding instruments expose the Company to credit loss in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of one or more of the Company s counterparties decline, the Company s ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, the Company may sustain a loss and the Company s cash receipts could be negatively impacted.

As of December 31, 2011, Citibank, Credit Suisse, Deutsche Bank, and an affiliate of The Royal Bank of Scotland (RBS) accounted for 38%, 34%, 14% and 14% of the Company s counterparty credit exposure related to commodity derivative instruments. These counterparties are major financial institutions possessing investment grade credit ratings, based upon minimum credit ratings assigned by Standard & Poor s Ratings Services, a division of the McGraw-Hill Companies, Inc.

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The Company had commodity derivatives with the following terms outstanding as of December 31, 2011, none of which have been designated as cash-flow hedges:

	Year Ending December 31, 2012	2013
Crude Oil		
Swaps (Bbl)	1,662,000	1,250,000
Average price ($ per Bbl)	91.86	100.47
Collars (Bbl)	418,000	168,000
Average price ($ per Bbl)		
Floor price (put)	82.99	80.00
Ceiling price (call)	108.51	102.50
LLS-WTI Differential Spread (Bbl)	2,300,000	
Average price ($ per Bbl)	17.17	
Natural Gas		
Swaps (MMBtu)	3,630,000	
Average price ($ per MMBtu)	6.16	
Collars (MMBtu)	8,115,000	6,000,000
Average price ($ per MMBtu)		
Floor price (put)	4.08	3.75
Ceiling price (call)	6.62	6.65

The following reflects the fair values of derivative instruments in the Company s consolidated balance sheets as of the dates indicated:

	Asset Derivatives		
Derivatives not designated as hedging instruments under ASC 815	**Balance Sheet Location**	**Fair Value as of December 31, 2011**	**2010**
Commodity derivatives	Current assets	$ 44,471	$ 11,990
Commodity derivatives	Long-term assets	9,953	4,919

	Liability Derivatives		
Derivatives not designated as hedging instruments under ASC 815	**Balance Sheet Location**	**Fair Value as of December 31, 2011**	**2010**
Commodity derivatives	Current liabilities	$ 14,250	$ 17,176
Commodity derivatives	Long-term liabilities	2,625	9,254

See Note 11 for additional disclosures related to derivative instruments.

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Note 11 Fair Value Measurements

Accounting standards pertaining to fair value measurements establish a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include:

Level 1, defined as observable inputs such as quoted prices in active markets;

Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and

Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

The Company s derivative contracts are reported in its consolidated financial statements at fair value. These contracts consist of over-the-counter swaps and collars, which are not traded on a public exchange.

The fair values of swap contracts are determined based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. Therefore, the Company has categorized these swap contracts as Level 2.

For collars, the Company estimates the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract terms. Therefore, the Company has categorized its collars as Level 2.

The Company has consistently applied these valuation techniques and believes it has obtained the most accurate information available for the types of derivative contracts it holds.

The following table sets forth, by level within the fair value hierarchy, the Company s financial assets and liabilities measured at fair value on a recurring basis as of the dates indicated:

As of December 31, 2011	0000000 Total	0000000 Level 1	0000000 Level 2	0000000 Level 3
Commodity derivative assets	$ 54,424	$	$ 54,424	$
Commodity derivative liabilities	$ 16,875	$	$ 16,875	$

As of December 31, 2010	0000000 Total	0000000 Level 1	0000000 Level 2	0000000 Level 3
Commodity derivative assets	$ 16,909	$	$ 16,909	$
Commodity derivative liabilities	$ 26,430	$	$ 26,430	$

These 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 the fair value assets and liabilities and their placement within the fair value hierarchy levels.

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis and are subject to fair value adjustments under certain circumstances (e.g., when there is evidence of impairment).

