BERRY PETROLEUM CO
Form 10-K
February 28, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K
S Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2012
Commission file number 1-9735
BERRY PETROLEUM COMPANY
(Exact name of registrant as specified in its charter)

DELAWARE	77-0079387
(State of incorporation or organization)	(I.R.S. Employer Identification Number)

1999 Broadway
Suite 3700
Denver, Colorado 80202
(Address of principal executive offices, including zip code)
Registrant's telephone number, including area code:
(303) 999-4400
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Class A Common Stock, $0.01 par value (including associated stock purchase rights)	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ý NO o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES o NO ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES ý NO o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES ý NO o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ý	Accelerated filer o	Non-accelerated filer o	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES o NO ý
As of June 30, 2012, the aggregate market value of the voting and non-voting common stock held by non-affiliates was $1,951,761,127.
As of February 25, 2013, the registrant had 52,547,120 shares of Class A Common Stock outstanding. The registrant also had 1,763,866 shares of Class B Stock outstanding on February 25, 2013, all of which is held by a single holder.
DOCUMENTS INCORPORATED BY REFERENCE

Part III is incorporated by reference from the registrant's definitive Proxy Statement for its Annual Meeting of Shareholders to be filed, pursuant to Regulation 14A, no later than 120 days after the close of the registrant's fiscal year.

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Forward Looking Statements

"Safe harbor under the Private Securities Litigation Reform Act of 1995:" Any statements in this Annual Report on Form 10-K that are not historical facts are forward-looking statements that involve risks and uncertainties. Words or forms of words such as "will," "might," "intend," "continue," "target," "expect," "achieve," "strategy," "future," "may," "could," "goal," "forecast," "anticipate," "estimate," or other comparable words or phrases, or the negative of those words, and other words of similar meaning, indicate forward-looking statements and important factors which could affect actual results. Forward-looking statements are made based on management's current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length in Part I, Item 1A. in this Annual Report on Form 10-K, under the heading "Risk Factors."

PART I

Item 1. Business

General

Berry Petroleum Company (which is identified as the “Company,” “we,” “us” or “our,” except where stated or the context requires otherwise) is an independent energy company engaged in the production, development, exploitation and acquisition of oil and natural gas. We were incorporated in Delaware in 1985. We have been publicly traded since 1987 and trace our roots in California oil production back to 1909. Since 2002, we have expanded our portfolio of assets through selective acquisitions driven by a consistent focus on properties with proved reserves and significant growth potential through low-risk development. Our principal reserves and producing properties are located in California (South Midway-Sunset (SMWSS)—Steam Floods, North Midway-Sunset (NMWSS)—Diatomite, NMWSS—New Steam Floods, Texas (Permian and E. Texas), Utah (Uinta) and Colorado (Piceance).

We operate in one industry segment, which is the production, development, exploitation and acquisition of oil and natural gas, and all of our operations are conducted in the continental United States. Consequently, we currently report a single industry segment. See Item 8. Financial Statements and Supplementary Data for financial information about this industry segment. Information contained in this Annual Report on Form 10-K reflects our business during the year ended December 31, 2012, unless noted otherwise.

Business Strategy

Our business strategy is to increase shareholder value by efficiently increasing production, reserves and cash flow, both through the drill bit and through acquisitions. We believe our inventory of drilling locations is ideally suited to growing production, reserves and cash flow due to predictable geology. Our strategy is based on the following:

- Pursuing the development of projects that we believe will generate attractive rates of return;
- Maintaining a balanced portfolio of long-lived oil and natural gas properties that provide stable cash flows;
- Maximizing production from our base oil assets;
- Selectively acquiring properties with an emphasis on oil; and
- Maintaining a strong financial position by investing our capital in a disciplined manner.

Business Strengths

We believe that the following strengths allow us to successfully execute our business strategy:

Low-Risk Multi-Year Drilling Inventory in Established Crude Oil Plays. We have a significant number of drilling locations in established crude oil plays that possess low geologic risk, leading to relatively predictable drilling results. Our complementary mix of primary development locations as well as heavy oil thermal projects provide high operating margins and the financial flexibility to respond to commodity price environments and localized operating environments.

Balanced High-Quality Asset Portfolio. Since 2002, we have grown our asset base and diversified our portfolio primarily through acquisitions in the Permian and Uinta. Our portfolio provides us with the flexibility to allocate capital among a diverse set of high-return oil assets.

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Long-Lived Proved Reserves with Stable Production Characteristics. Our properties generally have long reserve lives and reasonably stable and predictable well production characteristics. We have a ratio of proved reserves to production of approximately 21 years as of December 31, 2012.

Operational Control and Financial Flexibility. We exercise operating control over approximately 92% of our assets. We generally prefer to retain operating control over our properties, allowing us to more effectively control operating costs, timing of development activities and technological enhancements, marketing of production and allocation of our capital budget. In addition, the timing of most of our capital expenditures is discretionary, which allows us a significant degree of flexibility to adjust the size of our capital budget. We finance our drilling and development budget primarily through our internally generated operating cash flows.

Experienced Management and Operational Teams. Our core team of technical staff and operating managers has broad industry experience, including experience in heavy oil thermal recovery operations and unconventional reservoir development and completion. We continue to utilize technologies and steam practices that we believe will allow us to improve the ultimate recovery of crude oil on our California properties.

Acquisition and Divestiture Activities

The following sets forth our significant acquisitions and divestitures over the last several years:

2012 Acquisitions. In 2012, we acquired additional acreage near our core operating areas, including acreage in the Permian and contiguous to our Brundage Canyon and Lake Canyon assets, for an aggregate purchase price of approximately $78.3 million.

2012 Divestiture. In 2012, we sold our assets related to proved developed properties in Elko, Eureka and Nye Counties, Nevada (Nevada Assets) for approximately $15.6 million. We recorded a $1.6 million gain in conjunction with the sale.

2011 Acquisitions. In 2011, we made multiple acquisitions, each of which involved interests in properties located primarily in the Permian, for an aggregate purchase price of approximately $158.1 million.

2010 Acquisitions. In 2010, we made multiple acquisitions, each of which involved interests in properties located primarily in the Permian, for an aggregate purchase price of approximately $334.4 million.

Properties

The following table provides information regarding our operations by area as of December 31, 2012:

Name, State	Total Net Acres	Proved Reserves (MMBOE)(1)	Proved Developed Reserves (MMBOE)(1)	Proved Undeveloped Reserves (MMBOE)(1)	2012 Gross Wells(2)	2012 Net Wells(2)
S. Midway, CA	4,022	56.5	50.3	6.2	67	67
N. Midway—Diatomite, CA	841	55.3	32.6	22.7	120	120
N. Midway—New Steam Floods, CA	1,867	15.4	6.9	8.5	83	83
Permian, TX	60,187	63.0	21.5	41.5	91 (4)	74
Uinta, UT	121,545 (3)	36.8	16.2	20.6	106	87

E. Texas	4,649	13.4	13.4	—	—	—
Piceance, CO	8,077	34.7	9.3	25.4	—	—
Totals	201,188	275.1	150.2	124.9	467	431

(1) MMBOE—Million BOEs.
(2) Represents gross and net productive wells drilled during 2012.
(3) Excludes 49,000 undeveloped net acres subject to drill-to-earn agreements.
(4) Includes 17 non-operated wells in which we have an average interest of approximately 0.61% each, or approximately 0.10 total net wells, and 74 gross operated wells.

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The following table provides information regarding our production by area for the years ended 2012, 2011 and 2010:

	SMWSS(2)	NMWSS—Diatomite(2)	NMWSS—New Steam Floods(2)	Permian(3)	Uinta	E. Texas	Piceance(4)
Year Ended December 31, 2012							
Oil production (BOE/D)	12,823	3,255	1,827	5,548	3,677	210	53
Natural gas production (Mcf/D)	—	—	—	7,120	14,733	14,626	17,570
Total production (BOE/D)(1)	12,823	3,255	1,827	6,735	6,133	2,648	2,981
Year Ended December 31, 2011							
Oil production (BOE/D)	13,187	3,155	1,055	3,742	3,236	310	86
Natural gas production (Mcf/D)	—	—	—	4,082	13,836	24,108	23,472
Total production (BOE/D)(1)	13,187	3,155	1,055	4,422	5,542	4,328	3,998
Year Ended December 31, 2010							
Oil production (BOE/D)	13,597	2,722	805	1,084	3,048	395	62
Natural gas production (Mcf/D)	—	—	—	852	13,813	28,374	22,681
Total production (BOE/D)(1)	13,597	2,722	805	1,226	5,350	5,124	3,842

(1) Oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of oil.

(2) We consider our reserves in California, with the exception of those at our Placerita properties, to be within the San Joaquin Basin, which contained 15% or more of our total proved reserves in all years shown.

(3) We consider our reserves in the Permian to be within the Permian Basin, which contained 15% or more of our total proved reserves in 2012 and 2011.

(4) We consider our reserves in the Piceance to be within the Piceance Basin, which contained 15% or more of our total proved reserves in 2011 and 2010.

We currently have seven asset teams, as follows: SMWSS—Steam Floods, NMWSS—Diatomite, NMWSS—New Steam Floods, Permian, Uinta, E. Texas and Piceance.

SMWSS—Steam Floods. Our SMWSS—Steam Floods asset team includes our Homebase, Formax, Ethel D, Placerita and Poso Creek properties. Homebase, Formax, and Ethel D are located in the South Midway-Sunset Field, Poso Creek is located in the San Joaquin Valley and Placerita is located in Los Angeles County. These are our legacy assets, with production from Ethel D dating back to 1909, and we expect total average production to slowly decline over time. Production from these assets relies on thermal enhanced oil recovery (EOR) methods, including cyclic steaming and steam floods, to place steam effectively into the remaining oil column. In 2012, we continued drilling infill wells at

Homebase and Formax, drilling six horizontal wells at Homebase and two horizontal wells and two vertical wells at Formax. We had significant new development at Ethel D in 2012, including 41 new producing wells and five new steam injection wells. In 2012, we also drilled seven additional producing wells, four replacement wells and two additional steam injection wells at Poso Creek and continued our development of the Kraft reservoir at Placerita, drilling five new producing wells and recompleting 12 additional wells into either the upper or lower Kraft reservoir. In the third quarter of 2012, we also acquired approximately 100 net acres south of our Placerita leases. Average daily production from all SMWSS—Steam Floods assets in the fourth quarter of 2012 was approximately 13,070 BOE/D, a 3% increase from the third quarter of 2012.

NMWSS—Diatomite. Our NMWSS—Diatomite asset team includes our Diatomite properties in the San Joaquin Valley. We are continuing to refine our development approach, which includes modified high-frequency, reduced-temperature injection cycles, continuous development utilizing advanced drilling techniques and real-time performance monitoring. As a result of these efforts, reservoir dilation has decreased, which has reduced wellbore stresses. This strategy should increase the number of active completions, improve the recovery of the resource and enhance the long-term value of the Diatomite. In 2012, we drilled 94 new producing wells and 26 replacement wells, and expanded our infrastructure for the next phase of development. Average daily production from our NMWSS—Diatomite assets in the fourth quarter of 2012 was approximately 3,855 BOE/D, a 10% increase from the third quarter 2012.

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NMWSS—New Steam Floods. Our NWMSS—New Steam Floods asset team includes our non-Diatomite North Midway-Sunset assets including our McKittrick, Main Camp, Fairfield, Pan and USL-12 properties. At McKittrick, we continued to expand the steam flood in 2012, drilling 46 producing wells and 30 steam injection wells, and installing two additional steam generators to increase the McKittrick steam capacity to 22,000 barrels of steam per day. In 2012, we also drilled three vertical wells and two horizontal wells at Fairfield, drilled seven producing wells, one replacement well, and two steam injection wells at Pan and drilled 24 new producing wells at Main Camp. Average daily production from our NMWSS—New Steam Flood assets was approximately 2,130 BOE/D in the fourth quarter of 2012, an 11% increase from the third quarter of 2012.

Permian. In 2010, we established our initial position in the Permian by acquiring acreage in the Wolfberry trend, and we continued expanding our position through additional acquisitions in 2011 and the acquisition of an additional 19,000 net acres in or adjacent to the Wolfberry trend in 2012. We currently have working interests in approximately 60,000 net acres in the Permian, which includes approximately 32,000 net acres in the Wolfberry trend and approximately 28,000 net acres in Borden and Garza counties. In 2012, we drilled 74 gross (74 net) wells in the Wolfberry trend and a four-well appraisal project in Borden county. Early results from these appraisal wells were inconclusive for commercial quantities of oil, and we will continue to evaluate this acreage position. During 2012, we continued to experience natural gas plant curtailment in the Permian, resulting in back pressure, shut-in wells and ethane rejection, although we experienced some relief in the fourth quarter of 2012. Average daily production in the fourth quarter of 2012 was 7,965 BOE/D, a 16% increase from the third quarter of 2012.

Uinta. In 2003, we established our initial acreage position in the Uinta, targeting the Green River formation that produces both light oil and natural gas. We acquired the Brundage Canyon leasehold in Duchesne County in Northeastern Utah, which consists of working interests in federal, tribal and private leases. We also acquired working interests and exploratory rights in Lake Canyon, which is located immediately west of Brundage Canyon. In 2012, we acquired an additional 28,000 net acres in the Uinta, with the majority of the acreage being in or adjacent to Brundage Canyon and Lake Canyon. We currently have working interests in approximately 61,000 net acres in Brundage Canyon and Ashley National Forest, 36,500 net acres and exploratory rights in 49,000 net acres in Lake Canyon, and 9,000 net acres adjacent to Lake Canyon. In 2012, we drilled 102 gross (87 net) wells in the Uinta, including 27 gross (27 net) in Brundage Canyon, 27 gross (27 net) in Ashley National Forest and 48 gross (33 net) in Lake Canyon. Of the 102 gross wells drilled in 2012, 95 tested the Wasatch formation, with encouraging results. In addition to the 102 operated wells in the Uinta, we also participated in four non-operated Green River/Wasatch commingled wells with our partner in Lake Canyon. In June 2012, we received final US Forest Service approval on our Ashley National Forest Environmental Impact Study. As of December 31, 2012, we have 100% working interest in approximately 25,000 net acres in Ashley National Forest. Average daily production from our Uinta properties was approximately 7,500 BOE/D in the fourth quarter of 2012, a 26% increase from the third quarter of 2012.

E. Texas. In 2008, we acquired certain interests in natural gas producing properties in Limestone and Harrison Counties in E. Texas. The Limestone County assets include seven productive horizons in the Cotton Valley and Bossier sands at depths between 8,000 and 13,000 feet. Additional potential exists in the Haynesville/Bossier shale. The Harrison County assets include five productive sands as well as the Haynesville/Bossier Shale, with average depths between 6,500 and 13,000 feet. We deferred drilling in E. Texas during 2011 and 2012. Average daily production from our E. Texas assets was approximately 14 MMcf/D in the fourth quarter of 2012, a 7% decrease from the third quarter of 2012.

Piceance. In 2006, we acquired two properties in the Piceance targeting the Williams Fork section of the Mesaverde formation. We have a 62.5% working interest in 6,300 gross acres on our Garden Gulch property, a 95% working interest in 4,300 gross acres on our North Parachute property and a 5% non-operating working interest in 89 North Parachute wells. We have accumulated a sizable resource base, which should allow us to add significant proved reserves as we develop these assets. We deferred drilling in the Piceance in the second quarter of 2011 and 2012. Average daily production from our Piceance properties was approximately 16 MMcf/D in the fourth quarter of 2012, a 6% decrease from the third quarter of 2012.

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Reserves

The following table presents our estimated quantities of proved reserves as of December 31, 2012:

	Estimated Proved Reserves(2)		
	Oil (MBOE)	Natural Gas (MMcf)	Total (MBOE)(1)
Developed	118,937	187,668	150,216
Undeveloped	85,271	237,851	124,913
Total proved—December 31, 2012	204,208	425,519	275,129

(1) Oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of oil.
(2) At December 31, 2012, all of our oil and natural gas reserves are attributable to properties within the United States.

At December 31, 2012, our estimated proved undeveloped reserves (PUDs) were 124.9 MMBOE, a decrease of 4% compared to 130.1 MMBOE at December 31, 2011. During 2012, approximately 17.7 MMBOE, or 13.6%, of our December 31, 2011 PUDs were converted into proved developed reserves as a result of investing approximately $328.2 million of drilling, completion and facilities capital. As a result of the SEC's five year development limitation on PUDs we converted 36.0 MMBOE, or 27.7%, of our December 31, 2011 PUDs to unproved reserves primarily due to changes in timing of our PUD development plans. In 2012, we acquired 9.7 MMBOE of PUDs in Utah, California, and the Permian. In addition, our drilling and completion activities in 2012, primarily related to our California, Utah and Permian assets, and engineering revisions, resulted in the addition of approximately 38.8 MMBOE of PUDs. We intend to convert the PUDs disclosed as of December 31, 2012 to proved developed reserves within five years of the date they were initially disclosed as proved undeveloped.

Preparation of Reserves Estimates

Estimated proved reserves at December 31, 2012 were prepared by DeGolyer and MacNaughton (D&M), an independent petroleum engineering consulting firm that has provided consulting services throughout the world for over 70 years. See Exhibit 99.1—Report of DeGolyer and MacNaughton dated February 15, 2013.

Estimated proved reserves presented in the table above were calculated in accordance with SEC rules, which provide for estimated proved reserves to be based on a twelve-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the twelve-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. In addition, the SEC generally requires that reserves classified as proved undeveloped be capable of conversion into proved developed within five years of classification unless specific circumstances justify a longer time.

We maintain adequate and effective internal controls over the reserve estimation process. The reserves estimation process begins with our reserves coordinators, who are senior petroleum engineers and who are part of each asset team. The reservoir coordinators prepare, update and assemble information provided to D&M. Once all the relevant technical and support information has been assembled, D&M meets with our technical personnel to review field performance and future development plans. Following these reviews, D&M prepares independent reserve estimates and a final report based on the information we furnish to them. Our lead corporate reserve coordinator oversees and coordinates the reserve estimation process. She holds Bachelor and Master of Science degrees in Petroleum Engineering from the Colorado School of Mines. She has held numerous positions in the oil and gas industry over the last 30 years and has been primarily responsible for reserve evaluations for the last 20 years. Our reserve data and our reserve estimation process are reviewed by our senior management and a subcommittee of the Audit Committee of our Board of Directors.

The lead technical person at D&M primarily responsible for overseeing the preparation of our reserves is a Registered Professional Engineer in the State of Texas, is a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists and has over 35 years of experience in oil and natural gas reservoir studies and reserves evaluations.

There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. See Part I, Item 1A—"Risk Factors," for a description of some of the risks and uncertainties associated with our business and reserves.

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Productive Wells and Acreage

As of December 31, 2012, we had working interests in 2,744 gross (2,584 net) productive oil wells and 455 gross (271 net) productive natural gas wells. Productive wells include both producing wells and shut-in wells that are capable of producing.

The following table sets forth information with respect to our developed and undeveloped acreage as of December 31, 2012. Developed acreage is comprised of leased acres that are within an area spaced by or assignable to a productive well. Gross acreage represents acres in which we have a working interest, and net acreage represents our aggregate working interests in the gross acres.

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
California	6,451	5,984	833	746	7,284	6,730
Colorado	1,610	1,131	9,052	6,946	10,662	8,077
Texas	16,760	13,803	58,040	51,033	74,800	64,836
Utah(1)	28,120	26,574	154,855	94,971	182,975	121,545
Wyoming	3,400	497	—	—	3,400	497
Total	56,341	47,989	222,780	153,696	279,121	201,685

(1) Excludes 49,000 net undeveloped acres subject to drill-to-earn agreements.

Future Acreage Expirations

If production is not established or we take no other action to extend the terms of the related leases, undeveloped acreage will expire over the next three years as follows:

	2013		2014		2015	
	Gross	Net	Gross	Net	Gross	Net
Utah(1)	15,251	4,722	518	864	23,190	13,064
Texas(1)	986	1,108	33,698	18,159	3,254	11,128
Total	16,237	5,830	34,216	19,023	26,444	24,192

(1) Expiring net acreage may be greater than expiring gross acreage when multiple undivided interests in the same gross acreage expire at different times.