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Asset Impairments. Information about impaired assets as of the dates of the assessment is as follows:

	0000000	0000000	0000000
	Year Ended December 31,		
	2011	**2010**	**2009**
Net Book Value (1)	$ 17,248	$ 91,052	$ 12,044
Impairment Charge	10,851	60,513	10,808
Level 3	$ 6,397	$ 30,539	$ 1,236

(1) Amount represents net book value at the date of impairment.

See Note 6 for a discussion of the methods and assumptions used to estimate the fair values of the impaired assets.

Note 12 Income Taxes

The components of the Company s provisions for federal income taxes were as follows for the periods indicated:

	0000000	0000000	0000000
	Year Ended December 31,		
	2011	**2010**	**2009**
Current benefit	$	$	$ (2,188)
Deferred (benefit) expense	(5,359)	(14,814)	(18,199)
	$ (5,359)	$ (14,814)	$ (20,387)

Set forth below is a reconciliation between DOR NS income tax benefit (expense) computed at the United States statutory rate on income (loss) before income taxes and the income tax benefit (expense) in the accompanying consolidated statements of operations:

	0000000	0000000	0000000
	Year Ended December 31,		
	2011	**2010**	**2009**
U.S. federal income tax provision at statutory rate	$ 5,729	$ 15,507	$ 20,198
Non-deductible expenses	(15)	(8)	(22)
Audit settlement		(647)	
Return to provision		(507)	
Other	(355)	469	211
	$ 5,359	$ 14,814	$ 20,387

No material uncertain tax positions were identified during 2011. The Company believes that DOR NS income tax filing positions and deductions will more-likely-than-not be sustained on audit and does not anticipate any adjustments that will result in a material adverse effect on the Company s financial condition, results of operations or cash flows. Therefore, no reserves for uncertain income tax positions have been recorded.

As of December 31, 2011, DOR NS had regular federal net operating loss carryforwards of $1.0 million, which begin to expire in 2027.

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The components of DOR NS deferred income tax assets and liabilities as of the dates indicated were as follows:

	December 31, 2011	December 31, 2010
Deferred tax assets:		
Asset retirement obligation	$ 13,806	$ 11,913
Loss carryforwards	356	144
Alternative minimum tax	2,571	2,571
Allowance for bad debts	479	577
Other		
	17,212	15,205
Deferred tax liabilities:		
Property and equipment	(57,943)	(61,474)
Other	(179)	
	(58,122)	(61,474)
Net deferred tax liabilities	$ (40,910)	$ (46,269)
Balance sheet classification of deferred tax assets and liabilities:		
Current asset	$ 2,571	$ 3,292
Long-term liability	(43,481)	(49,561)
	$ (40,910)	$ (46,269)

Note 13 Related Party Transactions

Relationship with Superior. Superior owns a 10% ownership interest in DOH, and is party to the turnkey platform abandonment contract described in Note 7. Superior provides various field-level services to the Company. These transactions were recorded in the consolidated financial statements as follows:

	00000000	00000000	00000000
		December 31,	
	2011	2010	2009
Insurance receivable	$ 7	$ 4,436	$ 1,454
Additions to property and equipment	14,602	4,429	3,815
Asset retirement obligations settled	12,864	13,410	5,845
Lease operating expense	1,895	2,311	1,665
Workover expense	4,882	1,301	360
	$ 34,250	$ 25,887	$ 13,139

Relationship with DOH GP. The Company has no employees. Dynamic Offshore Holding GP, LLC (DOH GP), the general partner of DOH, charges all of its employee costs to the Company, at cost, as part of the administrative services agreement between DOH GP and the Company. The Company allocates employee costs charged by DOH GP and other general and administrative costs, at cost, among its consolidated subsidiaries based on an agreed sharing percentage. For the years ended December 31, 2011, 2010, and 2009, DOH GP charged DOR $20.0 million, $15.4 million, and $17.3 million under the agreement, which is included in the accompanying consolidated statements of operations as general and administrative expense and lease operating expense.