Our investment in developed and undeveloped acreage comprises numerous leases. The terms and conditions under which we maintain exploration or production rights to the acreage are property-specific, contractually defined and vary significantly from property to property. Work programs are designed to ensure that the exploration potential of any property is fully evaluated before expiration. In some instances, we may elect to relinquish acreage in advance of the contractual expiration date if the evaluation process is complete and there is not a business basis for extension. In cases where additional time may be required to fully evaluate acreage, we have generally been successful in obtaining extensions. We currently intend to reduce the majority of our 2013 acreage expirations, either through development or through extension.

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Drilling Activity

The following table sets forth our drilling activities for the following periods:

	Year Ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development wells drilled:						
Productive	467 (1)	431	404 (2)	367	241	232
Dry	3	3	4	4	—	—
Exploratory wells drilled:						
Productive	—	—	—	—	—	—
Dry	5	5	—	—	1	1
Total wells drilled:						
Productive	467 (1)	431	404 (2)	367	241	232
Dry	8	8	4	4	1	1

(1) Includes 17 non-operated Permian wells in which we have an average interest of approximately 0.61% each, or approximately 0.10 total net wells,

(2) Includes 25 non-operated Permian wells in which we have an average interest of approximately 0.67% each, or approximately 0.2 total net wells.

We achieved a gross drilling success rate of 98.3%, 99.0% and 99.6% for the years ended December 31, 2012, 2011 and 2010, respectively. Gross drilling success represents the percentage of gross wells drilled that were not dry wells (defined as a well incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well).

As of December 31, 2012, we had eight rigs drilling on our properties and we had five gross (five net) wells in progress.

Marketing and Customers

We market the majority of the oil and natural gas production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our production to a variety of purchasers under oil and natural gas purchase contracts with daily, monthly, seasonal, annual or multi-year terms, all at market prices. The majority of our sales are to marketing companies or refiners. We typically sell production to a relatively small number of customers.

For the year ended December 31, 2012, sales to ExxonMobil Oil Corporation (Exxon), Shell Trading (US) Company (Shell), Enterprise Crude Oil LLC (Enterprise) and HollyFrontier Corporation (Holly) accounted for approximately 43%, 13%, 9% and 9%, respectively, of our revenue. Our contract with Shell continues through June 30, 2013, and our contract with Exxon continues through August 31, 2014, and then renews automatically on a month-to-month basis unless either party to the contract terminates upon 60 days' notice. Our contract with Enterprise continues through April 30, 2013, and our contract with Holly for the sale of 5,000 Bbl/D continues through June 30, 2013. Before a sales contract in a given area expires, we generally allow potential purchasers to bid for a contract to purchase our oil in the area, and select the contract most beneficial to our business. However, new contracts may not be obtained on a timely basis or on terms beneficial to our business. Based on the current demand for oil and natural gas and the availability of other purchasers, we believe that, with the exception of our primary customer in Utah, the loss of any one of our major purchasers would not have a material adverse effect on our financial condition, results of operations and operating cash flows.

Refinery constraints in the Utah region, coupled with our increased production in the area, have impacted the immediate marketability of a portion of our Utah production and have caused us to pursue alternate transportation methods and sales outlets. Beginning in 2013, these constraints have caused us to initiate measures to reduce production, such as shutting in some of our wells and postponing completions of some of our newly drilled wells. We may not be successful in securing alternative sales outlets for our Utah production. Shutting in or delaying Utah oil production and selling or transporting Utah oil to different customers or in different markets could result in increased costs and have an adverse impact on our production growth and margins. See Item 1A. Risk Factors—"Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production."

Oil. Our oil production is collected in tanks and sold via pipeline or truck. Approximately 49% of our total production is attributable to our California heavy crude (generally 21 degree API gravity crude oil or lower). Our California heavy crude is sold at local posted prices, which differ from established market indices due primarily to the higher refining costs associated with heavy crude and differences in supply origin at domestic refineries. In the Permian, our oil is sold to oil marketing

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companies, and is priced using a formula that is based on WTI and includes adjustments for location differentials and transportation costs, generally resulting in a sales price below WTI. Utah waxy crude is difficult to transport and has historically been confined primarily to the Salt Lake City market, which is largely dependent on supply and demand of waxy crude in the area. Our Utah oil is generally sold to Holly at a fixed percentage discount to WTI or to another refiner based on local posted prices.

Natural Gas. Our natural gas is sold based upon localized index pricing. Our natural gas production in the Piceance is priced based on the Clarington, Ohio index or the Malin, Oregon index. Our natural gas production in Utah is generally priced relative to a Rocky Mountain Northwest Pipeline (NWPL) or Questar index price. Our natural gas production in E. Texas is generally priced based on the Florida Zone 1 or the Natural Gas Pipeline Co. of America-Texok zone index. Our natural gas produced in the Permian is priced at a discount to the El Paso Permian index.

Our natural gas is transported through our own and third-party gathering systems and pipelines. We incur processing, gathering and transportation expenses to move our natural gas from the wellhead to a purchaser-specified delivery point. These expenses vary based on the volume, distance shipped and the fee charged by the third-party processor or transporter. In certain instances, we enter into firm transportation contracts on interstate and intrastate pipelines to assure the delivery of our natural gas to market. These commitments generally require a minimum monthly charge regardless of whether the contracted capacity
is used or not. Currently, our natural gas production is insufficient to fully utilize our contracted capacity on the Rockies Express, Wyoming Interstate and Ruby pipelines. In California, we have firm transportation contracts to assure our ability to purchase a portion of our consumed natural gas outside of the California markets. The following table sets forth information about material long-term firm transportation contracts for pipeline capacity as of December 31, 2012:

Pipeline	From	To	Quantity (Avg. MMBtu/D)	Term	Demand charge per MMBtu		Remaining contractual obligation (in thousands)
Kern River Pipeline	Opal, WY	Kern County, CA	12,000	5/2003 to 4/2013	$0.58		$852
Rockies Express Pipeline	Meeker, CO	Clarington, OH	25,000	2/2008 to 1/2018	1.13	(1)	52,601
Rockies Express Pipeline	Meeker, CO	Clarington, OH	10,000	6/2009 to 11/2019	1.09	(1)	27,406
Questar Pipeline	Brundage Canyon, UT	Salt Lake City, UT	2,500	9/2003 to 2/2013	0.17	(2)	16
Questar Pipeline	Brundage Canyon, UT	Salt Lake City, UT	2,859	9/2003 to 2/2013	0.17	(2)	19
Questar Pipeline	Brundage Canyon, UT	Goshen, UT	5,000	9/2003 to 10/2022	0.26		4,618
Questar Pipeline	Chipeta Plant, UT	Various UT locations	6,200	7/2012 to 6/2020	0.17	(2)	3,165
Questar Pipeline	Chipeta Plant, UT	Various UT locations	2,550	12/2012 to 8/2013	0.17		108
Questar Pipeline	Chipeta Plant, UT	Various UT locations	15,640	9/2013 to 8/2023	0.17		9,925
Enbridge Pipeline		Orange, TX	14,940		0.10		761

	Limestone and Harrison Counties, TX			7/2012 to 6/2014		
Wyoming Interstate Company Pipeline	Meeker, CO	Opal, WY	35,000	8/2011 to 7/2021	0.31	35,536
Ruby Pipeline	Opal, WY	Malin, OR	35,000	8/2011 to 7/2021	0.95	110,072
Total						$245,079

(1) Based on weighted average cost.
(2) The planned expansion of the Chipeta Processing LLC natural gas plant was completed in February 2013, at which time transportation ceased under some related contracts and began under others.

Steaming Operations

Our California assets consist of heavy crude oil, which requires heat, supplied in the form of steam, injected into the oil producing formations to reduce the oil viscosity, thereby allowing the oil to flow to the wellbore for production. We utilize cyclic steam and/or steam flood recovery methods on such assets.

Cogeneration Steam Supply. In pursuing our goal of being a cost-efficient heavy oil producer in California, we have consistently focused on minimizing our steam cost. We believe one of the main methods to keep steam costs low is through the ownership and efficient operation of three cogeneration facilities located on our properties. These cogeneration facilities are all located on our SMWSS properties, including our 38 megawatt (MW) and 18 MW facilities at Homebase and our 42 MW facility at Placerita. Cogeneration, also called combined heat and power (CHP), extracts energy from the exhaust of a turbine

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that would otherwise be wasted to produce steam. This increases the efficiency of the combined process and consumes less fuel than would be required to produce the steam and electricity separately.

Conventional Steam Generation. We also own 49 fully permitted conventional steam generators. The quantity of generators operated at any point in time is dependent on (i) the steam volume required to achieve our targeted production and (ii) the price of natural gas compared to the realized price of crude oil sold. In 2012, we added ten additional steam generators including two for use at our McKittrick property, one for use at our Main Camp property and seven for use in our ongoing development of our Diatomite assets. In 2011, we added five additional steam generators, four for use in the development of our Diatomite property and one for use at our McKittrick property. In 2010, we added four additional steam generators for use in the development of our Diatomite assets.

Ownership of these varied steam generation facilities and sources allows for maximum operational control over the steam supply, location and, to some extent, the aggregated cost of steam generation. Our steam supply and flexibility are crucial for the maximization of California thermally enhanced heavy oil production, cost control and ultimate oil recovery.

Total steam capacity, measured in barrels of steam per day (BSPD), as of December 31, 2012 was as follows:

Steam generation capacity of conventional steam generators	213,911
Steam generation capacity of cogeneration plants	42,789
Additional steam purchased under contract with a third party	954
Total steam capacity	257,654

The average gross volume of steam injected in our California oil production operations for the years ended December 31, 2012 and 2011 was 170,884 BSPD and 133,404 BSPD, respectively.

During December 2012, approximately 85% of the natural gas we purchased to generate steam and electricity was based upon California indices. We pay distribution/transportation charges for the delivery of natural gas to our various locations where we use the natural gas for steam generation purposes. In some cases, this transportation cost is embedded in the price of the natural gas we purchase. Approximately 15% of the volume of natural gas purchased to generate steam and electricity was purchased in the Rockies and moved to the Midway-Sunset field using our firm transportation capacity on the Kern River Pipeline. This natural gas has historically been purchased based upon the Rocky Mountain NWPL index. Historical average prices of the natural gas indices key to our steaming operations are as follows:

	2012	2011	2010
Average SoCal Border Monthly Index Price per MMBtu	$3.00	$4.10	$4.34
Average PG&E Citygate Monthly Index Price per MMBtu	3.16	4.29	4.66
Average Rocky Mountain NWPL Monthly Index Price per MMBtu	2.68	3.80	3.94

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Historically we have been a net producer of natural gas and have benefited operationally when natural gas prices increase. Our production of natural gas provides a form of natural hedge against rising steam costs. As our natural gas production continued to decrease and our use of natural gas for steaming operations has increased, we have become a net consumer of natural gas. The following table shows our average and estimated average amount of production, consumption and hedged volumes for the following years:

(in MMBtu/D)	Estimated 2013	2012	2011
Natural gas produced	47,136	54,054	65,500
Natural gas consumed in operations			
Cogeneration operations	26,600	26,625	25,087
Conventional steam generators	62,000	43,330	34,377
Total natural gas consumed in operations	88,600	69,955	59,464
Less: Estimated natural gas volumes consumed to produce electricity(1)	(15,400)	(15,415)	(15,229)
Net estimated natural gas consumed in steam generation	73,200	54,540	44,235
Natural gas (purchases) sales volumes hedged(2)	(10,000)	10,000	15,000
Estimated net (deficit) excess of natural gas produced, consumed and hedged	(16,064)	(10,486)	6,265

(1) Estimate is based on the historical allocation of fuel costs to electricity.

(2) Beginning in 2013, our natural gas derivatives hedge against rising natural gas prices; in years previous to 2013, our natural gas derivatives hedged against falling natural gas prices.

Electricity

Generation. The total net electrical generation capacity of our three cogeneration facilities during 2012 was approximately 93 MW, of which we consumed approximately 8 MW for use in our operations. Each facility is centrally located on certain of our oil producing properties. Thus the steam generated by each facility is capable of being delivered to numerous wells that require steam for the EOR process. Our investment in our cogeneration facilities has been for the express purpose of lowering the steam costs in our heavy oil operations and securing operating control of the respective steam generation. Expenses of operating the cogeneration plants are analyzed regularly to determine whether they are advantageous versus conventional steam generators. Cogeneration costs are allocated between electricity generation and oil and natural gas operations based on the conversion efficiency (of fuel to electricity and steam) of each cogeneration facility and certain direct costs to produce steam. Cogeneration costs allocated to electricity will vary based on, among other factors, the thermal efficiency of our cogeneration plants, the price of natural gas used for fuel in generating electricity and steam and the terms of our power contracts. Although we account for cogeneration costs as described above, economically we view any profit or loss from the generation of electricity as a decrease or increase, respectively, to our total cost of producing heavy oil in California. Depreciation, depletion and amortization (DD&A) related to our cogeneration facilities is allocated between electricity operations and oil and natural gas operations using a similar allocation method.

Sales Contracts. We sell electricity produced by our cogeneration facilities under long-term contracts approved by the California Public Utilities Commission (CPUC) to two California investor owned utilities (IOUs): Southern California Edison Company (Edison) and Pacific Gas and Electric Company (PG&E). Under these power purchase agreements (PPAs), we are paid an energy payment that reflects the utility's Short Run Avoided Cost (SRAC) of energy plus a capacity payment that reflects a recovery of capital expenditures that would otherwise have been made by the utility. Beginning in 2015, the energy prices we will be paid under the contracts for our Cogen 18 and Cogen 38 facilities will be based on market prices for electricity in California.

Our legacy PPAs for our Cogen 42 facilities expired in May 2012, at which time a transition PPA with Edison became effective. On July 2, 2012, we and Edison executed a seven-year contract for our Cogen 42 facilities pursuant to a competitive solicitation (the RFO PPA). Subject to CPUC approval, the seven-year term will commence on July 1, 2014, at which time the transition PPA for Cogen 42 will terminate.

Our legacy PPA for our Cogen 38 facility expired in March 2012, at which time a transition PPA with PG&E became effective. We intend to participate in future CHP competitive solicitations for the sale of energy and capacity from our Cogen 38 facility, although there is no assurance we will be successful in entering into a new RFO PPA for this facility. Our transition PPA with PG&E will remain in effect until June 2015.

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Our legacy PPA with PG&E for our Cogen 18 facility terminated on September 30, 2012 and was replaced with a new Public Utilities Regulatory Policy Act of 1978, as amended (PURPA) PPA with PG&E, effective October 1, 2012, for a term of seven years. Because the rated capacity of our Cogen 18 facility is less than 20 MW, it continues to be eligible for PPAs pursuant to PURPA.

Under the PURPA PPA for our Cogen 18 facility and the transition PPAs for our Cogen 38 and Cogen 42 facilities, we will be paid the CPUC-determined SRAC energy price and a combination of firm and "as-available" capacity payments. Under the RFO PPA for our Cogen 42 facility, which will commence July 1, 2014, we will be paid a negotiated energy and capacity price stipulated in the contract.

See Item 1A. Risk Factors—"We are dependent on our cogeneration facilities and deteriorations in the electricity market and regulatory changes in California may materially and adversely affect our financial condition, results of operations and operating cash flows."

The following table sets forth information regarding our cogeneration facilities and contracts as of December 31, 2012:

Facility	Type of Contract	Purchaser	Contract Expiration		Approximate Megawatts Available for Sale(3)	Approximate Megawatts Consumed in Operations(3)	Approximate Barrels of Steam Per Day in 2012
Cogen 42	Transition	Edison	June 2015	(1)	37	4	13,000
Cogen 18	PURPA	PG&E	Sept 2019		11	4	6,500
Cogen 38	Transition	PG&E	June 2015	(2)	37	—	18,000

(1) Subject to CPUC approval, we have executed a seven-year contract with Edison that will commence on July 1, 2014, which will replace the current Transition contract.
(2) We anticipate the current transition contract will be replaced by a long-term contract with a term of up to seven years pursuant to a future competitive solicitation.
(3) Assumes operations at full capacity with no interruptions.

Competition

The oil and natural gas industry is highly competitive. As an independent producer, we have little control over the price we receive for our oil and natural gas. As such, higher costs, fees and taxes assessed at the producer level cannot necessarily be passed on to our customers. In acquisition activities, competition is intense as integrated and independent companies and individual producers are active bidders for desirable oil and natural gas properties and prospective acreage. Although many of these competitors have greater financial and other resources than we have, we are in a position to compete effectively due to our business strengths.

Title to Properties

Prior to the time we acquire undeveloped properties, we conduct a title investigation consistent with industry custom and practice. Most developed properties we acquire have existing title opinions. In addition, prior to commencement of drilling operations we obtain a drilling title opinion which, in the event production is achieved, is supplemented with a division order title opinion or its equivalent. To date, we have obtained or commissioned title opinions on virtually all of our producing properties and have satisfactory title to those properties in accordance with industry standards. A majority of our oil and natural gas properties are subject to a mortgage or deed of trust under our senior secured revolving credit facility (credit facility), as well as to customary royalty interests, liens incidental to operating agreements, tax liens and other minor burdens, encumbrances, easements and restrictions that do not materially interfere with the use of or affect the value of such properties.

Employees

As of December 31, 2012 we had 374 full-time employees. We also contract for the services of independent consultants involved with land, regulatory, accounting, financial and other disciplines as needed. None of our employees are represented by labor unions or covered by a collective bargaining agreement. Our relations with our employees are good.

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Offices

Our corporate headquarters are located in Denver, Colorado, and we have regional offices in Bakersfield, California, Plano, Texas and Midland, Texas.

Available Information

Our website, located at http://www.bry.com, can be used to access recent news releases and SEC filings, crude oil price postings, hedging summaries, our Annual Report, Proxy Statement, Board Committee Charters, Corporate Governance Guidelines, Code of Business Conduct and Ethics, the Code of Ethics for Senior Financial Officers and other items of interest. Information on our website is not incorporated into this report. SEC filings, including supplemental schedules and exhibits, can also be accessed free of charge through the SEC website at http://www.sec.gov.

Environmental Matters and Other Regulations

General. Our operations are subject to stringent, complex and evolving federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Our operations are subject to the same environmental laws and regulations as other companies in the oil and natural gas exploration and production industry. These laws and regulations:

- require the acquisition of various permits or authorizations before drilling commences;
- require the installation of expensive pollution control equipment;
- require the purchase of emissions allowances and offsets for the emission of greenhouse gases above the amount of allowances granted to us;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- require groundwater quality sampling and monitoring;
- limit or prohibit drilling activities on lands lying within environmentally sensitive areas, wilderness, wetlands and other protected areas;
- affect the location and size of our wells and facilities;
- require measures to prevent pollution from former operations, such as pit closure and plugging of abandoned wells;
- impose substantial liabilities for pollution resulting from our operations; and
- require time-consuming environmental analyses with uncertain outcomes.

Failure to comply with these laws and regulations may result in the assessment of significant administrative, civil, or criminal penalties, imposition of remedial obligations, incurrence of additional compliance costs and operational delays or injunctions.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost and timing of doing business and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise the environmental laws and regulations, and any changes that result in delay of oil and natural gas operations or more stringent and costly permitting, well drilling, construction, completions and water management activities, or waste handling, disposal and clean-up requirements for the oil and natural gas industry could materially and adversely affect our financial condition, results of operations and operating cash flows.

We believe that, in all material respects, we are in compliance with, and have complied with, all applicable environmental laws and regulations. We employ an environmental health and safety department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental guidelines and safety precautions. We have made and will continue to make expenditures in our efforts to comply with all environmental regulations and requirements. We consider these a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with governmental regulations. We believe that our continued compliance with existing requirements has been accounted for and will not have a material and adverse impact on our financial condition, results of operations and operating cash flows. However, because environmental laws and regulations are subject to frequent changes, we are unable to predict the impact that compliance with future laws or regulations may have on our future financial condition, results of operations or operating cash flows. For the year ended December 31, 2012, we did not incur any material capital expenditures for remediation or retrofit of pollution control equipment at any of our facilities. As of the date of this report, we are not aware of any environmental issues or claims that will require material capital expenditures during the next 12 months.

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Some of the more significant environmental laws and regulations that could have a material impact on the oil and natural gas exploration and production industry and our business are as follows:

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (NEPA). NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will have an environmental assessment prepared that assesses the potential direct, indirect and cumulative impacts of a proposed project and alternatives to the proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study that is made available for public review and comment. All of our current exploration and production activities on federal lands, as well as proposed exploration and development plans on federal lands, require governmental permits that may trigger the requirements of NEPA. Certain federal permits on non-federal lands may also trigger NEPA requirements. This process has the potential to delay or limit the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Waste Handling. The Resource Conservation and Recovery Act (RCRA) and comparable state laws regulate the generation, transportation, treatment, storage, disposal and cleanup of “hazardous wastes” and the disposal of non-hazardous wastes. RCRA imposes stringent operating requirements and liability for failure to meet such requirements on "generators" or "transporters" of waste or "owners" or "operators" of a waste treatment, storage or disposal facility. Under the auspices of the Environmental Protection Agency (EPA), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of oil, natural gas, or geothermal energy constitute “solid wastes,” which are regulated under the less stringent, non-hazardous waste provisions; however, there is no guarantee that the EPA or the individual states will not adopt more stringent requirements for the handling of these non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration and production wastes as “hazardous wastes.” Any modification of state or federal laws that would cause oil and natural gas exploration and production wastes to be classified as hazardous would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses, and could have a material adverse effect on our results of operations and financial position.

Our operations produce wastewater some of which is disposed via injection in underground wells. These wells are regulated under the Safe Drinking Water Act (SDWA) and similar state and local laws. The underground injection well program under the SDWA requires permits from the EPA or analogous state agencies for our disposal wells, establishes minimum standards for injection well operations and restricts the types and quantities of fluids that may be injected. A change in the regulations or the inability to obtain permits for new injection wells in the future may affect our ability to dispose of produced waters and ultimately increase the cost of our operations.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the “Superfund” law, along with comparable state laws, impose strict, joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for a release or threatened release of a “hazardous substance” into the environment. These persons include the current and past owners or operators of the disposal site, or site where the release or threatened release of a “hazardous substance” occurred, and entities that disposed or arranged for the disposal of the hazardous substance. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years, and substances that could be subject to CERCLA and analogous state laws may have been released on or under these properties or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of substances that could be subject to CERCLA and similar state laws was not under our control. Therefore, governmental agencies or third parties may seek to hold us jointly and severally liable under CERCLA or comparable state laws for all or part of the costs to remove such previously disposed substances, remediate contaminated property or perform remedial operations to prevent future contamination at sites at which such substances have been released.

OSHA and Other Laws and Regulation. We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state laws. Pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety. Additionally, the

OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations.

Water Discharges. The federal Water Pollution Control Act (Clean Water Act) and comparable state laws impose restrictions and strict controls with respect to the discharge of pollutants, including produced waters and spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Oil Pollution Act. The Oil Pollution Act of 1990 (“OPA”) and regulations issued under OPA impose strict, joint and several liability on “responsible parties” for removal costs and damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A “responsible party” includes the owner or operator of an onshore facility. OPA establishes a liability limit for onshore facilities of $350.0 million per spill. This limit does not apply if the spill is caused by a responsible party’s gross negligence or willful misconduct; the spill resulted from a responsible party’s violation of a federal safety, construction or operating regulation; or a responsible party fails to report a spill or to cooperate fully in a cleanup. The President may increase the amount of financial responsibility required under OPA by up to $150.0 million, depending on the risk represented by the quantity or quality of oil that is handled by the facility. Any failure to comply with OPA’s requirements or inadequate cooperation during a spill response action may subject a responsible party to administrative penalties up to $25,000 per day per violation.

Air Emissions. The federal Clean Air Act (CAA) and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of monitoring, reporting and other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. These laws and the implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations.

Climate Change. In December 2009, the EPA determined that emissions of carbon dioxide, methane and other “greenhouse gases” (GHGs) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. The EPA has adopted two sets of rules regulating GHG emissions under the CAA, one that requires a reduction in emissions of GHGs from motor vehicles and the other that regulates emissions of GHGs from certain large stationary sources under the CAA's Prevention of Significant Deterioration and Title V permitting programs. The EPA's rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent the EPA from implementing, or requiring state environmental agencies to implement, the rules. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among other things, certain onshore oil and natural gas production facilities, on an annual basis. Legislation has from time to time been introduced in the United States Congress that would establish measures restricting GHG emissions in the United States. At the state level, almost one half of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs. See "California GHG Regulations" below for more detail on current GHG regulations in the state of California.

California GHG Regulations. In October 2006, California adopted the Global Warming Solutions Act of 2006 (Assembly Bill 32), which established a statewide "cap and trade" program with an enforceable compliance obligation beginning with 2013 GHG emissions. The program is designed to reduce the state's GHG emissions to 1990 levels by 2020. Assembly Bill 32 will set maximum limits or caps on total emissions of GHGs from all industrial sectors, including the oil and natural gas extraction sector of which we are a part, as our California heavy oil operations emit GHGs. The cap will decline annually thereafter through 2020. We will be required to remit compliance instruments for each metric ton of GHG that we emit, in the form of allowances (each the equivalent of one ton of carbon dioxide) or qualifying offset credits. The availability of allowances will decline over time in accordance with the declining cap, and the cost to acquire such allowances may increase over time. Under Assembly Bill 32, we will be granted a certain number of California Carbon Allowances (CCAs) and we will need to purchase CCAs and/or offset credits to cover the remaining amount of our emissions. Compliance with Assembly Bill

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32 could significantly increase our capital, compliance, operating and maintenance costs and could also reduce demand for the oil and natural gas we produce. We continue to assess the impact of these regulations on our operations, including the cost to acquire allowances and to reduce emissions. Our current estimates indicate that, based on the current market price of allowances, the manner in which cost-free allowances are to be distributed by the California Air Resources Board to the oil and natural gas extraction industry and our current production and emissions estimates, among other factors, our cost of acquiring compliance instruments beginning in 2013 may be in the range of $1.00 to $2.50 per barrel of California production. The actual cost to acquire compliance instruments will depend on the market price for such instruments at the time they are purchased, the distribution of allowances among various industry sectors and our ability to limit our GHG emissions and implement cost-containment measures. The cap and trade program is currently scheduled to be in effect through 2020, although it may be continued thereafter.

Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that involves the injection of water, sand and chemicals under pressure into the formation to fracture the rock and stimulate production of hydrocarbons. We routinely utilize hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and natural gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the SDWA and has released draft permitting guidance documents related to this newly asserted regulatory authority. In addition, on November 23, 2011, the EPA announced that it was granting in part a petition to initiate a rulemaking under the Toxic Substances Control Act relating to chemical substances and mixtures used in oil and natural gas exploration and production. Moreover, legislation has been introduced before Congress to repeal an exemption in the federal SDWA for the underground injection of hydraulic fracturing fluids near drinking water sources. If adopted, the legislation would require the reporting and public disclosure of chemicals used in the fracturing process. Further, if enacted, the legislation could result in additional regulatory burdens such as permitting, construction, financial assurance, monitoring, recordkeeping and plugging and abandonment requirements.

We use a significant amount of water in our hydraulic fracturing operations. Our inability to locate sufficient amounts of usable water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

Certain states in which we operate, including Texas and Colorado, have adopted, and other states, including California, are considering adopting, regulations that could impose increased regulatory oversight of hydraulic fracturing through additional permit requirements, public disclosure, operational restrictions and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. For example, the Railroad Commission of Texas adopted rules in December 2011 requiring disclosure of certain information regarding the components used in the hydraulic fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local or municipal legal restrictions are adopted in areas where we are currently conducting or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. The EPA released a progress report outlining work currently underway on December 21, 2012 and is expected to release results of the study in 2014. In addition, the EPA announced on October 20, 2011 that it is launching a study of wastewater resulting from hydraulic fracturing activities and currently plans to propose pretreatment regulations by 2014. Also, certain members of the Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or otherwise. President Obama created the Interagency Working Group on Unconventional Natural Gas and Oil by Executive Order on April 13, 2012, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources.

Further, on August 16, 2012, the EPA published final rules that establish new air emission control requirements for natural gas production, processing and transportation activities, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, and National Emission Standards for Hazardous Air Pollutants (NESHAPS) to address hazardous air pollutants frequently associated with gas production and processing activities. Among other things, these final rules require the reduction of volatile organic compound emissions from natural gas wells through the use of reduced emission completions or “green completions” on all hydraulically fractured wells constructed or refractured after January 1, 2015. In addition, gas wells are required to use completion combustion device equipment (i.e., flaring) by October 15, 2012 if emissions cannot be directed to a gathering line. Further, the final rules under NESHAPS include maximum achievable control technology (MACT) standards for “small” glycol dehydrators that are located at major sources of hazardous air pollutants and modifications to the leak detection standards for valves.

The adoption of any future federal or state laws or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to perform hydraulic fracturing, complete natural gas wells in shale formations and obtain permits, and could increase our costs of compliance and doing business. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves, and could materially and adversely affect our financial condition, results of operations and operating cash flows.

Endangered Species. The Endangered Species Act (ESA) may restrict activities that may affect endangered and threatened species or their habitats. Some of our facilities and drilling operations are located in areas that are designated as habitat for endangered or threatened species; therefore, we may be prohibited from conducting drilling operations in certain locations or during certain seasons, such as breeding or nesting seasons, when our operations could have an adverse effect on the species. The presence of a protected species or the designation of previously unprotected species in our operating areas as threatened or endangered could impair our ability to timely complete drilling and development activities, could cause us to incur additional costs in the affected areas and could adversely affect our future production from those areas.

Homeland Security. Legislation continues to be introduced in Congress, and development of regulations continues in the Department of Homeland Security and other agencies, concerning the security of industrial facilities, including oil and natural gas facilities. Our operations may become subject to such laws and regulations. We cannot presently estimate the costs we could incur to comply with any such facility security laws or regulations; however, such expenditures could be substantial.

Federal Energy Regulation. The enactment of the PURPA and the adoption of regulations thereunder by the Federal Energy Regulatory Commission (FERC) provided incentives for the development of cogeneration facilities such as ours. A domestic electricity generating project must be a Qualifying Facility (QF) under FERC regulations in order to benefit from certain rate and regulatory incentives provided by PURPA.

PURPA provides two primary benefits to QFs. First, QFs generally are relieved of compliance with extensive federal regulations, pursuant to the Public Utility Holding Company Act of 1935, as amended, that control the financial structure of an electricity generating plant. Second, FERC's regulations promulgated under PURPA require that electric utilities purchase electricity generated by QFs at a price based on the purchasing utility's avoided cost and that the utility sell back-up power to the QF on a non-discriminatory basis. The term “avoided cost” is defined as the incremental cost to an electric utility of electric energy or capacity, or both, which, but for the purchase from QFs, such utility would generate for itself or purchase from another source. The Energy Policy Act of 2005 amended PURPA to allow a utility to petition FERC to be relieved of its obligation to enter into any new contracts with QFs if FERC determines that a competitive wholesale electricity market is available to QFs in the service territory. Effective November 23, 2011, the California utilities have been relieved of their PURPA obligation to enter into new contracts with cogeneration QFs larger than 20 MW. While the California utilities are still required to enter into new contracts with smaller facilities, such as our Cogen 18 facility, there is no assurance that we will be able to secure new contracts upon the expiration of the existing contracts for our Cogen 38 and Cogen 42 facilities. Even if new contracts are available for our Cogen 38 and Cogen 42 facilities, there is no assurance that the prices and terms of such contracts will not adversely affect our financial condition, results of operations and operating cash flows.

State Energy Regulation. The CPUC has broad authority to regulate both the rates charged by, and the financial activities of, electric utilities operating in California and to promulgate regulation for implementation of PURPA. Since a power sales agreement becomes a part of a utility's cost structure (generally reflected in its retail rates), power sales agreements with independent electricity producers, such as us, are under the regulatory purview of the CPUC and in particular the process by which the utility has entered into the power sales agreements and the prices paid under those agreements. While we are not subject to direct regulation by the CPUC, the CPUC's implementation of PURPA and its authority granted to the IOUs to enter into other PPAs are important to us, as is other regulatory oversight provided by the CPUC to the electricity market in California.

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Other Regulation of the Oil and Natural Gas Industry. The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities, including Native American tribes. Such laws and regulations include requiring permits and bonds for the drilling of wells, reports concerning operations and production, as well as regulations concerning:

- the location of wells, including the distance by which wells must be set back from structures and other activities;
- the method of drilling and casing wells;
- the rates of production or “allowables;”
- surface use and reclamation of property;
- wildlife management and protection;
- the protection of archaeological and paleontological resources;
- property mitigation measures;
- site security;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

In addition, state laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws can establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of natural gas and oil we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil and natural gas within its jurisdiction.

Laws and regulations affecting the oil and natural gas industry are under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, federal, state, local and Native American tribes are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Natural Gas Sales and Transportation. Section 1(b) of the Natural Gas Act (NGA) exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company, but the status of these lines has never been challenged before FERC. The distinction between FERC-regulated transmission services and federally unregulated gathering services is subject to change based on future determinations by FERC, the courts, or Congress, and application of existing FERC policies to individual factual circumstances. Accordingly, the classification and regulation of some of our natural gas gathering facilities may be subject to challenge before FERC or subject to change based on future determinations by FERC, the courts, or Congress. In the event our gathering facilities are reclassified to FERC-regulated transmission services, we may be required to charge lower rates and our revenues could thereby be reduced.

FERC requires certain participants in the natural gas market, including natural gas gatherers and marketers, which engage in a minimum level of natural gas sales or purchases to submit annual reports regarding those transactions to FERC. Should we fail to comply with this requirement or any other applicable FERC-administered statute, rule, regulation or order, we could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation.

Operations on Native American Reservations. A portion of our leases and drill-to-earn arrangements in the Uinta area and some of our future leases in this and other areas may be regulated by Native American tribes. In addition to regulation by various federal, state and local agencies and authorities, an entirely separate and distinct set of laws and regulations applies to lessees, operators and other parties within the boundaries of Native American reservations. Various federal agencies within the U.S. Department of the Interior, particularly the Office of Natural Resources Revenue and the Bureau of Indian Affairs, as well as the EPA, together with each Native American tribe, promulgate and enforce regulations pertaining to oil and natural gas operations on Native American reservations. These regulations include lease provisions, royalty matters, drilling and production requirements, environmental standards, Tribal employment and contractor preferences and numerous other matters.

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Native American tribes are subject to various federal statutes and oversight by the Bureau of Indian Affairs and Bureau of Land Management. However, each Native American tribe is a sovereign nation and has the right to enact and enforce certain other laws and regulations entirely independent from federal, state and local statutes and regulations, as long as they do not supersede or conflict with such federal statutes. These tribal laws and regulations include various fees, taxes, authorizations, requirements to employ Native American tribal members and numerous other conditions that apply to lessees, operators and contractors conducting operations within the boundaries of a Native American reservation. Further, lessees and operators within a Native American reservation are subject to the Native American tribal court system, unless there is a specific waiver of sovereign immunity by the Native American tribe allowing resolution of disputes between the Native American tribe and those lessees or operators to occur in federal or state court.

Therefore, we are subject to various laws and regulations pertaining to Native American tribal surface ownership. In addition, we are subject to the terms and conditions of Native American oil and natural gas leases, as well as fees, taxes, obligations and other issues unique to oil and natural gas ownership and operations within Native American reservations. These laws, regulations and other issues present unique risks that may impose additional requirements on our operations, cause delays in obtaining necessary approvals or permits, or result in losses or cancellations of our oil and natural gas leases, which in turn may materially and adversely affect our operations on Native American tribal lands.

Item 1A. Risk Factors

Oil and natural gas prices are volatile, and declines in prices could materially and adversely affect our business, financial condition, results of operations and operating cash flow. Our future financial condition, revenues, results of operations, rate of growth and the carrying amount of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production and the prices prevailing from time to time for oil and natural gas. Oil and natural gas prices historically have been volatile, and are likely to continue to be volatile in the future, especially given current geopolitical conditions. This price volatility also affects the amount of cash flow we have available for capital expenditures and our ability to borrow money or raise additional capital. The prices for oil and natural gas are subject to a variety of factors beyond our control, including:

- the level of consumer demand for oil and natural gas;
- the domestic and foreign supply of oil and natural gas and the productive capacity of the industry as a whole;
- proximity, availability and capacity of oil and natural gas gathering systems, pipelines, rail cars, other transportation methods and commodity processing and refining facilities;
- the price and level of imports of foreign oil and natural gas;
- developments of the energy infrastructure in the United States, including pipelines and liquefied natural gas facilities;
- the actions of the members of the Organization of Petroleum Exporting Countries and their ability to agree to and maintain oil price and production controls;
- the global and domestic credit, financial and economic environment;
- domestic and foreign governmental regulations and taxes;
- the fluctuation of the United States dollar against other currencies;
- the price and availability of competitors' oil and natural gas supplies in captive markets and of alternative fuel sources;
- weather conditions;
- political and economic conditions, embargoes and political instability, insurgency, terrorism, or war in oil and natural gas producing regions, including the Middle East, Africa and South America, or otherwise affecting other oil and natural gas activities;
- technological advances affecting energy production and consumption;
- variations between product prices at sales points and applicable index prices; and
- acts of force majeure.

These factors and the volatility of oil and natural gas markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. Declines in oil and natural gas prices would reduce our revenues and could also reduce the amount of oil and natural gas that we can produce economically, which could lower our recognized reserve quantities and could materially and adversely affect our financial condition, results of operations and operating cash flows.

Future oil and natural gas price declines may result in write-downs of the carrying amount of our assets, which could materially and adversely affect our results of operations and limit our ability to borrow funds. The value of our assets depends on oil and natural gas prices. Declines in these prices as well as increases in development costs, changes in well performance, delays in asset development or deterioration of drilling results may result in our having to make material

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downward adjustments to our estimated proved reserves, and accounting rules may require us to write down, and incur a corresponding non-cash charge to earnings, the carrying amount of our oil and natural gas properties for impairments.

Proved oil and natural gas properties are reviewed for impairment on a field-by-field basis when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. We estimate the expected future cash flows of our oil and natural gas properties and compare these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures and discount rates commensurate with the risk associated with realizing the projected cash flows. For example, in 2011 we recorded an impairment of $625.0 million related to our E. Texas natural gas assets, largely due to the impact of lower natural gas prices. See Notes 8 and 10 to the Financial Statements. If commodity prices decline in the future, we may incur additional impairment charges, which could materially and adversely affect our financial condition and results of operations.

The borrowing base of our credit facility is subject to semi-annual redeterminations in April and October of each year, based on the value of our oil and natural gas properties, in accordance with the lenders' customary procedures and practices. We and the lenders each have a right to one additional redetermination each year. As of December 31, 2012, the borrowing base under our credit facility was $1.4 billion and total lender commitments were $1.2 billion. Declines in oil or natural gas prices in the future could limit our borrowing base and reduce our ability to borrow under our credit facility. Additionally, divestitures of properties could result in a reduction of our borrowing base.

We require substantial capital expenditures to conduct our operations, engage in acquisition activities and replace our production, and we may be unable to obtain financing on satisfactory terms necessary to execute our operating strategy. The oil and natural gas industry is capital intensive. We require substantial capital expenditures to conduct our production, development and exploration activities, engage in acquisition activities and replace our production. Historically, we have funded our capital expenditures through a combination of our cash flows from operations, borrowings under our credit facility and the capital markets. Our access to capital is subject to a number of factors, some of which are outside our control. These factors include, among others:

- the market value and performance of our debt and equity securities;
- the credit ratings assigned to our debt by independent rating agencies; and
- the global and domestic credit, financial and economic environment.

If our cash flows from operations or the borrowing base under our credit facility decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. Further, our credit facility places certain restrictions on our ability to obtain new financing, and we may not be able to obtain new financing on terms favorable to us, or at all. If cash generated by operations or borrowings under our credit facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our development and exploration activities, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves as well as our financial condition, results of operations and operating cash flows.