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Affiliate receivables and payables were as follows as of the dates indicated:

	December 31, 2011	December 31, 2010
Receivable from DOH GP	$ 4	$ 6
Payable to SESI and its affiliates	$ 601	$ 50

Note 14 Owners Equity

The limited company agreement (the Agreement) of DOR, dated September 17, 2007 does not provide for any shares of stock representing the membership interests. Membership interests are determined in accordance with the contributions, distributions and profit and loss allocations made by, to, or on behalf of, each individual member in accordance with the Agreement.

As of December 31, 2011, DOH was the sole member of DOR.

See also Note 18.

Note 15 Hurricane Remediation and Insurance Claims

During 2008, Hurricanes Ike and Gustav caused property damage and disruptions to the Company s exploitation and production activities. The Company currently has insurance coverage for named windstorms but does not carry business interruption insurance. The Company recognizes insurance receivables with respect to capital, repair and plugging and abandonment costs as a result of hurricane damage when the Company deems collection of those receivables to be reasonably assured.

Except for the removal of a toppled platform that was supporting the Company s Ship Shoal Block 253 operations, activities related to the 2008 hurricanes are complete and the Company expects no further recognition of casualty gain or loss in its consolidated statements of operations with respect to those storms.

Note 16 Supplemental Cash Flow Information

The following table provides supplemental cash flow information for the periods indicated:

	Year Ended December 31, 2011	2010	2009
Cash:			
Interest paid	$ 8,409	$ 11,589	$ 7,871
Non-cash:			
Contribution from noncontrolling interest	5,032		5,294
Acquisition of Bandon			5,294
Increase arising from purchase accounting:			
Purchase of oil and gas properties		44,189	
Purchase of noncontrolling interest in DBH (see Note 4)	89,268	3,452	4,384

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Note 17 Commitments and Contingencies

Operating Leases. The Company holds leases for office space in Houston, Texas. Noncancellable commitments under the leases are $2.0 million for the year ending December 31, 2012. During 2011, 2010 and 2009, the Company paid $2.0 million, $2.3 million, and $0.5 million in rent under its operating leases.

Legal Proceedings. From time to time, the Company may be involved in litigation arising out of the normal course of its business. In management s opinion, the Company is not involved in any litigation, the outcome of which would have a material effect on its consolidated financial position, results of operations, or liquidity.

Note 18 Subsequent Event

On February 1, 2012, SandRidge Energy, Inc. entered into an agreement to acquire DOR for aggregate consideration of $1.3 billion, consisting of approximately $680 million in cash and approximately 74 million shares of SandRidge common stock valued at $8.02 per share. The acquisition is expected to close in April 2012.

Note 19 Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The supplemental data presented herein reflects information for the Company s crude oil and natural gas producing activities, all of which are in the United States of America.

Results of Operations for Oil and Gas Producing Activities

Our results of operations from oil and gas producing activities below exclude non-oil and gas revenues, general and administrative expenses, interest charges and interest income. Income tax expense was determined by applying the statutory rates to pretax operating results of our taxable subsidiary:

	00000000	00000000	00000000
	Year Ended December 31,		
	2011	**2010**	**2009**
Revenues from oil and gas producing activities	$ 504,286	$ 345,812	$ 178,992
Production costs	(113,487)	(89,399)	(60,618)
Workover costs	(20,701)	(15,827)	(6,696)
Accretion expense	(12,534)	(13,183)	(7,211)
Loss on abandonments	(10,231)	(2,601)	(4,687)
Exploration expenses	(15,085)	(2,100)	(8,999)
Depreciation, depletion and amortization expense (1)	(172,801)	(194,358)	(87,917)
Income tax (expense) benefit	930	10,548	3,505
Results of operations from producing activities	$ 160,377	$ 38,892	$ 6,369

(excluding general and administrative and interest costs)

(1) This amount only reflects DD&A of capitalized costs of proved oil and gas properties and,therefore, does not agree with DD&A reflected in the statement of operations.