The actual quantities and present values of our proved oil and natural gas reserves may be less than we have estimated. It is not possible to measure underground accumulations of oil or natural gas in an exact way. Estimating accumulations of oil and natural gas is a complex process that relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions, such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds, some of which are mandated by the SEC.

Actual future production, oil and natural gas prices, revenues, production taxes, development expenditures, operating expenses and quantities of producible oil and natural gas reserves will most likely vary from those estimated. Any significant variance could materially and adversely affect the estimated quantities of and present values related to our proved reserves, and the actual quantities and present values may be less than we have previously estimated. In addition, we may adjust estimates of proved reserves to reflect production history, results of development and exploration activities, prevailing oil and natural gas prices, costs to develop and operate properties and other factors, many of which are beyond our control. Our properties may also be susceptible to hydrocarbon drainage from production on adjacent properties.

Further, it should not be assumed that any present value of future net cash flows from our estimated proved reserves represents the market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our estimated proved reserves on first-day-of-month average oil and natural gas prices for the twelve-month period preceding the estimate and on costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net revenues will be affected by factors such as the amount and timing of actual development expenditures, the rate and timing of production and changes in governmental regulations or taxes.

Approximately 45% of our total estimated proved reserves at December 31, 2012, were undeveloped, and those reserves may not ultimately be developed. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. Our reserve estimates include the assumption that we will make significant capital expenditures to develop these undeveloped reserves and the actual costs, development schedule and results associated with these properties may not be as estimated. Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, seasonal conditions, access rights and constraints, regulatory approvals, oil and natural gas prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could materially and adversely affect our financial condition, results of operations and operating cash flows.

In addition, the SEC rules generally require that reserves classified as proved undeveloped be capable of conversion into proved developed within five years of classification unless specific circumstances justify a longer time. Proved undeveloped reserves that are not timely developed are subject to possible reclassification as non-proved reserves. These requirements may limit our ability to classify additional reserves as proved undeveloped as we pursue our drilling program. Material downward adjustments to our estimated proved reserves could materially and adversely affect our financial condition, results of operations and operating cash flows.

We depend on successful exploration, development and acquisitions to maintain reserves and revenue in the future. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated. Our future oil and natural gas production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves and efficiently developing and exploiting our current reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would materially and adversely affect our business, financial condition and results of operations and operating cash flows.

Recent regulatory changes in California have and may continue to materially and adversely impact our production and operating costs related to our Diatomite assets. Recent regulatory changes in California have impacted our Diatomite production. In 2010, Diatomite production decreased significantly due to the inability to drill new wells pending the receipt of permits from DOGGR. We received a new full-field development approval in late July 2011 from DOGGR, which contained stringent operating requirements. Revisions to the July 11 project approval letter were received in February 2012. Implementation of these new operating requirements negatively impacted the pace of drilling and steam injection and increased our operating costs for our Diatomite assets. The requirements continued to affect our operations through 2012, and we may not be successful in streamlining the review process with DOGGR or in taking additional steps to more efficiently manage our operations to avoid additional delays. In addition, DOGGR may impose additional operational restrictions or requirements. In such case, we may experience additional delays in production and increased operating costs related to our Diatomite assets, which could materially and adversely affect our business, financial condition and results of operations and operating cash flows.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production. Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. For example, refinery constraints in the Utah region, coupled with our increased production in the area, have impacted the immediate marketability of a portion of our Utah oil, and have caused us to pursue alternate transportation methods and sales outlets. Beginning in 2013, these constraints have caused us to initiate measures to reduce production, such as shutting in some of our wells and postponing completions of some of our newly drilled wells. We may not be successful in securing alternative sales outlets for our Utah production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines, rail transportation and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, processing facilities,

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trucking and rail capability and refineries owned and operated by third parties. We may be required to shut in wells for a lack of a market or because of inadequacy or unavailability of oil and natural gas pipelines, gathering system capacity, storage capacity, processing facilities or refineries. Decreased access to oil and natural gas markets or access to such markets on unacceptable terms could result in increased costs, decreased margins, decreased production, or other factors which could materially and adversely affect our business, financial condition and results of operations and operating cash flows.

We may not be able to deliver minimum crude oil volumes required by our sales contract. Production volumes from our Uinta properties over the next several years are uncertain, and there is no assurance that we will be able to consistently meet the required volume under our refining contract relating to our production from these properties, which is 5,000 Bbl/d. In the event that we cannot produce the necessary volume, we may need to purchase crude to meet our contract requirements. Gross oil production from our Uinta properties subject to the terms of this contract averaged approximately 4,420 Bbl/d during 2012.

The inability of one or more of our customers to meet their obligations may adversely affect our financial results. We have significant concentrations of credit risk with the purchasers of our oil and natural gas. For example, 43% of our oil production is sold to one refiner in California. Due to the terms of supply agreements with our customers, we may not know that a customer is unable to make payment to us until months after production has been delivered. If the purchasers of our oil and natural gas become insolvent, we may be unable to collect amounts owed to us, which could materially and adversely affect our financial condition, results of operations and operating cash flows.

Drilling is a high-risk activity and as a result we may not adhere to our proposed drilling schedule or our drilling program may not result in commercially productive reserves. Our future success will partly depend on the success of our drilling program. Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame, or at all. Our decisions to explore, develop or otherwise exploit prospects or properties will depend on a number of factors, including:

- results of our exploration efforts and the acquisition, review and analysis of our seismic data, if any;
- availability of sufficient capital resources to us and any other participants for the drilling of the prospects;
- approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and natural gas and the availability and prices of drilling rigs and crews;
- availability of leases, license options, farm-outs, other rights to explore and permits on reasonable terms for the prospects; and
- overruns in budgeted expenditures and future costs of drilling and completing wells.

Additionally, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- well integrity issues and surface expressions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- changes in regulations;
- compliance with governmental or landowner requirements;
- disputes with mineral interest or surface owners and access constraints or limitations on surface use on or near our operating areas;
- loss of title or other title related issues;

- availability, capacity, costs and contractual terms with respect to pipelines, rail transportation and facilities to gather, process, compress, transport and market oil and natural gas; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment and/or services, including experienced labor.

Our drilling plans require drilling permits from state, local and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays which jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material and adverse effect on our ability to explore on or develop our properties.

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Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel. The demand for qualified and experienced field personnel to drill wells and conduct field operations such as geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. The availability of drilling rigs can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region. These types of shortages or price increases could restrict our ability to drill planned wells, conduct planned operations, or could otherwise materially and adversely affect our financial condition, results of operations and operating cash flows.

We may be unable to make attractive acquisitions or successfully integrate acquired operations, and any inability to do so may disrupt our business and hinder our ability to grow. Our business strategy has emphasized growth through strategic acquisitions. We may not be able to continue to identify properties for acquisition or we may not be able to make acquisitions on terms that we consider economically acceptable. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from completing, acquisitions. Our strategy of completing acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. If we are unable to achieve strategic acquisitions, our growth may be impaired, thus impacting our financial condition, results of operations, operating cash flows and reserves. In addition, we may have difficulty integrating the operations, systems, management and other personnel and technology of acquired assets or businesses with our own. These difficulties could disrupt our ongoing business, distract our management and employees, increase our expenses and adversely affect our results of operations. In addition, we may incur additional debt or issue additional equity to pay for any future acquisitions, which issuances may be substantial and could significantly affect our risk profile. Significant acquisitions or other transactions could change or alter the character of our operations and business if the character of acquired properties is different from that of our current properties.

Acquisitions are subject to the uncertainties of evaluating recoverable reserves and potential liabilities. Our recent growth is due in part to acquisitions of properties with additional development potential and properties with minimal production at acquisition but significant growth potential, and we expect acquisitions will continue to contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include: recoverable reserves, exploration potential, future oil and natural gas prices, operating costs, production taxes, access rights and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties, which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not allow us to become sufficiently familiar with the properties, and we do not always discover structural, subsurface, environmental and access problems that may exist or arise. Our review prior to signing a definitive purchase agreement may be even more limited.

There may be threatened or contemplated claims against the assets or businesses we acquire related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities, on acquisitions. We may acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties. If material breaches are discovered by us prior to closing, we could require adjustments to the purchase price or, if the claims are significant, we or the seller may have a right to terminate the agreement. If we fail to discover breaches or defects prior to closing, we may incur significant unknown liabilities, including environmental liabilities, for which we would have limited or no contractual remedies or insurance coverage.

We may incur losses as a result of title deficiencies. We acquire working and revenue interests in the oil and natural gas leaseholds and estates upon which we will perform our exploration activities from third parties, or directly from the mineral fee owners. The existence of a material title deficiency can reduce the value or render a property worthless, thus materially and adversely affecting our financial condition, results of operations and operating cash flow. Title insurance covering mineral leaseholds is not always available, and when available is not always obtained. As is customary in our industry, we rely upon the judgment of staff and independent landmen who perform the field work of examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest and/or undertake drilling activities. We, in some cases, perform curative work to correct deficiencies in the marketability of the title to us. In

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cases involving material title problems, the amount paid for affected oil and natural gas leases or estates can be generally lost, and a prospect can become undrillable.

We may incur material losses and be subject to material liability claims as a result of our oil and natural gas operations. In addition, we may not be insured for, or our insurance may be inadequate to protect us against, these risks. Oil and natural gas operations are subject to many risks, including fires, explosions, well blowouts, surface expressions, uncontrollable flows of oil and natural gas, formation water or drilling fluids, adverse weather, freezing conditions in our various regions, natural disasters, pipe or cement failures, casing collapse, embedded oilfield drilling and service tools, formations with abnormal pressures, major equipment failures, including cogeneration facilities, pollution, releases of toxic gas and other environmental risks and hazards. The occurrence of these events could also impact other parties, including residential areas near our operations, our employees and employees of our contractors, leading to injuries, death, environmental damage, property damage, or suspension of operations. As a result, we face the possibility of liabilities from these events that could adversely affect our business, financial condition or results of operations as well as regulatory actions and adverse publicity that could lead to delays in or cessation of our operations in the affected area and loss of related assets or revenues.

Under certain circumstances, we may be liable for environmental damage caused by previous owners or operators of properties that we own, lease, or operate. As a result, we may incur material liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development, or acquisitions, or cause us to incur losses.

We maintain insurance against some, but not all, of these potential risks and losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. We currently have insurance policies covering our operations that include coverage for general liability, excess liability, physical damage to our oil and natural gas properties, operational control of wells, oil pollution, third-party liability, workers' compensation and employers' liability and other coverages. While we intend to obtain and maintain insurance coverage we deem appropriate for these risks, there can be no assurance that our operations will not expose us to liabilities exceeding such insurance coverage or to liabilities not covered by insurance. The occurrence of an event not fully covered by insurance could materially and adversely affect our financial condition, results of operations and operating cash flows.

Our use of hedging transactions could result in financial losses or reduce our earnings. To reduce our exposure to fluctuations in oil and natural gas prices, we have entered into and expect in the future to enter into derivative instruments (or hedging contracts) for a portion of our anticipated oil and natural gas production or natural gas consumption. Our hedging transactions expose us to certain risks and financial losses, including, among others, the risk that we may be limited in receiving the full benefit of increases in oil and natural gas prices as a result of these transactions, and that we may hedge too much or too little production or consumption depending on how oil and natural gas prices fluctuate in the future.

Due to the volatility of oil and natural gas prices, we may be required to recognize unrealized gains and losses (non-cash changes in fair value) on derivative instruments as the estimated fair value of our commodity derivative instruments is subject to significant fluctuations from period to period. The amount of any actual gains or losses recognized will likely differ from our period to period estimates and will be a function of the actual price of the commodities on the settlement date of the derivative instrument. We expect that commodity prices will continue to fluctuate in the future and, as a result, our periodic financial results will continue to be subject to fluctuations related to our derivative instruments.

Our financial counterparties may be unable to satisfy their obligations. We rely on financial institutions to fund their obligations under our credit facility and make payments to us under our commodity hedging contracts. Currently, all of our outstanding commodity derivative instruments are with lenders or affiliates of the lenders under our credit facility. The risk that a counterparty may default on its obligations was heightened by the recent financial crisis, global economic slowdown, European sovereign debt crisis and related losses incurred by many banks and other financial institutions, including some of our counterparties or their affiliates. If one or more of our financial counterparties becomes insolvent, they may not be able to meet their commitment to fund future borrowings under our credit facility which would reduce our liquidity and materially and adversely affect our ability to fund capital expenditures and make acquisitions. If our financial counterparties are unable to make payments under our commodity hedging contracts, our cash receipts from derivative settlements would decrease at a time when we would also be impacted by low commodity prices. As a result, this could materially and adversely affect our financial condition, results of operations and operating cash flows.

A widening of commodity differentials may materially and adversely impact our revenues and our economics. The oil and natural gas we produce is priced in local markets where production occurs and is based on local or regional supply and demand factors as well as other local market dynamics such as regional storage capacity and transportation. The prices that we receive for our oil and natural gas production are generally lower than the relevant benchmark prices, such as NYMEX or

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Brent, that are used for calculating commodity derivative positions. The difference between the benchmark price and the price we receive is called a differential.

We may be unable to accurately predict oil and natural gas differentials, which may widen significantly in the future. Numerous factors may influence local commodity pricing, such as refinery capacity, pipeline takeaway capacity and specifications, localized storage capacity, upsets in the mid-stream or downstream sectors of the industry, trade restrictions and governmental regulations. We may be materially and adversely impacted by a widening differential on the products we sell. Our commodity hedging contracts are typically based on West Texas intermediate (WTI) or other oil or natural gas index prices. As a result, we may be subject to “basis risk” if the differential on products we sell widens from the benchmarks used in our commodity hedging contracts. Additionally, regional capacity and storage issues may cause benchmark prices to become disconnected from regional oil and natural gas prices which may materially and adversely affect our ability to hedge using contracts based on such indices. Insufficient pipeline capacity, storage capacity or trucking or rail transportation capability and the lack of demand in any given operating area may cause the differential to widen in that area compared to other oil and natural gas producing areas. Increases in the differential between benchmark prices for oil and natural gas and the wellhead price we receive could materially and adversely affect our financial condition, results of operation and operating cash flows.

A shortage or increase in the price of natural gas in California could materially and adversely affect our business. The development of our heavy oil in California is subject to our ability to make sufficient quantities of steam at a an economic cost. We may be subject to the risks associated with a shortage of natural gas and/or the transportation of natural gas into and within California. We are highly dependent on sufficient volumes of natural gas necessary to use for fuel in generating steam in our heavy oil operations in California. If the required volume of natural gas for use in our operations were to be unavailable or too highly priced to produce heavy oil economically, our production could be materially and adversely impacted.

We are dependent on our cogeneration facilities and deteriorations in the electricity market and regulatory changes in California may materially and adversely affect our financial condition, results of operations and operating cash flows. We are dependent on three cogeneration facilities that, combined, provide approximately 17% of our steam capacity as of December 31, 2012. These facilities are dependent on viable contracts for the sale of electricity. Market fluctuations in electricity prices and regulatory changes in California could adversely affect the economics of our cogeneration facilities and the corresponding increase in the price of steam could significantly impact our operating costs. If we are unable to enter into new or replacement contracts or were to lose existing contracts, we may be unable to meet our steam requirements necessary to maximize production from our heavy oil assets. An additional investment in various steam sources may be necessary to replace such steam, and there may be risks and delays in being able to install conventional steam equipment due to permitting requirements and availability of equipment. The financial cost and timing of such new investment could materially and adversely affect our financial condition, results of operations and operating cash flows. For a more detailed discussion of our electricity sales contracts, see Part I, Item 1, "Business—Electricity."

Changes to current income tax laws may affect our ability to take certain deductions. Substantive changes to the existing federal income tax laws have been proposed that, if adopted, would affect, among other things, our ability to take certain deductions related to our operations, including depletion deductions, deductions for intangible drilling and development costs and deductions for United States production activities. These changes, if enacted into law, could materially and adversely affect our financial condition, results of operations and operating cash flows.

Recently enacted derivatives legislation could have an adverse impact on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. New comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the

Commodity Futures Trading Commission (CFTC) to regulate certain markets for over-the-counter (OTC) derivative products. In its rulemaking under the new legislation, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalent. Certain bona fide hedging transactions or positions would be exempt from these position limits. The position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. The CFTC appealed the district court's ruling and that appeal is pending. The financial reform legislation may also require our swap-dealer counterparties to comply with margin requirements and/or capital requirements relating to our uncleared swaps with those counterparties, but the timing of any adoption of any such regulations, and their scope, are uncertain. These and other CFTC rules implementing Dodd-Frank could impose burdens on market participants to such an extent that liquidity in the bilateral OTC derivative market decreases substantially. The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations, including determinations with respect to the applicability of margin and capital requirements for uncleared trades, could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize

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or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could limit our ability to plan for and fund capital expenditures. Any of these consequences could materially and adversely affect our financial condition, results of operations and operating cash flows.

Competition within our industry is intense and may materially and adversely affect our operations. We operate in a highly competitive environment. We compete with major and independent oil and natural gas companies in acquiring desirable oil and natural gas properties and in obtaining the equipment and labor required to develop and operate such properties. We also compete with major and independent oil and natural gas companies in the marketing and sale of oil and natural gas. Many of our competitors are larger, fully integrated energy companies that have financial, staff and other resources substantially greater than ours, may be less leveraged than we are and have a lower cost of capital. As a result, our competitors may have greater access to capital and may be able to pay more for development prospects and producing properties, or evaluate and bid for a greater number of properties and prospects than our financial and staffing resources permit. Our competitors may be able to expend greater resources on changing technologies that are increasingly important to efficiency and success in the industry and may also have a greater ability to continue drilling activities during periods of low oil and natural gas prices or to absorb the burden of present and future federal, state, local and other laws and regulations. From time to time, we have to compete with financial investors in the property acquisition market, including private equity sponsors with more funds and access to additional liquidity. Many of these competitors have financial and other resources substantially greater than ours.

In addition, oil and natural gas producers are increasingly facing competition from providers of alternative energy, and government policy may favor those competitors in the future. We can give no assurance that we will be able to compete effectively in the future, which could materially and adversely affect our financial condition, results of operations and operating cash flows.

Our oil and natural gas operations are subject to various environmental and other governmental laws and regulations that may materially affect our operations. Our oil and natural gas operations are subject to extensive U.S. federal, state, local and Tribal laws and regulations. These laws and regulations may be changed in response to economic, political or other conditions. There can be no assurance that present or future regulations will not materially and adversely affect our business and operations. Matters subject to regulation include the following:

- discharge permits for drilling operations;
- reports concerning operations;
- well spacing;
- unitization and pooling of properties; and
- taxation.

Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. See Part I, Item 1, “Business—Environmental Matters and Other Regulations" for additional information on the effect of environmental laws and regulations.

Many of the laws and regulations to which our operations are subject include those relating to the protection of the environment, including those governing the discharge of materials into the water and air, the generation, management and disposal of hazardous substances and wastes and the clean-up of contaminated sites. We may be required to incur material operating costs or significant additional capital expenditures in order to comply with environmental regulations and in connection with obtaining and maintaining construction and operating permits and approvals from state and federal regulatory agencies. The costs related to compliance with environmental regulations could include costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with regulatory reporting requirements. We could also incur material costs, including clean-up costs, fines and civil and criminal sanctions and third-party claims for property damage and personal injury as a result of violations of, or liabilities under, environmental laws and regulations. Such laws and regulations not only expose us to liability for our own activities, but may also expose us to liability for the conduct of others or for actions by us that were in compliance with all applicable laws at the time those actions were taken. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce.