Oil and Gas Reserves

The Company s estimates of proved reserves as of December 31, 2011, 2010 and 2009 are based on estimates prepared by our internal engineers, in accordance with the rules and regulations regarding oil and natural gas reserve reporting. Users of this information should be aware that the process of estimating quantities of proved and proved-developed crude oil and natural gas reserves is very complex, requiring significant subjective

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decision making in the analysis and evaluation of all geological, engineering, and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors, including additional development activity, additional production data, evolving production history, and continual reassessment of the viability of production under different economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate. Proved developed oil and gas reserves are proved reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well, and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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The following table sets forth the Company s net proved reserves, including changes therein:

	Crude oil (MBbl)	Natural gas (MMcf)
2009		
Proved Reserves		
Beginning balance	13,136	61,636
Revision of previous estimates	1,570	(935)
Extensions, discoveries and other additions		
Purchase of reserves in-place	3,783	69,795
Sale of reserves in-place		
Production	(2,145)	(10,555)
Ending balance	16,344	119,941
Proved Developed Reserves, December 31, 2009	14,031	101,771
Proved Undeveloped Reserves, December 31, 2009	2,313	18,170
2010		
Proved Reserves		
Beginning balance	16,344	119,941
Revision of previous estimates	3,266	5,554
Extensions, discoveries and other additions	196	2,696
Purchase of reserves in-place	7,959	19,455
Sale of reserves in-place	(132)	(5,475)
Production	(3,289)	(18,468)
Ending balance	24,344	123,703
Proved Developed Reserves, December 31, 2010	20,191	110,253
Proved Undeveloped Reserves, December 31, 2010	4,153	13,450
2011		
Proved Reserves		
Beginning balance	24,344	123,703
Revision of previous estimates	4,317	8,022
Extensions, discoveries and other additions		
Purchase of reserves in-place	7,139	72,701
Sale of reserves in-place		
Production	(3,728)	(22,070)
Ending balance	32,072	182,356
Proved Developed Reserves, December 31, 2011	26,055	146,947
Proved Undeveloped Reserves, December 31, 2011	6,017	35,409

As of December 31, 2011, 2010 and 2009, proved reserves attributable to noncontrolling interests in consolidated subsidiaries were 0%, 17%, and 23% of the total.

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Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities

Costs incurred, on an accrual basis, represent amounts capitalized or expensed during the three years ended December 31, 2011 for property acquisition, exploration, development and abandonment activities. Costs incurred for property acquisitions, exploration, development and abandonment activities were as follows:

	0000000	0000000	0000000
		Year Ended December 31,	
	2011	**2010**	**2009**
Acquisition costs			
Proved properties	$ 324,191	$ 157,435	$ 251,976
Unproved properties	9	541	94,459
Exploration costs	15,085	19,357	10,531
Development costs	171,388	39,600	41,182
Asset retirement costs	56,745	65,951	23,291
Total costs incurred	$ 567,418	$ 282,884	$ 421,439

Capitalized Costs

The following table presents the aggregate capitalized costs relating to our oil and gas acquisition, exploration and development activities, and the aggregate related accumulated DD&A:

	00000000	00000000	00000000
		December 31,	
	2011	**2010**	**2009**
Unproved oil and gas properties	$ 135,591	$ 140,376	$ 178,073
Proved oil and gas properties	1,592,698	1,080,031	845,835
Accumulated depreciation, depletion and amortization	(528,965)	(356,695)	(164,347)
Capitalized costs, net	$ 1,199,324	$ 863,712	$ 859,561

The costs of unproved oil and gas properties are excluded from amortization until the properties are evaluated. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Unproved properties are assessed periodically, at least annually, to determine whether impairment has occurred. We assess properties on an individual basis or as a group if properties are individually insignificant. The assessment considers the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the associated costs are transferred to proved properties and are then subject to amortization. The transfer of costs into proved properties involves a significant amount of judgment and may be subject to changes over time based on our drilling plans and results, geological and geophysical evaluations, the assignment of proved reserves, availability of capital, and other factors. Costs not subject to amortization consist primarily of the estimated fair value of acquired unproved reserves. Due to the nature of the reserves, the ultimate evaluation of the properties will occur over a period of several years.