In particular, regulation of GHG emissions by Congress, the EPA, or various other legislative or regulatory bodies in the United States could have an adverse effect on our operations, financial condition, and results of operations and demand for the oil and natural gas we produce. The level of expenditure required to comply with GHG laws and regulations is uncertain and is expected to vary depending on the laws and regulations enacted in each jurisdiction, our activities, and market conditions. The effect of GHG regulations on our financial performance will depend on the sectors covered, GHG emissions reductions required, the extent to which we would receive GHG allowance allocations or the extent to which we would need to purchase compliance instruments in the open market or through auctions, the price and availability of compliance instruments and the impact of GHG laws and regulations on our ability to recover the costs incurred through the pricing of our products. For example, GHG regulations in the state of California will likely increase our operating costs in that state. See "California GHG Regulations" under Part I, Item 1, "Business—Environmental Matters and Other Regulations" for more detail. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition, results of operations and operating cash flows.

In addition, we could incur material expenditures complying with environmental laws and regulations, including future environmental laws and regulations that may be more stringent including, for example, the regulation of GHG emissions under new federal legislation, the federal Clean Air Act, or state or regional regulatory programs. In addition, changes in interpretations of or enforcement of existing laws may cause us to incur substantial expenditures. Operating in densely populated regions may expose us to additional risk of regulation, as well as claims by property owners and others affected by such operations. See Part I, Item 1, "Business—Environmental Matters and Other Regulations" for more detail on both current and potential governmental regulation.

Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and operating restrictions or delays. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. Due to concerns raised relating to potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the Federal level and in some states have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. For example, the EPA has asserted federal regulatory authority over hydraulic fracturing involving fluids that contain diesel fuel under the SDWA's Underground Injection Control Program and has released draft permitting guidance for hydraulic fracturing operations that use diesel fuel in fracturing fluids in those states where the EPA is the permitting authority. In addition, both Texas and Colorado have adopted public disclosure regulations requiring varying degrees of disclosure of the constituents in hydraulic fracturing fluids. The adoption of any future federal or state laws or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to perform hydraulic fracturing, complete oil and natural gas wells in shale formations, and obtain permits, and could increase our costs of compliance and doing business. For a more detailed discussion of hydraulic fracturing matters impacting our business, see Part I, Item 1, "Business—Environmental Matters and Other Regulations."

Our ability to produce oil and natural gas in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of or recycle the water we use at a reasonable cost. The hydraulic fracturing process on which we depend to drill for commercial quantities of oil and natural gas requires the use and disposal of significant quantities of water. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations. Compliance with environmental regulations and permit requirements governing the withdrawal, storage, and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could materially and adversely affect our financial condition, results of operations and operating cash flows.

The loss of key personnel could materially and adversely affect our business. We depend to a large extent on the efforts and continued employment of our executive management team and other key personnel. The loss of the services of these or other key personnel could materially and adversely affect our business, and we do not maintain key man insurance on the lives of any of these persons. Our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract, compensate and retain experienced geologists, engineers, landmen and other professionals. Competition for many of these professionals is intense. If we cannot attract, compensate and retain experienced technical personnel and other professionals, our ability to compete could be harmed.

Interruptions in information technology systems and infrastructure could materially and adversely affect our business. Our business is increasingly dependent on information technology systems to conduct exploration, development and production activities. System failures, network disruptions and breaches of data security could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. In addition, the oil and gas distribution and transportation systems on which we rely to deliver our production to market depend upon information technology systems and infrastructure. Cyber attacks directed at the oil and gas industry could damage distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions. While we have taken steps to address these concerns by implementing network

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security and internal control measures, there can be no assurance that a system failure, network disruption or data security breach will not have a material adverse effect on our business, financial condition, results of operations and operating cash flows. Further, as technology continues to evolve, we may be required to expend significant additional resources to modify or enhance our protective measures or to investigate and remediate any vulnerabilities.

We have a substantial amount of debt and the cost of servicing that debt could adversely affect our business, and such risk could increase if we incur more debt. We have a substantial amount of indebtedness. As of December 31, 2012, we had approximately $1.7 billion of total outstanding long-term debt, including $562.9 million of outstanding borrowings under our credit facility (excluding $23.2 million of outstanding letters of credit). Total lender commitments under the facility are $1.2 billion, and the borrowing base is currently approximately $1.4 billion. Our level of indebtedness relative to our proved reserves and the significant demands on our cash resources could have important effects on our business. Despite current indebtedness levels, we may still be able to incur substantially more debt. The terms of the agreements governing our indebtedness permit us to incur substantial additional indebtedness, which additional indebtedness could:

- make it more difficult for us to satisfy our obligations with respect to our senior notes and our other debt;
- require us to dedicate a substantial portion of our operating cash flows to payments on our debt, thereby reducing the amount of our cash flow available for working capital, capital expenditures, acquisitions and other general corporate purposes;
- require us to make principal payments under our credit facility if the quantity of proved reserves attributable to our natural gas and crude oil properties are insufficient to support our level of borrowings under the credit facility;
- limit our flexibility in planning for, or reacting to, changes in the oil and natural gas industry;
- place us at a competitive disadvantage compared to our competitors that have lower debt service obligations and significantly greater operating and financing flexibility than we do;
- limit our financial flexibility, including our ability to borrow additional funds, pay dividends, make capital expenditures and other investments and acquisitions;
- increase our interest expense if interest rates increase;
- increase our vulnerability to general adverse economic and industry conditions; and
- result in an event of default upon a failure to comply with financial covenants contained in the agreements governing our indebtedness which, if not cured or waived, could have a material adverse effect on our business, financial condition or results of operations.

Our ability to pay the principal and interest on our long-term debt and to satisfy our other liabilities may depend upon our future performance and our ability to refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by economic and capital markets conditions, oil and natural gas prices, our financial condition, results of operations and prospects and other factors, many of which are beyond our control. If we are unable to service our indebtedness and fund our operating costs, we will be forced to adopt alternative strategies that may include reducing or delaying capital expenditures, seeking additional debt financing or equity capital, selling assets or restructuring or refinancing debt. There can be no assurance that any such strategies could be implemented on satisfactory terms, if at all.

Restrictions in our existing and future debt agreements could limit our growth and our ability to respond to changing conditions. Agreements governing our outstanding debt restrict our ability to, among other things:

- incur, assume or guarantee additional indebtedness or issue redeemable stock;
- pay dividends or distributions or redeem or repurchase capital stock;
- prepay, redeem or repurchase debt that is junior in right of payment to our senior and subordinated notes;
- make loans and other types of investments;
- incur liens;
- sell or otherwise dispose of assets;

- consolidate or merge with or into, or sell substantially all of our assets to, another person;
- make capital expenditures or acquire assets or businesses;
- enter into transactions with affiliates; and
- enter into new lines of business.

In addition, our credit facility contains certain covenants, which, among other things, require the maintenance of (i) an interest coverage ratio of 2.75 to 1.0 and (ii) a minimum current ratio of 1.0 to 1.0. Our ability to borrow under our credit facility is dependent upon the quantity of proved reserves attributable to our oil and natural gas properties and the respective projected commodity prices as determined by the lenders under our credit facility. Our ability to meet these covenants or requirements may be affected by events beyond our control, and we cannot assure that we will satisfy such covenants and requirements.

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A downgrade in our credit rating could materially and adversely impact our cost of and ability to access capital. Our access to credit and capital markets also depends on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access capital or financial markets in the future, increase our borrowing costs and potentially require us to post letters of credit for certain obligations.

Risk Factors Related to the Proposed Merger with LinnCo, LLC

Failure to complete or delays in completing the merger could have an adverse impact on our stock price and our business. If the merger is not completed, or there are delays in completing the merger, our stock price and our business could be adversely affected and we would be subject to a number of risks, including the following:

- the current trading price of our common stock may reflect a market assumption that the merger will be completed and a failure to complete or delays in completing the merger could result in a decline in the price of our common stock;
- we may not realize the benefits expected from the merger, including cost savings, enhanced financial and competitive position and diversification of customer base, operating locations and assets;
- we will be required to pay certain costs relating to the merger, including certain investment banking, financing, legal and accounting fees and expenses, whether or not the merger is completed, and we may be required to pay LinnCo a termination fee of up to $83.7 million under certain circumstances; and
- the merger agreement places certain restrictions on the conduct of our business prior to completion of the merger or termination of the merger agreement, and such restrictions prevent us from making certain acquisitions or taking certain other specified actions during the pendency of the merger.

There can be no assurance that these risks will not materialize, and if any of them do, they may have an adverse effect on our financial position, results of operations and operating cash flows.

The merger may cause substantial disruption to our business, cause distraction to our management and employees and present difficulties retaining employees. The merger may cause substantial disruption to our business, cause distraction to our management and employees and present difficulties retaining employees. The merger may also cause uncertainty to our customers. Matters related to the merger may require substantial commitments of time and resources and distract our management and employees from day-to-day operations. These disruptions could have an adverse effect on our financial position, results of operations and cash flows. In addition, uncertainty among our employees may have an adverse effect on our business. This uncertainty may impair our ability to retain or attract personnel until the merger is completed. Employee retention may be particularly challenging, as employees may experience uncertainty about their future roles with the combined company.

The merger agreement restricts our ability to pursue alternatives to the merger. The merger agreement contains provisions that prohibit us from soliciting alternative acquisition proposals or offers for a competing transaction. Further, in certain circumstances, including if the merger agreement is terminated because our board of directors changes its recommendation for the merger, we are required to pay LinnCo a termination fee of up to $83.7 million. This obligation may discourage a third party that has an interest in acquiring all of or a significant part of our business from considering or proposing such acquisition.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information required by Item 2. Properties is included under Part I, Item 1, “Business—Properties.”

Item 3. Legal Proceedings

While we are, from time to time, a party to certain lawsuits in the ordinary course of business, we do not believe any of such existing lawsuits will have a material adverse effect on our operations, financial condition, or operating cash flows. For a description of legal matters see "Legal Matters" in Note 9 to the Financial Statements, which descriptions are incorporated by reference herein.

Item 4. Mine Safety Disclosure.

Not applicable.

Executive Officers

Presented below is information about our executive officers as of December 31, 2012. There are no family relationships between any of the executive officers and members of the Board of Directors.

ROBERT F. HEINEMANN, 59, has been President and Chief Executive Officer since June 2004. Mr. Heinemann was Chairman of the Board and interim President and Chief Executive Officer from April 2004 to June 2004. From December 2003 to March 2004, Mr. Heinemann acted as the director designated to serve as the presiding director at executive sessions of the Board in the absences of the Chairman and as liaison between the independent directors and the CEO. Mr. Heinemann joined the Board in March of 2002. From 2000 until 2002, Mr. Heinemann served as the Senior Vice President and Chief Technology Officer of Halliburton Company and as the Chairman of the Halliburton Technology Advisory Committee. He was previously with Mobil Oil Corporation (Mobil) where he served in a variety of positions for Mobil and its various affiliate companies in the energy and technical fields from 1981 to 1999, with his last responsibilities as Vice President of Mobil Technology Company and General Manager of the Mobil Exploration and Producing Technical Center.

DAVID D. WOLF, 42, has been Executive Vice President and Chief Financial Officer since August 2008. Mr. Wolf was previously employed by JPMorgan from 1995 to 2008 where he served as a Managing Director in JPMorgan's Oil and Gas Group and advised on numerous equity, debt and M&A transactions in the energy industry.

MICHAEL DUGINSKI, 46, has been Executive Vice President and Chief Operating Officer since September 2007. Mr. Duginski served as Executive Vice President of Corporate Development and California from October 2005 to August 2007; he acted as Senior Vice President of Corporate Development from June 2004 through October 2005 and as Vice President of Corporate Development from February 2002 through June 2004. Mr. Duginski, a mechanical engineer, was previously employed by Texaco, Inc. from 1988 to 2002 where his positions included Director of New Business Development, Production Manager and Gas and Power Operations Manager. Mr. Duginski is also an Assistant Secretary.

GEORGE T. CRAWFORD, 52, has been Senior Vice President of California Production since May 2009. Mr. Crawford served as Vice President of California Production from October 2005 until May 2009, Vice President of Production from December 2000 through October 2005 and as Manager of Production from January 1999 to December 2000. Mr. Crawford, a petroleum engineer, previously served as the Production Engineering Supervisor for Atlantic Richfield Corp. from 1989 to 1998, with numerous engineering and operational assignments, including Production Engineering Supervisor, Planning and Evaluation Consultant and Operations Superintendent.

WALTER B. AYERS, 69, has held the position of Vice President of Human Resources since May 2006. Mr. Ayers was previously a private consultant to the energy industry from January 2002 until his employment with the Company. Mr. Ayers served as a Manager of Human Resources for Mobil Oil Corporation from June 1965 until December 2000.

SHAWN M. CANADAY, 37, has held the position of Vice President of Finance and Treasurer since August 2009. Mr. Canaday was Vice President and Controller from June 2008 until July 2009 and was Interim Chief Financial Officer from June 2008 until August 2008. Mr. Canaday served as Controller from February 2007 to July 2009, as Treasurer from December 2004 to February 2007 and as Senior Financial Analyst from November 2003 until December 2004. Mr. Canaday has worked in the oil and natural gas industry since 1998 in various finance functions at Chevron and in public accounting. Mr. Canaday is also an Assistant Secretary.

GEORGE W. CIOTTI, 49, was promoted to Vice President of Rocky Mountain Production effective January 2012. Mr. Ciotti was Vice President, Corporate Development from January 2010 until December 2011. Mr. Ciotti was Manager of Business Development from January 2009 through December 2009 and Senior Financial Analyst from December 2007 until December 2008. Immediately prior to joining Berry, Mr. Ciotti was President and Founder of a consulting company focused on financial and business services. He also had ten years of experience with Texaco in positions such as Assistant Controller and Senior Project Economist.

JOHN R. MATSON, 57, has been Vice President of Texas Production since joining Berry Petroleum Company in July 2011 and was appointed an officer in May 2012. Mr. Matson, a petroleum engineer, previously consulted for E&P companies in the U.S. and internationally. Prior to that he held multiple leadership positions in Halliburton and Mobil Oil Corporation where he began his career.

DAVIS O. O'CONNOR, 58, has been the Vice President, General Counsel and Secretary since October 2010. He previously served as a partner and an associate with the Denver law firm of Holland and Hart LLP since 1979 where he

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practiced in the areas of domestic and international business transactions including mergers, acquisitions, divestitures, joint ventures and related transactions, primarily in the oil and natural gas industry.

JAMIE L. WHEAT, 42, has held the position of Controller since August 2009. Ms. Wheat was the Accounting Manager from August 2008 until August 2009. Prior to joining the Company, Ms. Wheat was a Senior Manager in the assurance practice group of KPMG, where she worked from 2001 to 2008.

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PART II

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

Shares of our Class A Common Stock and Class B Stock are each entitled to one vote and 95% of one vote, respectively. Each share of Class B Stock is entitled to a $0.50 per share preference in the event of liquidation or dissolution. Further, each share of Class B Stock is convertible into one share of Class A Common Stock at the option of the holder.

Our Class A Common Stock is listed on the New York Stock Exchange under the symbol BRY. Our Class B Stock is not publicly traded. The market data and dividends for 2012 and 2011 are shown below:

	2012			2011		
	Price Range		Dividends	Price Range		Dividends
	High	Low	Per Share	High	Low	Per Share
First Quarter	$57.20	$42.55	$.080	$52.32	$42.61	$.075
Second Quarter	49.27	31.93	.080	53.76	44.13	.075
Third Quarter	43.25	35.45	.080	61.17	36.53	.080
Fourth Quarter	42.18	30.21	.080	47.92	30.62	.080
Total Dividends Paid			$.320			$.310

There were 476 holders of record of our Class A Common Stock and one holder of record of our Class B Stock as of February 25, 2013.

Dividends

Our regular annual dividend is currently $0.32, payable quarterly in March, June, September and December.

Since our formation in 1985, we have paid dividends on our Common Stock, including eight consecutive semi-annual periods through September 1989 and 93 consecutive quarters thereafter. We intend to continue the payment of dividends, although future dividend payments will depend upon our level of earnings, operating cash flow, capital commitments, financial covenants and other relevant factors. Dividend payments are limited by covenants in our credit facility to the greater of $35 million or 75% of net earnings for any four quarter period. In addition, the indentures governing our senior notes contain provisions potentially restricting our ability to declare dividends if certain situations arise; provided that, notwithstanding such restrictions, we may declare dividends up to $0.36 per share annually (so long as such distributions are less than $20 million annually) in the event that we are not in default under such indentures and up to $10 million in the event we are in a non-payment default under such indentures.

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights(1)	Weighted average exercise price of outstanding options, warrants and rights(1)	Number of securities remaining available for future issuance
Equity compensation plans approved by security holders	1,387,592	$33.71	599,970
Equity compensation plans not approved by security holders	—	—	—

(1) Excludes 545,914 shares of restricted stock units for which the vesting period has not lapsed. For additional information regarding our equity compensation plans, see Note 6 to the Financial Statements.

Issuer Purchases of Equity Securities

None.

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Performance Graph

This graph shall not be deemed "filed" for purposes of Section 18 of the Securities and Exchange Act of 1934 (the Exchange Act) or otherwise subject to the liabilities of that section, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933 or the Exchange Act, regardless of any general incorporation language in such filing.

Total returns assume $100 invested on December 31, 2007 in shares of Berry Petroleum Company, the Russell 2000, the Standard & Poors 500 Index and a Peer Group, assuming reinvestment of dividends for each measurement period. The information shown is historical and is not necessarily indicative of future performance. The 14 companies which make up the "Previous Peer Group" are as follows: Bill Barrett Corp., Cabot Oil & Gas Corp., Cimarex Energy Co., Comstock Resources Inc., Denbury Resources Inc., Forest Oil Corp., Penn Virginia Corp., Plains Exploration & Production Co., Quicksilver Resources Inc., Sandridge Energy Inc., SM Energy Co., Stone Energy Corp., Swift Energy Co. and Whiting Petroleum Corp. The 15 companies which make up the "Current Peer Group" are as follows: Bill Barrett Corp., Cabot Oil & Gas Corp., Cimarex Energy Co., Denbury Resources Inc., Forest Oil Corp., Laredo Petroleum Holdings, Inc., Newfield Exploration CO., Plains Exploration & Production Co., Quicksilver Resources Inc., Rosetta Resources Inc., Sandridge Energy Inc., SM Energy Co., Stone Energy Corp., Swift Energy Co. and Whiting Petroleum Corp. We determined to remove Penn Virginia Corp. and Comstock Resources Inc. from our peer group due to differences in market capitalization of such companies relative to ours. In addition, we determined to include Laredo Petroleum Holdings, Inc., Newfield Exploration Company and Rosetta Resources, Inc. in our peer group because of similarities in market capitalization, the nature and location of such companies' properties, and the business strategies and structure of such companies.

	12/07	12/08	12/09	12/10	12/11	12/12
Berry Petroleum Company	100.00	17.24	67.91	102.78	99.52	80.11
S&P 500	100.00	63.00	79.68	91.68	93.61	108.60
Russell 2000	100.00	66.22	84.21	106.82	102.36	119.08
Current Peer Group	100.00	39.29	68.90	94.15	81.13	76.05
Previous Peer Group	100.00	43.76	66.19	84.15	76.72	74.06

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Item 6. Selected Financial Data

The following table sets forth certain financial information and is qualified in its entirety by reference to the historical financial statements and notes thereto included in Item 8. Financial Statements and Supplementary Data. The financial information at December 31, 2012 and 2011 and for the years ended December 31, 2012, 2011 and 2010 was derived from our audited financial statements and the accompanying notes to those financial statements included in Item 8. Financial Statements and Supplementary Data in this Annual Report on Form 10-K. The financial information at December 31, 2010, 2009 and 2008 and for the years ended December 31, 2009 and 2008 was derived from audited financial data not included in the report.

	Year Ended December 31,				
(in thousands, except per share, production and per BOE data)	2012	2011	2010	2009	2008
Statements of Operations Data:					
Operating Revenues (continuing operations)	$974,832	$919,558	$676,510	$559,403	$746,632
Net earnings (loss) from continuing operations(1)(2)	171,539	(228,063)	82,524	47,224	120,577
Basic earnings (loss) per share from continuing operations(1)(2)	3.11	(4.21)	1.54	1.03	2.67
Diluted net earnings (loss) per share from continuing operations(1)(2)	$3.09	$(4.21)	$1.52	$1.02	$2.64
Production Data (continuing operations):					
Oil production (MBOE)	10,026	9,041	7,925	7,186	7,441
Natural gas production (MMcf)	19,784	23,907	23,988	20,982	18,323
Operating Data (continuing operations) (per BOE):					
Average sales price(3)	$71.81	$71.59	$53.69	$41.23	$73.64
Average operating costs—oil and natural gas production	20.43	18.22	15.92	14.62	17.99
Production taxes	2.96	2.58	1.93	1.70	2.56
G&A	5.39	4.74	4.43	4.61	5.17
DD&A—oil and natural gas production	$16.95	$16.42	$15.05	$13.10	$11.97
Balance Sheet and Other Data (at period end):					
Total assets	$3,325,402	$2,734,952	$2,838,616	$2,240,135	$2,542,383
Long-term debt	1,665,817	1,380,192	1,108,965	1,008,544	1,131,800
Dividends per share	$0.32	$0.31	$0.30	$0.30	$0.30
Cash Flow Data:					
Cash flow from operations	$501,439	$455,899	$367,237	$212,576	$409,569
Development and exploration of oil and natural gas properties	675,951	527,112	310,139	134,946	397,601
Property acquisitions	$78,313	$158,090	$334,409	$13,497	$667,996

(1) In 2011, we recorded an impairment of $625.0 million related to our E. Texas natural gas assets, largely due to the impact of lower natural gas prices.

(2) Due to the volatility of commodity prices, the estimated fair value of our commodity derivative instruments is subject to fluctuations. As a result, since discontinuing hedge accounting on January 1, 2010, we may recognize in earnings significant unrealized gains and losses (non-cash changes in fair value) on commodity derivative instruments from period to period.

(3) Excludes all effects of derivatives. See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information regarding the effect of derivatives on our average realized price.

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

The following discussion and analysis should be read in conjunction with Item 6. Selected Financial Data and the accompanying financial statements and related notes included elsewhere in this Annual Report on Form 10-K. The following discussion contains forward looking statements that reflect our future plans, estimates, beliefs and expected performance. Our actual results may differ materially because of a number of risks and uncertainties. Some of these risks and uncertainties are detailed in Part I, Item 1A. Risk Factors, and elsewhere in this Annual Report on Form 10-K.

Overview

We are an independent energy company engaged in the production, development, exploitation and acquisition of oil and natural gas. We were incorporated in Delaware in 1985. We have been publicly traded since 1987 and trace our roots in California oil production back to 1909. Since 2002, we have expanded our portfolio of assets through selective acquisitions driven by a consistent focus on properties with proved reserves and significant growth potential through low-risk development. Our principal reserves and producing properties are located in California, Texas (Permian and E. Texas), Utah (Uinta) and Colorado (Piceance).

Our revenue, profitability and future growth rate depend on many factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and natural gas prices have been volatile and may fluctuate widely in the future. The following charts highlight the quarterly average NYMEX price trends for crude oil and natural gas since the first quarter of 2010:

Lower oil and natural gas prices may not only decrease our revenues, but may also reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our oil and natural gas reserves. A substantial or extended decline in oil or natural gas prices may result in impairments of our proved oil and natural gas properties and may materially and adversely affect our future business, financial condition, results of operations, operating cash flows, liquidity or ability to finance planned capital expenditures. Lower oil and natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders and is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Alternatively, higher oil prices may result in significant non-cash fair value losses being incurred on our oil derivatives, which could cause us to experience net losses when prices rise.

Steam costs are a significant variable component of our operating costs and fluctuate based on the amount of steam we inject and the price of natural gas used to generate steam. We benefit from lower natural gas prices as a consumer of natural gas in our California operations. In the Permian, Uinta, E. Texas and Piceance, we benefit from higher natural gas pricing as a producer of natural gas. In addition, production rates, labor and equipment costs, maintenance expenses and production taxes influence our operating costs. Our results of operations may fluctuate from period to period based on such factors.

LinnCo, LLC Merger

On February 20, 2013, the Company, Linn Energy, LLC (Linn), LinnCo, LLC (LinnCo), Linn Acquisition Company, LLC, a direct wholly owned subsidiary of LinnCo (LinnCo Merger Sub), Bacchus HoldCo, Inc., a direct wholly owned subsidiary of the Company (HoldCo), and Bacchus Merger Sub, Inc., a direct wholly owned subsidiary of HoldCo (Bacchus Merger Sub), entered into a definitive Agreement and Plan of Merger (the “Merger Agreement”), pursuant to which LinnCo agreed to acquire

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the Company in an all-stock transaction in which the Company's stockholders would receive 1.25 shares representing limited liability company interests in LinnCo (LinnCo Shares) for each share of the Company's common stock.

The transaction will occur through multiple steps. First, the Company will engage in a holding company merger (the HoldCo Merger) involving HoldCo and Bacchus Merger Sub. In the HoldCo Merger, Bacchus Merger Sub will merge with and into the Company, with the Company surviving as a wholly owned subsidiary of HoldCo, and each issued and outstanding share of the Company's Class A common stock and Class B common stock will convert into the right to receive one equivalent share of Class A common stock and one equivalent share of Class B common stock, respectively, of HoldCo.

Second, promptly after the HoldCo Merger, the Company will be converted into a limited liability company. Third, promptly following such conversion, HoldCo will be merged with and into LinnCo Merger Sub, with LinnCo Merger Sub surviving as the surviving company (the LinnCo Merger). In the LinnCo Merger, each share of Holdco's Class A common stock and each share of Holdco's Class B common stock will be converted into 1.25 LinnCo Shares.

Finally, promptly following the LinnCo Merger, LinnCo will contribute all of the outstanding equity interests in LinnCo Merger Sub (and therefore also its indirect ownership interest in the Company) to Linn (the “Contribution”) in exchange for the issuance to LinnCo (the “Issuance”) of newly issued Linn common units. The number of Linn common units to be issued to LinnCo in the Issuance will be equal to the greater of (i) the aggregate number of LinnCo Shares issued in the LinnCo Merger and (ii) the number of Linn common units required to cause LinnCo to own no less than one-third of all of the outstanding Linn common units following the Contribution. In addition, for three years following the closing, Linn will pay to LinnCo additional cash distributions in the amount of $6 million per year.

The closing of the transactions is subject to customary closing conditions, including approval of the Merger Agreement and the transactions contemplated thereby by the stockholders of the Company and the holders of the shares of LinnCo and Linn, receipt of certain opinions by the parties with respect to the tax-free nature of the transactions, and other customary conditions such as expiration of the waiting period under the Hart-Scott-Rodino Act.

Notable Items - Full Year 2012

- Increased oil production 11% from 2011, offsetting a 17% decrease in natural gas production and increasing oil production to 75% of total production in 2012
- Generated an operating margin of $48.79 per BOE, supported by sales of our California heavy oil at a $8.93 average premium over WTI during 2012[(1)]
- Generated discretionary cash flow of $501.7 million from production of 36,402 BOE/D[(1)]
- Increased cash flow from operations by $45.5 million or 10% from 2011
- Increased oil reserves 10% from 2011, replacing 283% of oil production in 2012
- Increased oil reserves to 74% of total proved reserves
- Acquired approximately 28,000 net acres in or contiguous to our core operating areas in the Uinta
- Drilled 74 Permian wells and increased Permian production to 6,735 BOE/D, a 52% increase over 2011
- Increased production from our NMWSS—New Steam Floods by 73% to 1,827 BOE/D
- Drilled 102 Uinta wells and increased Uinta production to 6,133 BOE/D, an 11% increase over 2011
- Received final US Forest Service approval on our Environmental Impact Study for the Ashley Forest in the Uinta
- Drilled 120 Diatomite wells and increased Diatomite production from an intra-month low of 1,750 BOE/D during March 2012 to 4,090 BOE/D during December 2012; Diatomite production averaged 3,255 BOE/D for full-year 2012
- Issued $600 million aggregate principal amount of our 6.375% senior notes due 2022 (2022 Notes) and used the proceeds to, among other things, redeem part of our 2014 Notes and all of our 2016 Notes

Notable Items - Fourth Quarter 2012

- Increased total production 9% from the third quarter of 2012 to 39,500 BOE/D
- Increased production from the third quarter of 2012 in the Uinta by 26% to 7,500 BOE/D, Permian by 16% to 7,965 BOE/D, NMWSS—New Steam Floods by 11% to 2,130 BOE/D and Diatomite by 10% to 3,855 BOE/D compared to the third quarter of 2012
- Increased oil production to 78% of total production from the third quarter of 2012

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(1) Operating margin and discretionary cash flow are non-GAAP measures and reference should be made to "Reconciliation of Non-GAAP Measures" in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations for further explanation as well as reconciliations to the most directly comparable GAAP measures.

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Results of Operations.

We had net earnings of $171.5 million, or $3.09 per diluted share, for the year ended December 31, 2012. Net earnings included a $26.3 million loss on extinguishment of debt associated with repurchasing all $200 million aggregate principal amount of our 8.25% Senior subordinated notes due 2016 (2016 Notes) and $150 million aggregate principal amount of our 10.25% Senior notes due 2014 (2014 Notes), a gain on derivatives of $22.9 million resulting from non-cash changes in fair values and amortization of accumulated other comprehensive income (AOCL) related to de-designated hedges, an expense of $1.8 million related to principal and interest paid in connection with the settlement of disputed royalty payments, dry hole expense of $9.3 million, a $9.3 million cash settlement related to the early termination of our natural gas derivatives, a gain of $0.9 million related to a retroactive payment adjustment for capacity from one of our electricity customers and a $1.0 million gain associated with the sale of our Nevada Assets, in each case net of income taxes. Net earnings also included a $7.2 million benefit from our research and development tax credit. Net cash provided by operating activities was $501.4 million and capital expenditures, excluding capitalized interest and property acquisitions and divestitures, totaled $676.0 million. We drilled 431 net wells during 2012 and achieved average daily production of 36,402 BOE/D in 2012, an increase of 2% from 2011.

We had net earnings of $38.5 million, or $0.69 per diluted share, for the fourth quarter of 2012. Net earnings included a gain on derivatives of $1.0 million resulting from non-cash changes in fair values and amortization of AOCL related to de-designated hedges, dry hole expense of $8.6 million and a gain of $0.9 million related to a retroactive payment adjustment for capacity from one of our electricity customers, in each case net of income taxes. Net earnings for the fourth quarter also included a $7.2 million benefit from our research and development tax credit. Net cash provided by operating activities was $109.8 million and capital expenditures, excluding capitalized interest and property acquisitions and divestitures, totaled $151.9 million. We drilled 88 net wells during the quarter and achieved average daily production of 39,500 BOE/D, an increase of 9% over the third quarter of 2012, primarily due to increased oil production from the Uinta, the Permian and our California properties.

Operating Data.

The following table sets forth selected operating data for the years ended:

	December 31, 2012	%	December 31, 2011	%	December 31, 2010	%
Heavy oil production (BOE/D)	17,905	49	17,397	49	17,124	52
Light oil production (BOE/D)	9,488	26	7,374	21	4,589	14
Total oil production (BOE/D)	27,393	75	24,771	70	21,713	66
Natural gas production (Mcf/D)	54,054	25	65,498	30	65,720	34
Total (BOE/D)(1)	36,402	100	35,687	100	32,666	100
Oil and natural gas, per BOE:						
Average realized sales price	$ 71.00		$ 66.91		$ 52.14	
Average sales price including cash derivative settlements	$ 72.18		$ 65.68		$ 53.84	
Oil price, per BOE:						
Average WTI price	$ 94.15		$ 95.11		$ 79.59	
Price sensitive royalties(2)	(3.36	)	(3.60	)	(3.06	)
Quality differential and other(3)	(0.67	)	0.84		(8.92	)
Oil derivatives non-cash amortization(4)	(1.09	)	(6.77	)	(2.59	)
Oil revenue per BOE	$ 89.03		$ 85.58		$ 65.02	
Add: Oil derivatives non-cash amortization(4)	1.09		6.77		2.59	
Oil derivatives cash settlements(5)	0.07		(9.72	)	(0.90	)
Average realized oil price per BOE	$ 90.19		$ 82.63		$ 66.71	
Natural gas price, per Mcf:						
Average Henry Hub price per MMBtu	$ 2.79		$ 4.04		$ 4.39	
Conversion to Mcf	0.19		0.28		0.22	
Natural gas derivatives non-cash amortization(4)	0.01		0.01		0.08	
Location, quality differentials and other	(0.18	)	(0.23	)	(0.24	)
Natural gas revenue per Mcf	$ 2.81		$ 4.10		$ 4.45	
Add: Natural gas derivatives non-cash amortization(4)	(0.01	)	(0.01	)	(0.08	)
Natural gas derivative cash settlements(5)	0.22		0.46		0.37	
Average realized natural gas price per Mcf	$ 3.02		$ 4.55		$ 4.74	

(1) Oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of oil.

(2) Our Formax property in S. Midway is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above the 2012 base price of $17.43 per barrel as long as we maintain a minimum steam injection level. We met the steam injection level in 2012 and expect to meet the requirement going forward. The base price escalates at 2% annually and will be $17.78 in 2013.

(3) In California, the per barrel oil posting differential at December 31, 2012 was $11.02, ranged from $2.18 to $11.52 during 2012 and averaged $8.93 during 2012. In Utah, the per barrel oil posting differential at December 31, 2012 was ($15.50), ranged from ($12.49) to ($16.52) during 2012 and averaged ($15.63) during 2012.

(4) Non-cash amortization of AOCL resulting from discontinuing hedge accounting effective January 1, 2010. Recorded in the Statements of Operations under the caption oil and natural gas sales.

(5) Cash settlements on derivatives are recorded in the Statements of Operations under the caption realized and unrealized (gain) loss on derivatives, net.

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The following table sets forth selected operating data for the three months ended:

	December 31, 2012	%	December 31, 2011	%	September 30, 2012	%
Heavy oil production (BOE/D)	19,058	48	17,497	49	18,149	50
Light oil production (BOE/D)	11,591	30	8,166	23	9,344	26
Total oil production (BOE/D)	30,649	78	25,663	72	27,493	76
Natural gas production (Mcf/D)	53,106	22	60,759	28	52,758	24
Total (BOE/D)(1)	39,500	100	35,790	100	36,286	100
Oil and natural gas, per BOE:						
Average realized sales price	$ 70.51		$69.29		$70.22	
Average sales price including cash derivative settlements	$ 72.47		$68.80		$71.45	
Oil price, per BOE:						
Average WTI price	$ 88.23		$94.06		$92.20	
Price sensitive royalties(2)	(2.65	)	(3.63	)	(3.12	)
Quality differential and other(3)	0.79		4.75		(0.68	)
Oil derivatives non-cash amortization(4)	(1.03	)	(6.76	)	(1.10	)
Oil revenue per BOE	$ 85.34		$88.42		$87.30	
Add: Oil derivatives non-cash amortization(4)	1.03		6.76		1.10	
Oil derivative cash settlements(5)	1.57		(8.89	)	0.64	
Average realized oil price per BOE	$ 87.94		$86.29		$89.04	
Natural gas price, per Mcf:						
Average Henry Hub price per MMBtu	$ 3.41		$3.54		$2.80	
Conversion to Mcf	0.24		0.21		0.19	
Natural gas derivatives non-cash amortization(4)	—		—		0.02	
Location, quality differentials and other	(0.14	)	(0.24	)	(0.13	)
Natural gas revenue per Mcf	$ 3.51		$3.51		$2.88	
Add: Natural gas derivatives non-cash amortization(4)	—		—		(0.02	)
Natural gas derivative cash settlements(5)	(0.03	)	0.61		(0.04	)
Average realized natural gas price per Mcf	$ 3.48		$4.12		$2.82	

(1) Oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of oil.

(2) Our Formax property in S. Midway is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above the 2012 base price of $17.43 per barrel as long as we maintain a minimum steam injection level. We met the steam injection level in 2012 and expect to meet the requirement going forward. The base price escalates at 2% annually and will be $17.78 in 2013.

(3) In California, the per barrel oil posting differential at December 31, 2012 was $11.02, ranged from $9.83 to $11.04 during the fourth quarter of 2012 and averaged $10.37 during the fourth quarter of 2012. In Utah, the per barrel oil posting differential at December 31, 2012 was ($15.50), ranged from ($15.00) to ($15.50) during the fourth quarter of 2012 and averaged ($15.24) during the fourth quarter of 2012.

(4) Non-cash amortization of AOCL resulting from discontinuing hedge accounting effective January 1, 2010. Recorded in the Statements of Operations under the caption oil and natural gas sales.

(5) Cash settlements on derivatives are recorded in the Statements of Operations under the caption realized and unrealized (gain) loss on derivatives, net.

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The following table reflects our results of operations for the periods presented:

	Year ended			Three months ended		
(in thousands, except per share data)	December 31, 2012	December 31, 2011	December 31, 2010	December 31, 2012	December 31, 2011	September 30, 2012
Oil sales	$881,688	$772,685	$512,699	$231,766	$207,689	$218,952
Natural gas sales	55,573	98,088	106,909	17,145	19,609	13,964
Oil and natural gas sales	$937,261	$870,773	$619,608	$248,911	$227,298	$232,916
Electricity sales	29,940	34,953	34,740	8,586	10,750	9,514
Natural gas marketing	7,631	13,832	22,162	2,253	2,550	1,939
Gain on sale of assets	1,782	—	—	12	—	170
Settlement on Flying J bankruptcy claim	—	—	21,992	—	—	—
Interest and other income, net	1,985	1,784	3,300	307	390	286
Total revenues and other income	$978,599	$921,342	$701,802	$260,069	$240,988	$244,825
Net earnings (loss)	$171,539	$(228,063)	$82,524	$38,499	$(414,733)	$18,126
Diluted net earnings (loss) per share	$3.09	$(4.21)	$1.52	$0.69	$(7.62)	$0.33

Oil and Natural Gas Sales.

Oil and natural gas sales increased $66.5 million, or 8%, in 2012 compared to 2011. The increase was primarily due to a 6% increase in the average sales price in 2012 compared to 2011, largely as a result of an increase in oil sales volumes as a percentage of total sales volumes. Our oil sales volumes increased 10% in 2012 compared to 2011, while our natural gas sales volumes decreased 17%. The oil volume increase was primarily due to an increase in oil production from all of our oil properties except our legacy SMWSS—Steam Floods properties. In 2012, our oil production increased relative to 2011 as follows: Permian 1,800 BOE/D, or 48%; Uinta 440 BOE/D, or 14%; NMWSS—New Steam Floods 770 BOE/D, or 73%; and Diatomite 100 BOE/D, or 3%. These increases in oil production were partially offset by a decrease in production from our SMWSS—Steam Floods properties due to expected production declines. Additionally, the decrease in natural gas sales volumes was primarily due to expected production declines from our E. Texas and Piceance properties, partially offset by increased natural gas production from our Permian and Uinta properties. In addition to the increase in oil sales volumes, non-cash derivative losses decreased by $50.2 million related to de-designated commodity hedges reclassified from AOCL into oil and natural gas sales.

Oil and natural gas sales increased $251.2 million, or 41%, in 2011 compared to 2010. The increase was primarily due to a 28% increase in the average realized sales price and a 10% increase in sales volumes in 2011 compared to 2010. The increase in the average sales price was primarily due to a 19% increase in the average WTI price in 2011 compared to 2010. The increase in oil production as a percentage of total production from 2010 to 2011 also contributed to the increase in the average sales price over that time period. The increase in sales volume was primarily due to a 14% increase in oil sales volume in 2011 compared to 2010, largely due to increased oil production from the Permian, which increased 2,660 BOE/D, or 245%, from 2010 to 2011. Also increasing over the same period was Diatomite oil production, which increased 430 BOE/D, or 16%; NMWSS—New Steam Floods oil production, which increased 250 BOE/D, or 31%; and Uinta oil production, which increased 190 BOE/D, or 6%. These increases were offset by an increase in non-cash derivative losses of $42.5 million related to de-designated commodity hedges reclassified from AOCL into oil and natural gas sales.

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Electricity Sales.