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

The following tables set forth the computation of the standardized measure of discounted future net cash flows (the Standardized Measure) relating to proved reserves and the changes in such cash flows of the Company s oil and gas properties in accordance with the FASB s authoritative guidance related to disclosures about oil and gas producing activities. The Standardized Measure is the estimated net future cash inflows from

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proved reserves less estimated future production and development costs, estimated plugging and abandonment costs, estimated future income taxes (if applicable) and a discount factor. Production costs do not include depreciation, depletion and amortization of capitalized acquisitions, exploration and development costs. Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the un-weighted arithmetic average first-day-of-the-month index prices for the preceding 12 months for proved reserves as of December 31, 2011, 2010 and 2009. These prices were $103.34/Bbl for oil and $4.48/MMBtu for natural gas at December 31, 2011; $79.40/Bbl for oil and $4.38/MMBtu for natural gas at December 31, 2010; and $61.04/Bbl for oil and $3.86/MMBtu for natural gas at December 31, 2009. These prices were adjusted by lease for quality, transportation fees, historical geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. Price changes based on inflation, federal regulatory changes and supply and demand are not considered. Estimated future production costs related to period-end reserves are based on period-end costs. Such costs include, but are not limited to, production taxes and direct operating costs. Inflation and other anticipatory costs are not considered until the actual cost change takes effect. In accordance with the FASB s authoritative guidance, a discount rate of 10% is applied to the annual future net cash flows. Future income taxes were calculated by applying the statutory federal income tax rate to pre-tax future net cash flows of properties owned by our taxable subsidiary, net of the tax basis of the properties involved and utilization of available tax carryforwards related to oil and gas operations.

The Standardized Measure is not intended to be representative of the fair market value of the proved reserves. The calculations of revenues and costs do not necessarily represent the amounts to be received or expended. Accordingly, the estimates of future net cash flows from proved reserves and the present value thereof may not be materially correct when judged against actual subsequent results. Further, since prices and costs do not remain static, and no price or cost changes have been considered, and future production and development costs are estimates to be incurred in developing and producing the estimated proved oil and gas reserves, the results are not necessarily indicative of the fair market value of estimated proved reserves, and the results may not be comparable to estimates disclosed by other oil and gas producers.

The Standardized Measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows:

	December 31,		
	2011	**2010**	**2009**
Future cash inflows	$ 4,142,460	$ 2,528,761	$ 1,414,485
Future production costs	(1,000,235)	(499,846)	(373,641)
Future development and abandonment costs	(677,603)	(511,596)	(450,839)
Future income tax expense	(97,035)	(30,106)	(29,113)
Future net cash flows	2,367,587	1,487,213	560,892
10% annual discount for estimated timing of cash flows	(540,915)	(302,695)	(85,254)
Standardized measure of discounted future net cash flows	$ 1,826,672	$ 1,184,518	$ 475,638

As of December 31, 2011, 2010 and 2009, 0%, 14%, and 22% of the Standardized Measure was attributable to noncontrolling interests in consolidated subsidiaries.

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A summary of the changes in the Standardized Measure of discounted future net cash flows applicable to proved oil and natural gas reserves for the three years ended December 31, 2011 is as follows:

	Year Ended December 31,		
	2011	**2010**	**2009**
Beginning of year	$ 1,184,518	$ 475,638	$ 254,706
Sales and transfers of oil and natural gas produced, net of production costs	(390,799)	(256,413)	(118,374)
Net changes in prices and production costs	301,750	383,400	48,305
Net changes in estimated future development costs	(87,249)	11,277	(6,435)
Extensions and discoveries		18,672	
Revisions of quantity estimates	172,144	157,489	29,079
Development costs incurred	144,567	99,983	45,652
Purchase and sales of reserves in place	440,165	231,933	191,268
Changes in production rates (timing) and other	(15,566)	(3,144)	(1,503)
Net change in income taxes	(43,798)	1,224	3,326
Accretion of discount	120,940	64,459	29,614
Net increase	642,154	708,880	220,932
End of year	$ 1,826,672	$ 1,184,518	$ 475,638