The following table sets forth selected results of operations for the periods ended:

	Year Ended December 31,		
	2012	2011	2010
Electricity			
Electricity sales (in thousands)	$29,940	$34,953	$34,740
Operating costs (in thousands)	$19,975	$25,690	$31,295
Electric power produced (MWh/D)	2,097	1,968	2,088
Electric power sold (MWh/D)	1,918	1,806	1,925
Average sales price per MWh	$40.79	$47.00	$50.06
Fuel gas cost per MMBtu (including transportation)	$2.89	$4.20	$4.49
Estimated natural gas volumes consumed to produce electricity (MMBtu/D)(1)	15,415	15,229	18,171

Electricity sales in 2012 decreased 14% compared to 2011. In 2012 and 2011, electricity sales included retroactive payment adjustments for capacity of $1.3 million and $4.1 million, respectively, from our electricity customers. As a result of our previously disclosed global settlement with various parties that became effective on November 23, 2011, we received retroactive payments for firm capacity that had been originally paid at "as available" capacity rates, and these payments represent the difference in rates over the disputed period. Excluding the retroactive payment adjustments, electricity sales in 2012 would have decreased 7% compared to 2011. The decrease in electricity sales was primarily due to a 13% decrease in the average sales price of electricity, partially offset by a 6% increase in electric power sold period over period primarily due to a decrease in the downtime of our cogeneration facilities in 2012 compared to 2011. Electricity operating costs in 2012 decreased 22% compared to 2011 primarily due to a 31% decrease in fuel gas cost, partially offset by a 1% increase in fuel gas volumes purchased.

Electricity sales increased 1% in 2011 compared to 2010 primarily due to the retroactive capacity refund of $4.1 million received in December 2011 from one of our electricity customers. This increase was offset by a 6% decrease in the average sales price of electricity and a 6% decrease in electric power sold associated with an increase in cogeneration unit downtime in 2011. Electricity operating costs decreased 18% in 2011 compared to 2010 primarily due to a 6% decrease in fuel gas cost and a 6% decrease in electric power produced related to increased cogeneration unit downtime in 2011.

Natural Gas Marketing.

We have long-term firm transportation contracts on the Rockies Express, Wyoming Interstate Company and Ruby pipelines, each with a total average capacity of 35,000 MMBtu/D. Demand charges for our capacity are reflected in operating costs—oil and natural gas production in our Statements of Operations. Our current production is insufficient to fully utilize this capacity. To optimize our remaining capacity, we purchase third-party natural gas at the market rate in our producing areas and utilize FERC-approved asset management agreements. Sales and purchases of third-party natural gas are recorded under natural gas marketing in the revenues and expenses sections of the Statements of Operations, respectively.

The pre-tax net of our natural gas marketing revenue and our natural gas marketing expense for the years ended December 31, 2012, 2011 and 2010 was $0.8 million, $0.8 million and $2.3 million, respectively.

Settlement of Flying J Bankruptcy.

On July 6, 2010, the Joint Plan of Reorganization of Flying J, Inc., Big West of California, LLC, Big West Oil, LLC, Big West Transportation, LLC and Longhorn Partners Pipeline, L.P. was confirmed under Chapter 11 of the United States Bankruptcy Code. Additionally, the United States Bankruptcy Court approved and confirmed the June 15, 2010 Stipulation and Agreed Order (the Stipulation) with Flying J, Inc. and certain of its affiliates (collectively Flying J), regarding the resolution of our claim in Flying J's pending bankruptcy. Pursuant to the Stipulation, we and Flying J agreed that the total amount owed to us by Flying J for the purchases of our California production and other damages was $60.5 million and, as a result, we received $60.5 million in cash on July 23, 2010.

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Gain on Sale of Assets.

In 2012, we recorded a $1.6 million gain in conjunction with the sale of assets related to our Nevada Assets. The gain was recorded in the Statements of Operations under the caption gain on sale of assets. In addition, all three of our drilling rigs were sold in the third quarter of 2012 for $1.8 million, which, less costs to sell of $0.2 million, resulted in a gain of $0.2 million.

Oil and Natural Gas Operating and Other Expenses.

The following table presents information about our oil and natural gas operating and other expenses for each of the years ended December 31:

	Amount per BOE			Amount (in thousands)		
	2012	2011	2010	2012	2011	2010
Operating costs—oil and natural gas production (1)	$20.43	$18.22	$15.92	$272,180	$237,296	$189,809
Production taxes	2.96	2.58	1.93	39,374	33,617	22,999
DD&A—oil and natural gas production	16.95	16.42	15.05	225,892	213,859	179,432
G&A	5.39	4.74	4.43	71,766	61,727	52,846
Interest	6.24	5.59	5.58	83,136	72,807	66,541
Total	$51.97	$47.55	$42.91	$692,348	$619,306	$511,627

(1) Operating costs—oil and natural gas production includes firm transportation costs of $28.6 million, $21.4 million and $16.2 million for the years ended December 31, 2012, 2011 and 2010, respectively.

- Operating costs—oil and natural gas production in 2012 were $272.2 million, or $20.43 per BOE, compared to $237.3 million, or $18.22 per BOE, in 2011. The increase was primarily due to a higher level of workover activity in the Permian and increased transportation costs due to the commencement of Ruby Pipeline operations in July 2011. The shift in production from our natural gas properties, which have lower operating costs, to our oil properties, which have higher operating costs, also contributed to the increase in operating costs from 2011 to 2012. Also increasing over the same time period were contract services, contract labor, chemicals, electricity, well maintenance costs and internal labor costs associated with net wells added during the last 12 months. These increases were partially offset by a $1.7 million decrease in steam costs, primarily due to a decrease in the price of natural gas used in steam generation and a decrease in compression, gathering, and dehydration costs due to the natural decline in production from our natural gas properties.

Operating costs—oil and natural gas production in 2011 were $237.3 million, or $18.22 per BOE, compared to $189.8 million, or $15.92 per BOE, in 2010. The increase primarily results from higher steam costs resulting from higher volumes of injected steam, partially offset by a decrease in the price of natural gas used in steam generation and increases in water hauling and disposal costs, well maintenance and workover costs, contract labor costs and transportation costs.

The following table presents steam information:

	Year Ended December 31,		
	2012	2011	2010
Average net volume of steam injected (Bbl/D)	169,605	132,083	115,651
Fuel gas cost/MMBtu (including transportation)	$2.89	$4.20	$4.49

Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	54,540	44,235	36,020

- Production taxes in 2012 were $39.4 million, or $2.96 per BOE, compared to $33.6 million, or $2.58 per BOE, in 2011. The increase in production taxes was primarily due to an increase in the assessed ad valorem values attributed to our California and Permian properties and an increase in severance taxes, largely due to new wells drilled and increased production, primarily in the Permian, offset by certain tax exemptions in Utah and E. Texas.

Production taxes in 2011 were $33.6 million, or $2.58 per BOE, compared to $23.0 million, or $1.93 per BOE, in 2010. The increase in production taxes was primarily due to an increase in the assessed ad valorem values attributed to our

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California properties and an increase in the number of wells outside California, where property taxes are based largely on assessed value per well. Additionally, our severance taxes increased in 2011, largely due to increased commodity prices.

- DD&A—oil and natural gas production in 2012 was $225.9 million, or $16.95 per BOE, compared to $213.9 million, or $16.42 per BOE, in 2011. On a BOE basis, the rate was 3% higher in 2012 compared to 2011, which contributed to a $6.9 million increase in DD&A—oil and natural gas production. The increase in the DD&A rate was largely due to capitalized costs associated with the development of our properties, partially offset by reserve additions. This increase was partially offset by the impairment of our E. Texas natural gas assets in the fourth quarter of 2011. The 2% increase in production from 2011 to 2012 also contributed to a $5.1 million increase in DD&A—oil and natural gas production.

DD&A—oil and natural gas production in 2011 was $213.9 million, or $16.42 per BOE, compared to $179.4 million, or $15.05 per BOE, in 2010. The increase in DD&A—oil and natural gas production per BOE was primarily due to an overall shift in production volumes to our assets outside of California, which have higher drilling and leasehold acquisition costs than our California properties. In 2011, 49% of our production volumes were heavy oil produced in California, compared to 52% of our production volumes in 2010.

- General and administrative expense (G&A) in 2012 was $71.8 million, or $5.39 per BOE, compared to $61.7 million, or $4.74 per BOE, in 2010. The increase in G&A period over period was primarily due to a $7.1 million increase in employee compensation and benefits resulting from new personnel hired and general pay increases and a $2.0 million increase in consulting costs. These increases are directly attributable to our growing capital program and oil production levels. As of December 31, 2012, we had 374 full-time employees compared to 317 full-time employees as of December 31, 2011. Employee travel costs also increased over the same time period.

G&A in 2011 was $61.7 million, or $4.74 per BOE, compared to $52.8 million, or $4.43 per BOE, in 2010. The increase was due in part to higher employee salary and benefit costs. As of December 31, 2011, we had 317 full-time employees compared to 270 as of December 31, 2010. The increase in employees was primarily due to our acquisitions in the Permian and additional personnel required for our growing capital program and production levels. Additionally, G&A increased due to higher consulting costs directly attributable to our efforts to comply with new regulations in California, as well as our growing capital program and production levels.

- The following table sets forth components of interest expense for the periods presented:

	Year Ended December 31,		
(in thousands)	2012	2011	2010
Senior subordinated notes	$4,492	$16,500	$16,500
Senior notes	76,137	63,288	49,500
Credit facility	9,679	8,314	6,263
Amortization of debt issuance costs and net discount	10,081	11,163	12,296
Amortization of AOCL	(1,785)	871	8,335
Other	2,447	1,788	1,968
Capitalized interest	(17,915)	(29,117)	(28,321)
	$83,136	$72,807	$66,541

Interest in 2012 was $83.1 million, or $6.24 per BOE, compared to $72.8 million, or $5.59 per BOE, in 2011. The increase in interest was primarily a result of the issuance of our 6.375% senior notes due 2022 (2022 Notes) in March 2012, as well as a decrease in capitalized interest and an increase in the average amount of borrowings under our credit facility from 2011 to 2012. These increases were partially offset by a decrease in interest payments related to the repurchase of $150 million aggregate principal amount of our 10.25% Senior notes due 2014 (2014 Notes), a decrease in interest payments related to the redemption of our 8.25% Senior subordinated notes due 2016 (2016 Notes), a decrease in non-cash derivative losses of $2.7 million related to de-designated interest rate hedges reclassified from AOCL into interest expense and a decrease in amortized debt issuance costs and net discount related to the redemption of our 2016 Notes and the partial repurchase of our 2014 Notes.

Interest in 2011 was $72.8 million, or $5.59 per BOE, compared to $66.5 million, or $5.58 per BOE, in 2010. The increase in interest was a result the issuance of our 6.75% senior notes due 2020 (2020 Notes) in November 2010 and an increase in the average amount of borrowings outstanding under our credit facility. These increases were partially offset by a $7.5 million decrease in non-cash derivative losses related to de-designated interest rate hedges reclassified from AOCL into interest expense and a decrease in interest payments related to the repurchase of $94.7 million aggregate principal amount of our 2014 Notes in September and October of 2011.

Dry Hole, Abandonment, Impairment and Exploration. We recorded dry hole, abandonment and impairment charges of $19.0 million, $5.2 million and $1.5 million in 2012, 2011 and 2010, respectively. In 2012, we recorded dry hole expense of $11.9 million related to our four appraisal wells in Borden county whose results were inconclusive for commercial quantities of oil and $2.8 million related to mechanical failure on one well near Lake Canyon, which was abandoned in favor of drilling a nearby replacement well. We also recorded approximately $4.1 million in 2012 related to plugging and abandonment activities in California. In 2011, we recorded a $4.3 million impairment charge related to the write-down of three drilling rigs to their fair value. These rigs were sold in the third quarter of 2012. In 2010, we recorded dry hole expense due to a mechanical failure encountered on one well in the Piceance. See Notes 8 and 10 to the Financial Statements.

We incurred exploration costs in 2012, 2011 and 2010, of $1.9 million, $0.3 million and $1.2 million, respectively. These costs consist primarily of geological and geophysical costs. The exploration costs in 2012 related largely to the purchase of seismic data.

Impairment of Oil and Natural Gas Properties. We recorded non-cash impairments of oil and natural gas properties of $0.1 million, $625.6 million and $0.0 million, in 2012, 2011 and 2010, respectively.

In the fourth quarter of 2011, we recorded a non-cash impairment of $625.0 million related our E. Texas natural gas properties. The impairment was due to decreases in natural gas prices and, as a result, changes in our development plans. In the fourth quarter of 2011, the NYMEX HH five-year future strip (the average of the settlement prices of the next 60 months' futures contracts) decreased approximately 15%. The assets were written down to their estimated fair value. Further, in 2012, 2011 and 2010, we recorded non-cash impairments of $0.1 million, $0.6 million and $0 million, respectively, related to the expiration of acreage, primarily in the Uinta. See Notes 8 and 10 to the Financial Statements.

Extinguishment of Debt. We recorded debt extinguishment costs of $41.5 million, $15.5 million and $0.6 million in 2012, 2011 and 2010, respectively. In 2012, we recorded debt extinguishment costs of $30.9 million in conjunction with the repurchase of $150.0 million aggregate principal amount of our 2014 Notes, consisting of $26.4 million in premiums paid over par and $4.5 million related to net discount and debt issuance costs. We also recorded debt extinguishment costs of $10.6 million in conjunction with the repurchase of all $200.0 million of our 2016 Notes, consisting of $8.3 million in premiums paid over par and $2.3 million related to debt issuance costs. In 2011, we recorded debt extinguishment costs of $15.0 million in conjunction with the repurchase of $94.7 million aggregate principal amount of our 2014 Notes, consisting of $11.5 million in premium paid over par and $3.5 million related to net discount and deferred financing costs. We also recorded debt extinguishment costs of $0.5 million associated with one lender that did not renew its commitment under our credit facility in October 2011. In 2010, we recorded debt extinguishment costs of $0.6 million associated with borrowing base changes under our credit facility.

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Realized and Unrealized (Gain) Loss on Derivatives, Net. The following table sets forth the components of realized and unrealized (gain) loss on derivatives, net, for the periods presented. See Notes 7 and 8 to the Financial Statements.

	Year Ended December 31,		
(in thousands)	2012	2011	2010
Cash (receipts) payments:			
Commodity derivatives—oil	$(671)	$87,747	$7,078
Commodity derivatives—natural gas(1)	(18,915)	(10,806)	(8,889)
Financial derivatives—interest(2)	—	—	17,499
Total realized (gain) loss	$(19,586)	$76,941	$15,688
Non-cash fair value (gain) loss:			
Commodity derivatives—oil	$(61,125)	$(89,478)	$37,440
Commodity derivatives—natural gas(1)	16,091	(1,371)	(12,424)
Financial derivatives—interest(2)	—	—	(8,857)
Total unrealized (gain) loss	$(45,034)	$(90,849)	$16,159
Realized and unrealized (gain) loss on derivatives, net	$(64,620)	$(13,908)	$31,847

(1) In March 2012, we terminated certain of our natural gas derivative instruments, which were associated with a total of 15,000 MMBtu/D for the remainder of 2012. The termination resulted in cash settlements of $14.7 million, offset by a non-cash fair value loss of $16.6 million.

(2) In the fourth quarter of 2010, we terminated certain interest rate derivative instruments for which we had previously elected hedge accounting. The termination resulted in a cash settlement of $10.8 million, offset by a fair value gain of $8.9 million.

Our open commodity derivative contracts at December 31, 2012 were in a net fair value asset position largely because the futures curve of forecasted commodity prices (forward price curve) at December 31, 2012 was generally lower than the forward price curves that were in effect when we entered into the majority of those contracts. Our open commodity derivative contracts at December 31, 2011 were in a net fair value liability position largely because the forward price curve at December 31, 2011 generally exceeded the forward price curves that were in effect when we entered into the majority of those contracts. The change in fair value from a liability position at December 31, 2011 to an asset position at December 31, 2012 resulted in a $45.0 million unrealized gain in 2012. Our open commodity derivative contracts at December 31, 2010 were in a net fair value liability position largely because the forward price curve at December 31, 2011 generally exceeded the forward price curves that were in effect when we entered into the majority of those contracts. The decrease in liability position from December 31, 2010 to December 31, 2011 resulted in a $90.8 million gain in 2011.

Gain on Purchase. In 2011, we recorded a $1.0 million gain (net of deferred income taxes of $0.7 million) in conjunction with usual and customary post-closing adjustments to the purchase price of a November 2010 acquisition in the Permian. The gain was recorded in the Statements of Operations under the caption gain on purchase.

Transaction Costs on Acquisitions. In 2010, we incurred $2.6 million of acquisition related expenses for the acquisition of certain properties in the Permian. See Note 2 to the Financial Statements.

Bad Debt (Recovery) Expense. On July 6, 2010, the Joint Plan of Reorganization of Flying J was confirmed under Chapter 11 of the United States Bankruptcy Code. Additionally, the United States Bankruptcy Court approved and confirmed the Stipulation, pursuant to which Flying J agreed that the total amount owed to us by Flying J was $60.5 million and, as a result, we received $60.5 million in cash on July 23, 2010. In 2010, we recorded a settlement of our Flying J bankruptcy claim of $22.0 million and a bad debt recovery of $38.5 million.

Income Tax (Benefit) Expense. Our effective income tax rates for the years ended December 31, 2012, 2011 and 2010 were 34%, 38% and 40%, respectively. In 2012, the effective income tax rate was reduced by a benefit recorded for research and development tax credits. In 2011, we recorded an income tax benefit due to a pre-tax loss resulting from the impairment of our E. Texas natural gas properties. Our estimated annual effective income tax rate varies from the 35% federal statutory rate primarily due to the effects of state income taxes, domestic production activities deduction, percentage depletion, nondeductible employee compensation, research and development credits and other permanent differences. See Note 4 to the Financial Statements.

As part of the American Taxpayer Relief Act of 2012, passed on January 2, 2013, the Section 41 research and development tax credit was retroactively extended for the 2012 tax year. As a result, it is possible that we will record a benefit related to the 2012 tax year in 2013.

Financial Condition, Liquidity and Capital Resources.

Our development, exploitation and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operations and borrowings under our credit facility as our primary sources of liquidity. The debt and equity capital markets have served as our primary source of financing to fund large acquisitions and other transactions. Our ability to access the debt and equity capital markets on economical terms is affected by general economic conditions, the financial markets, the credit ratings assigned to our debt by independent credit rating agencies, our operational and financial performance, the value and performance of equity and debt securities, prevailing commodity prices and other macroeconomic factors outside of our control. We have also engaged in asset monetization transactions as a source of financing, as market conditions have permitted. As we pursue profitable reserves and production growth, we continually monitor the capital resources, including the issuance of equity and debt securities, available to us to meet our future financial obligations, planned capital expenditure activity and liquidity.

At December 31, 2012, we had a working capital deficit of approximately $129.6 million. We generally maintain a working capital deficit because we use excess cash to reduce outstanding borrowings under our credit facility. Our working capital fluctuates for various reasons, including changes in the fair value of our commodity derivative instruments.

Changes in the market prices for oil and natural gas directly impact our level of cash flow generated from operations. We employ derivative instruments in our risk management strategy in an attempt to minimize the adverse effects of wide fluctuations in the commodity prices on our cash flows. As of December 31, 2012, we had hedged approximately 60% and 20% of our expected oil production in 2013 and 2014, respectively. This level of derivatives is expected to provide a measure of certainty of the cash flows that we will receive for a portion of our production in 2013 and 2014. In the future, we may increase or decrease our derivative positions. At December 31, 2012, all of our derivatives counterparties were commercial banks that are parties, or affiliates of parties, to our credit facility. See Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" and Notes 7 and 8 to the Financial Statements for further details about our derivative positions.

Tender Offer and Redemption of Notes. On April 3, 2012, we repurchased $150.0 million aggregate principal amount of our 2014 Notes for an aggregate purchase price of $181.5 million, including accrued and unpaid interest. The 2014 Notes were repurchased using net proceeds from the issuance of $600 million aggregate principal amount of our 6.375% Senior notes due 2022 (2022 Notes).