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DYNAMIC OFFSHORE RESOURCES, LLC

UNAUDITED PRO FORMA CONDENSED STATEMENT OF OPERATIONS

Year Ended December 31, 2011

(In thousands)

	Historical			
	Dynamic Offshore Resources, LLC	XTO Acquisition Properties	Pro Forma Adjustments	Pro Forma
Operating revenues	$ 520,782	$ 95,638	$	$ 616,420
Operating expenses:				
Lease operating expense	113,487	19,607		133,094
Exploration expense	15,085			15,085
Depreciation, depletion and amortization	173,585		29,872(a)	203,457
General and administrative expense	24,400			24,400
Other operating expense	77,505	4,125	2,494(a)	84,124
	404,062	23,732	32,366	460,160
Income (loss) from operations	116,720	71,906	(32,366)	156,260
Other income (expense):				
Interest expense, net	(9,503)		(3,504)(a)	(13,007)
Commodity derivative income	43,734			43,734
Bargain purchase gain	282			282
Other	(145)			(145)
Income (loss) before income taxes	151,088	71,906	(35,870)	187,124
Income tax benefit	5,359			5,359
Net income (loss)	156,447	71,906	(35,870)	192,483
Less: Net income attributable to noncontrolling interests	460			460
Net income (loss) attributable to Dynamic Resources, LLC	$ 155,987	$ 71,906	$ (35,870)	$ 192,023

See notes to unaudited pro forma condensed financial statements

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Dynamic Offshore Resources, LLC

Notes to Unaudited Pro Forma Condensed Financial Statements

Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Note 1 Basis of Presentation

The historical financial information is derived from the historical consolidated financial statements of Dynamic Offshore Resources, LLC for the year ended December 31, 2011 and the historical statements of revenue and direct operating expenses of the XTO Acquisition Properties for the eight months ended August 31, 2011. The unaudited pro forma condensed financial information has been prepared by applying pro forma adjustments to the historical audited financial statements of Dynamic Offshore Resources, LLC. The pro forma adjustments have been prepared as if our acquisition of the XTO Acquisition Properties had taken place as of January 1, 2011.

Note 2 Pro Forma Adjustments and Assumptions

Purchase of XTO Acquisition Properties

Our purchase of the XTO Acquisition Properties was completed on August 31, 2011. As a result, the acquisition is included in the historical financial statements of Dynamic Offshore Resources, LLC with effect from that date.

(a) Reflects our purchase of the XTO Acquisition Properties, including:

- depreciation, depletion and amortization expense and accretion expense based on our preliminary fair value determination and our closing date oil and gas reserve estimates;

- interest expense on $173.7 million in borrowings for the period from January 1, 2011 through August 31, 2011, at an estimated annual rate of approximately 3.0%. A one percentage point change in the interest rate would change pro forma interest expense by $1.2 million for the year ended December 31, 2011.

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Report of Independent Registered Public Accounting Firm

To the Board of Partners of

Dynamic Offshore Holding, LP

We have audited the accompanying statements of revenues and direct operating expenses of the XTO Acquisition Properties for the years ended December 31, 2010 and 2009. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the revenues and direct operating expenses of the XTO Acquisition Properties described in Note 1 for the years ended December 31, 2010 and 2009, in conformity with accounting principles generally accepted in the United States of America.

The accompanying financial statements reflect the revenues and direct operating expenses of the XTO Acquisition Properties as described in Note 1 and are not intended to be a complete presentation of the financial position, results of operations, or cash flows of the XTO Acquisition Properties.

Hein & Associates LLP

Houston, Texas

November 8, 2011

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XTO ACQUISITION PROPERTIES

STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

(In thousands)

	Six Months Ended June 30,		Year Ended December 31,	
	2011	2010	2010	2009
	(Unaudited)			
Oil and gas revenues	$ 67,793	$ 85,173	$ 154,367	$ 170,045
Direct operating expenses	17,006	19,419	37,530	37,862
Excess of revenues over direct operating expenses	$ 50,787	$ 65,754	$ 116,837	$ 132,183

See notes to statements of revenues and direct operating expenses

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XTO ACQUISITION PROPERTIES

Notes to Statements of Revenues and Direct Operating Expenses

Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Note 1 Properties and Basis of Presentation

The accompanying statements represent the interests in the revenues and direct operating expenses of the oil and natural gas producing properties acquired by Dynamic Offshore Holding, LP (the Partnership) from XTO Offshore Inc., HHE Energy Company and XH, LLC, each an indirect subsidiary of Exxon Mobil Corporation, (collectively, XTO) effective August 1, 2011. The Partnership paid $173.7 million for the properties. The properties are referred to herein as the XTO Acquisition Properties and are located in the Gulf of Mexico.

The statements of revenues and direct operating expenses have been derived from XTO s historical financial records and prepared on the accrual basis of accounting. Revenues and direct operating expenses relate to the historical net revenue interests and net working interests in the XTO Acquisition Properties. Oil, gas and condensate revenues are recognized on the sales method when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Revenues are reported net of overriding and other royalties due to third parties. Direct operating expenses include lease operating expenses, production and ad valorem taxes, transportation and all other direct operating costs associated with the properties. Direct operating expenses include $0.3 million and $6.5 million of insurance costs allocated by XTO for the years ended December 31, 2010 and 2009. For each of the six months ended June 30, 2011 and 2010, direct operating expenses include $0.1 million of insurance costs allocated by XTO. Direct operating expenses do not include corporate overhead, interest expense and income taxes.

The statements of revenues and direct operating expenses are not indicative of the financial condition or results of operations of the XTO Acquisition Properties going forward due to the omission of various operating expenses. During the periods presented, the XTO Acquisition Properties were not accounted for by XTO as a separate business unit. As such, certain costs, such as depreciation, depletion and amortization, accretion of asset retirement obligations, general and administrative expenses and interest expense were not allocated to the XTO Acquisition Properties.

Note 2 Omitted Financial Information

Historical financial statements reflecting financial position, results of operations and cash flows required by accounting principles generally accepted in the United States of America are not presented as such information is not available on a property-by-property basis, nor is it practicable to obtain such information in these circumstances. Historically, no allocation of general and administrative, interest expense, corporate taxes, accretion of asset retirement obligations, and depreciation, depletion and amortization was made to the XTO Acquisition Properties. Accordingly, the statements of revenues and direct operating expenses are presented in lieu of the financial statements required under Rule 3-01 and Rule 3-02 of the Securities and Exchange Commission s Regulation S-X.

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Supplemental Oil and Gas Reserve Information (Unaudited)

Except as noted within the context of each disclosure, the dollar amounts presented in the tabular data herein are stated in thousands of dollars.

Oil and Gas Reserve Information

The following tables summarize the net ownership interests in estimated quantities of proved and proved developed oil and natural gas reserves of the XTO Acquisition Properties for the periods indicated, estimated by the Partnership s petroleum engineers, and the related summary of changes in estimated quantities of net remaining proved reserves during the periods indicated.

	Crude oil (MBbl)	Natural gas (MMcf)
2009		
Proved Reserves		
Beginning balance	8,494	85,199
Production	(1,594)	(17,568)
Ending balance	6,900	67,631
Proved Developed Reserves, December 31, 2009	6,087	49,674
Proved Undeveloped Reserves, December 31, 2009	813	17,957
2010		
Proved Reserves		
Beginning balance	6,900	67,631
Production	(1,145)	(12,899)
Ending balance	5,755	54,732
Proved Developed Reserves, December 31, 2010	4,958	36,878
Proved Undeveloped Reserves, December 31, 2010	797	17,854

Proved reserves are estimated quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions (i.e., prices and costs) existing at the time the estimate is made. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells and equipment in place and under operating methods being utilized at the time the estimates were made.

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

The following tables set forth the computation of the standardized measure of discounted future net cash flows (the Standardized Measure) relating to proved reserves and the changes in such cash flows of the XTO Acquisition Properties in accordance with the Financial Accounting Standards Board s (FASB) authoritative guidance related to disclosures about oil and gas producing activities. The Standardized Measure is the estimated net future cash inflows from proved reserves less estimated future production and development costs, estimated plugging and abandonment costs, estimated future income taxes (if applicable) and a discount factor. Production costs do not include depreciation, depletion and amortization of capitalized acquisitions, exploration and development costs. Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the unweighted average of first-day-of-the-month commodity prices for the period and any fixed and determinable future price changes provided by contractual arrangements in existence at period end. Price changes based on inflation, federal regulatory changes and supply and demand are not considered. Estimated future production costs related to period-end reserves are based on period-end costs. Such costs include, but are not limited to, production taxes and direct operating costs. Inflation and other anticipatory costs are not considered until the actual cost change takes effect. In accordance with the FASB s authoritative guidance, a discount rate of 10% is applied to the annual future net cash flows.

In calculating the Standardized Measure, future net cash inflows were estimated by using the unweighted average of first-day-of-the-month oil and gas prices for the period with the estimated future production of period-end proved reserves and assume continuation of existing economic conditions. These prices were $79.40 per barrel of oil and $4.38 per MMBtu of natural gas at December 31, 2010 and $61.04 per barrel of oil and $3.86 per MMBtu of natural gas at December 31, 2009. The index prices have been adjusted for historical average location and quality differentials. Future cash inflows were reduced by estimated future development, abandonment and production costs based on period-end costs resulting in net cash flow before tax. Future income tax expense was not considered as the Partnership and the XTO Acquisition Properties are not tax-paying entities.

The Standardized Measure is not intended to be representative of the fair market value of the proved reserves. The calculations of revenues and costs do not necessarily represent the amounts to be received or expended. Accordingly, the estimates of future net cash flows from proved reserves and the present value thereof may not be materially correct when judged against actual subsequent results. Further, since prices and costs do not remain static, and no price or cost changes have been considered, and future production and development costs are estimates to be incurred in developing and producing the estimated proved oil and gas reserves, the results are not necessarily indicative of the fair market value of estimated proved reserves, and the results may not be comparable to estimates disclosed by other oil and gas producers.

	December 31,	
	2010	2009
Future cash inflows	$ 768,243	$ 766,742
Future production costs	(153,562)	(185,230)
Future development and abandonment costs	(178,912)	(192,601)
Future income tax expense		
Future net cash flows	435,769	388,911
10% annual discount for estimated timing of cash flows	(101,813)	(89,734)
Standardized measure of discounted future net cash flows	$ 333,956	$ 299,177

Changes in the Standardized Measure are as follows:

	Year Ended December 31,	
	2010	2009
Beginning of year	$ 299,177	$ 404,634
Sales of oil and natural gas, net of costs	(116,837)	(132,183)
Net changes in prices and production costs	90,295	(25,787)
Development costs incurred	13,689	28,962
Accretion of discount	25,678	33,988
Changes in timing and other	21,954	(10,437)
Net increase (decrease)	34,779	(105,457)
End of year	$ 333,956	$ 299,177

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

SANDRIDGE ENERGY, INC.

(Registrant)

Date: April 2, 2012

By: /s/ James D. Bennett
Name: James D. Bennett
Title: Executive Vice President and

Chief Financial Officer