On April 9, 2012, we redeemed all $200 million aggregate principal amount of our 2016 Notes for an aggregate purchase price of $215.5 million, including accrued and unpaid interest. The 2016 Notes were redeemed using net proceeds from the issuance of our 2022 Notes.

Senior Secured Revolving Credit Facility. On April 13, 2012, as part of the semi-annual borrowing base redetermination process, we entered into a fourth amendment to our credit facility. Among other things, the fourth amendment increased the borrowing base to $1.4 billion. Total lender commitments remained unchanged at $1.2 billion.

Borrowings under our credit facility bear interest at either (i) LIBOR plus a margin between 1.50% and 2.50% or (ii) the prime rate plus a margin between 0.50% and 1.50%, in each case, based on the amount utilized. The annual commitment fee on the unused portion of the credit facility ranges between 0.35% to 0.50% based on the amount utilized.

As of December 31, 2012, outstanding borrowings under the facility were $562.9 million and $23.2 million in outstanding letters of credit, leaving $613.9 million in borrowing capacity available under the credit facility. The maximum amount available under the credit facility is subject to semi-annual redeterminations of the borrowing base in April and October of each year, based on the value of our proved oil and natural gas reserves, in accordance with the lenders' customary procedures and practices. We and the lenders each have a right to one additional redetermination each year. The semi-annual redetermination in October 2012 did not result in any changes to the borrowing base, lender commitments, or other terms of the credit facility.

The credit facility contains certain covenants, which, among other things, require the maintenance of (i) an interest coverage ratio of at least 2.75 to 1.0 and (ii) a minimum current ratio of 1.0 to 1.0. The credit facility also contains other customary covenants, subject to certain agreed exceptions, including covenants restricting our ability to, among other things, owe or be liable for indebtedness; create, assume or permit to exist liens; be a party to or be liable on any hedging contract; engage in mergers or consolidations; transfer, lease, exchange, alienate or dispose of our material assets or properties; declare dividends on or redeem or repurchase our capital stock; make any acquisitions of, capital contributions to or other investments in any entity or property; extend credit or make advances or loans; engage in transactions with affiliates; and enter into, create or allow to exist contractual obligations limiting our ability to grant liens on our assets to the lenders under the credit facility. As of December 31, 2012, we were in compliance with all financial covenants and have complied with all financial covenants for all prior periods presented.

Subject to certain agreed limitations, we granted first priority security interests over substantially all of our assets in favor of the lenders under the credit facility.

Senior Notes. On March 9, 2012, we issued $600 million aggregate principal amount of our 2022 Notes for net proceeds of $589.5 million. As of December 31, 2012, we had the following senior notes outstanding:

- $205.3 million aggregate principal amount of our 2014 Notes;

- $300.0 million aggregate principal amount of our 2020 Notes; and

- $600.0 million aggregate principal amount of our 2022 Notes.

Our senior notes are senior unsecured obligations, which rank effectively junior to all of our existing and any future secured debt, to the extent of the value of the collateral securing that debt, rank equally in right of payment with other senior unsecured debt, and senior in right of payment to any future subordinated debt. Interest on our senior notes is payable in arrears semi-annually.

The indentures governing our senior notes contain provisions that limit our ability to incur, assume or guarantee additional indebtedness; issue redeemable stock and preferred stock; pay dividends or distributions or redeem or repurchase capital stock; prepay, redeem or repurchase debt that is junior in right of payment to our senior and subordinated notes; make loans and other types of investments; incur liens; restrict dividends, loans or asset transfers from our subsidiaries; sell or otherwise dispose of assets, including capital stock of subsidiaries; consolidate or merge with or into, or sell substantially all of our assets to, another person; enter into transactions with affiliates; and enter into new lines of business. Upon specified change in control events, we will be required to make offers to repurchase our senior notes at amounts specified in the indentures governing such notes.

We may from time to time seek to repurchase our outstanding notes, through open market purchases, privately negotiated transactions or otherwise. Such repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts repurchased may be material.

Credit Ratings. Our credit risk is evaluated by two independent rating agencies based on publicly available information and information obtained during our ongoing discussions with the rating agencies. Moody's Investor Services and Standard & Poor's Rating Services currently rate our outstanding notes and have assigned us a credit rating. We do not have any provisions that are linked to our credit ratings, nor do we have any credit rating triggers that would accelerate the maturity of amounts due under our currently outstanding debt. However, our ability to raise funds and the costs of any financing activities will be affected by our credit rating at the time any such financing activities are conducted.

Historical Cash Flows.

Year Ended December 31,

(in thousands)	2012	2011	2010
Net cash provided by operating activities	$ 501,439	$ 455,899	$ 367,237
Net cash used in investing activities	(758,172)	(711,019)	(672,869)
Net cash provided by financing activities	256,747	255,140	300,599
Net increase (decrease) in cash and cash equivalents	$ 14	$ 20	$ (5,033)

Operating Activities. Cash flows provided by operating activities are primarily affected by the price of oil and natural gas, sales volumes and changes in working capital. The increase in net cash provided by operating activities of $45.5 million in 2012 compared to 2011 was primarily due to a 6% increase in our average realized sales price, largely as a result

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of an increase in oil sales volumes as a percentage of total sales volumes in 2012 compared to 2011. The increase in net cash provided by operating activities of $88.7 million in 2011 compared to 2010 was primarily due to a 28% increase in average commodity sales prices and a 10% increase in sales volume.

Investing Activities. Cash flows used by investing activities are primarily comprised of development, exploitation and acquisition of oil and natural gas properties net of dispositions of oil and natural gas properties. The increase in net cash used in investing activities of $47.2 million in 2012 compared to 2011 was due to an increase in development activities, partially offset by decreases in acquisition activities and capitalized interest, as well as proceeds from the sale of our Nevada Assets. The increase in net cash used in investing activities of $38.2 million in 2011 compared to 2010 was due to an increase in development activities offset by a decrease in expenditures for property acquisitions in 2011 as compared with 2010.

Financing Activities. Net cash provided by financing activities in 2012 included net proceeds of $589.5 million from the issuance of $600 million aggregate principal amount of our 2022 Notes and net borrowings of $31.4 million of borrowings under our credit facility, partially offset by the repurchase of $150 million aggregate principal amount of our 2014 Notes and the repurchase of all $200 million aggregate principal amount of our 2016 Notes. Net cash provided by financing activities in 2011 included net borrowings under our credit facility of $361.5 million, partially offset by the repurchase of $94.7 million aggregate principal amount of our 2014 Notes. Net cash provided by financing activities in 2010 included net proceeds of $224.0 million from the issuance of 8 million shares of our Class A Common Stock and $300.0 million aggregate principal amount of our 2020 Notes, partially offset by debt issuance costs of $15.2 million and net repayment of our outstanding borrowings under our credit facility and our money market line of credit of $196.7 million.

Capital Expenditures.

The following is a summary of the drilling and development capital expenditures:

(in thousands)	Year Ended December 31,		
Asset Team	2012	2011	2010
SMWSS—Steam Floods	$51,000	$47,000	$45,000
NMWSS—Diatomite	85,000	105,000	42,000
NMWSS—New Steam Floods	104,000	51,000	15,000
Permian	272,000	218,000	42,000
Uinta	155,000	63,000	50,000
E. Texas	1,000	11,000	71,000
Piceance	5,000	31,000	45,000
Corporate	3,000	1,000	—
Total	$676,000	$527,000	$310,000

We continually evaluate our capital needs and compare them to our capital resources. We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes or significant changes in cash flows. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we may adjust our capital budget accordingly or adjust borrowings under our credit facility, as needed.

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Contractual Obligations.

Our contractual obligations as of December 31, 2012 are as follows:

(in millions)	Total	2013	2014	2015	2016	2017	Thereafter
Long-term debt and interest(1)	$2,306.5	$91.1	$284.0	$70.0	$625.6	$58.5	$1,177.3
Asset retirement obligations(2)	86.7	4.4	3.3	3.3	3.2	3.1	69.4
Operating leases(3)	18.0	5.1	5.3	3.6	2.9	1.1	—
Other commitments (4)	23.5	16.2	2.9	2.3	2.1	—	—
Drilling rig commitments(5)	9.4	9.4	—	—	—	—	—
Firm natural gas transportation contracts(6)	245.1	31.0	33.7	33.4	33.5	33.4	80.1
Derivative liabilities(7)	2.4	1.1	0.8	0.5	—	—	—
Total	$2,691.6	$158.3	$330.0	$113.1	$667.3	$96.1	$1,326.8

(1) Long-term debt consists of our 2014 Notes, 2020 Notes, 2022 Notes and outstanding debt under our credit facility, and assumes no principal repayment until the due date of the instruments. Cash interest expense on our credit facility is estimated assuming no principal repayment until the instrument due date and is estimated at a constant interest rate of 2.046%.

(2) The ultimate settlement amounts and the timing of the settlement of such obligations are unknown because they are subject to, among other things, federal, state, local and tribal regulation and economic factors. See Part II, Item 7. "Critical Accounting Policies and Estimates" for a more detailed discussion of the nature of the accounting estimates involved in estimating asset retirement obligations.

(3) Operating leases relate primarily to obligations associated with our office facilities, equipment, vehicles, rail cars and aircraft.

(4) Other commitments relate primarily to natural gas purchases, cogeneration facility management services, California carbon allowance forward purchase contracts and equipment rentals.

(5) We currently have seven drilling rigs under contract that require minimum payments for the full contract term or penalties upon early termination. All these drilling rig contracts expire in 2013. Contracts for all other rigs performing work for us at December 31, 2012 were on a well-by-well basis and could be released without penalty at the conclusion of drilling on the current well, and therefore have not been included in the table above.

(6) We enter into certain firm commitments to transport natural gas production to market and to transport natural gas for use in our cogeneration and conventional steam generation facilities. The remaining terms on these contracts range from one to ten years and require a minimum monthly charge regardless of whether the contracted capacity is used or not.

(7) Derivative liabilities represent the fair value of our derivatives presented as net liabilities in our Balance Sheets as of December 31, 2012. These amounts represent open commodity derivative instruments that were in a current or non-current net liability position with the counterparty at December 31, 2012. Our remaining commodity derivative instruments were in a current or non-current net asset position with the counterparty at December 31, 2012. The ultimate settlement amounts of our derivative liabilities are unknown because they are subject to continuing market fluctuations. See Notes 7 and 8 to the Financial Statements. Also, See Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for further details concerning our derivative activities.

Based on current oil and natural gas prices and anticipated levels of production, we believe that we have sufficient liquidity and capital resources to execute our business plans over the next 12 months and for the foreseeable future. In addition, with our expected cash flow streams, commodity price hedging strategies, current liquidity levels, access to debt and equity markets and flexibility to modify future capital expenditure programs, we expect to be able to fund all planned capital programs, dividend distributions and debt repayments while complying with our debt covenants and meeting any other obligations that may arise from our oil and natural gas operations. However, if our revenue and cash flow decrease in the future as a result of a deterioration in domestic and global economic conditions or a significant decline in commodity prices, we may elect to reduce our planned capital expenditures. We believe that this financial flexibility to adjust our spending levels will provide us with sufficient liquidity to meet our financial obligations. See Part I, Item 1A—"Risk Factors," for a discussion of the risks and uncertainties that affect our financial condition, results of operations and operating cash flows.

Critical Accounting Policies and Estimates.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses and to disclose contingent assets and liabilities at the date of our Financial Statements. We base our assumptions on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. A summary of our significant accounting policies is detailed in Note 1 to our Financial Statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management.

Successful Efforts Method of Accounting. We account for our oil and natural gas exploration and development costs using the successful efforts method. Under this method, the fair value of property acquired and all costs associated with successful exploratory wells and all development wells are capitalized. Items charged to expense generally include geological and geophysical costs, costs of unsuccessful exploratory wells and oil and gas production costs.

Impairment of Oil and Natural Gas Properties. Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. We estimate the expected future cash flows of our oil and natural gas properties and compare these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures and discount rates commensurate with the risk associated with realizing the projected cash flows.

Unproved oil and natural gas properties are periodically assessed for impairment on a project-by-project basis. The impairment assessment is affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, we will recognize an impairment loss at that time.

Oil and Natural Gas Reserves. Estimated proved reserves included in this Annual Report on Form 10-K were prepared by DeGolyer and MacNaughton (D&M), an independent petroleum engineering consulting firm that has provided consulting services throughout the world for over 70 years. There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve engineering is a process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition to the physical factors such as the results of drilling, testing and production subsequent to the date of an estimate, economic factors such as changes in commodity prices or development and production expenses, may require revision of such estimates. Accordingly, oil and natural gas quantities ultimately recovered will vary from reserve estimates. See Part I, Item 1A—"Risk Factors," for a description of some of the risks and uncertainties associated with our business and reserves.

DD&A—Oil and Natural Gas Production. Our rate of recording DD&A—oil and natural gas production is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions and future projections. If the estimates of total proved or proved developed reserves decline, the rate at which we record DD&A—oil and natural gas production expense increases, which in turn reduces our net income. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

Capitalized Interest. Acquisition costs of proved undeveloped and unproved properties qualify for interest capitalization during a period if interest cost is incurred and activities necessary to bring the properties into a productive state are in progress. As wells are drilled in a field with proved undeveloped or unproved reserves, a portion of the acquisition costs are either re-designated as proved developed or expensed, as appropriate. In fields with multiple potential drilling sites, we determine the amount of the acquisition cost to re-designate or expense through a systematic and rational basis that considers the total expected wells to be drilled in that field.

Valuations of Business Combinations. In connection with a purchase business combination, the assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the cost of an acquired entity, if any, over the net amounts assigned to assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is recognized immediately to earnings as a gain from bargain purchase.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved oil and natural gas properties. Due to the unavailability of relevant comparable market data, a discounted cash flow method is used to determine the fair value of proved properties. The discounted cash flow method estimates future cash flows based on management’s expectations of future recoverable proved and risk-adjusted probable reserves, commodity prices based on commodity futures price strips, production timing, drilling and production costs and a risk-adjusted discount rate.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A—oil and natural gas production, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. The likelihood of impairment increases if future commodity prices or reserves quantities are lower than those originally used to determine fair value or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

Derivatives and Hedging. We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. All derivative instruments are recorded on the Balance Sheets at fair value, other than the derivative instruments that meet the “normal purchase normal sales” exclusion. If hedge accounting is not elected, changes in fair value are recognized immediately in earnings. We have elected not to use hedge accounting for our derivative instruments and, as a result, all changes in the fair values of our derivative instruments are recognized immediately in earnings under the caption realized and unrealized (gain) loss on derivatives, net.

We value our derivative instruments using industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and contractual prices for the underlying instruments, as well as other relevant economic measures. The discount rate used in the fair values of these instruments includes a measure of nonperformance risk by the counterparty or us, as appropriate. We utilize the counterparties’ valuations to assess the reasonableness of our valuations. The values we report in our Financial Statements change as these estimates are revised to reflect changes in market conditions (particularly those for oil and natural gas futures), actual results, or other factors, many of which are beyond our control.

Due to the volatility of oil and natural gas prices, the estimated fair values of our derivative instruments are subject to large fluctuations from period to period. See Part II, Item 7A—"Quantitative and Qualitative Disclosures about Market Risk" for a sensitivity analysis of the change in net fair values of our commodity derivatives based on a hypothetical change in commodity prices.

Income Taxes and Uncertain Tax Positions. Income taxes are recorded for the income tax effects of transactions reported in the financial statements and consist of income taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are also recognized for income tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying currently enacted income tax rates to the differences between the financial statements and income tax reporting. We routinely assess the realizability of our deferred income tax assets, and we recognize a valuation allowance if we determine that deferred income tax assets may not be fully utilized in future periods. We consider future taxable earnings in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable earnings, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices). There can be no assurance that facts and circumstances will not materially change and require us to establish deferred income tax asset valuation allowances in a future period. We are subject to taxation in many jurisdictions, and the calculation of our income tax liabilities involves dealing with uncertainties in the application of complex income tax laws and regulations in various taxing jurisdictions. We recognize liabilities for certain income tax positions that meet a more-likely-than not recognition threshold. If we ultimately determine that the payment of these liabilities will be unnecessary, we will reverse the liability and recognize an income tax benefit during the period in which we determine the liability no longer applies.

Asset Retirement Obligations. Our asset retirement obligations (AROs) relate to future costs associated with the plugging and abandonment of oil and natural gas wells, removal of equipment facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and natural gas asset. The recognition of the ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities; amounts and timing of settlements; the credit-adjusted-risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact net earnings as accretion expense. The related capital cost, including revisions thereto, is charged to expense through DD&A—oil and natural gas production over the life of the oil and natural gas field.

Electricity Cost Allocation. Our investment in our cogeneration facilities has been for the express purpose of lowering steam costs in our California heavy oil operations and securing operating control of the respective steam generation. Such cogeneration operations produce electricity and steam and use natural gas as fuel. We allocate steam costs to our oil and natural gas operating costs based on the conversion efficiency (of fuel to electricity and steam) of the cogeneration facilities plus certain direct costs in producing steam. Electricity revenue represents sales to the utilities. A portion of the capital costs of the cogeneration facilities is allocated to DD&A—oil and natural gas production.

Environmental Remediation Liability. We review, on a quarterly basis, our estimates of costs of the cleanup of various sites including sites in which governmental agencies have designated us as a potentially responsible party. When it is probable that obligations have been incurred and where a minimum cost or a reasonable estimate of the cost of remediation can be determined, the applicable amount is accrued. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is an estimation process that includes the judgment of management. In many cases, management's judgment is based on the advice and opinions of legal counsel and other advisers and the interpretation of laws and regulations, which can be interpreted differently by regulators or courts of law. Our experience and the experience of other companies in dealing with similar matters influence the decision of management as to how it intends to respond to a particular matter. A change in estimate could impact our oil and natural gas operating costs and the related liability, if applicable, recorded on our Balance Sheets.

Recently Issued Accounting Standard Updates.

For further information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, see Note 1 to the Financial Statements.

Reconciliation of Non-GAAP Measures.

Discretionary Cash Flow. Discretionary cash flow consists of cash provided by operating activities before changes in working capital items. Management uses discretionary cash flow as a measure of liquidity and believes it provides useful information to investors because it assesses cash flow from operations for each period before changes in working capital, which fluctuates due to the timing of collections of receivables and the settlements of liabilities. The following table provides a reconciliation of discretionary cash flow to cash provided by operating activities, the most directly comparable GAAP measure, for the periods presented.

	Year Ended December 31:		
(in thousands)	2012	2011	2010
Net cash provided by operating activities	$501,439	$455,899	$367,237
Net increase (decrease) in current assets	12,943	26,294	(12,502)
Net increase in current liabilities including book overdraft	(32,677)	(20,302)	(12,681)
Cash premiums for repurchases of notes	34,700	—	—
Cash settlements from early termination of natural gas derivatives	(14,700)	—	—
Cash settlements from early termination of interest rate derivatives	—	—	10,800
Recovery of Flying J bad debt	—	—	38,500
Discretionary cash flow	$501,705	$461,891	$391,354

Operating Margin per BOE. Operating margin per barrel consists of oil and natural gas revenues less oil and natural gas operating expenses and production taxes divided by the total BOEs produced during the period. Management uses operating margin per barrel as a measure of profitability and believes it provides useful information to investors because it relates our oil and natural gas revenue and oil and natural gas operating expenses to our total units of production providing a gross margin per unit of production, allowing investors to evaluate how our profitability varies on a per unit basis each period.

Year Ended December 31:

(per BOE)	2012	2011	2010
Average sales price including cash derivative settlements	$72.18	$65.68	$53.84
Average operating costs—oil and natural gas production	20.43	18.22	15.92
Average production taxes	2.96	2.58	1.93
Average operating margin	$48.79	$44.88	$35.99

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Our primary market risk exposure is the commodity pricing applicable to our oil and gas production. Crude oil and natural gas are commodities; therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. The prices that we receive for our production or pay to purchase natural gas used to generate steam in California depend on numerous factors outside our control. In order to reduce the impact of fluctuations in commodity prices, or to ensure adequate cash flow to fund our development plans and to manage returns on acquisitions and our drilling program, we make use of a commodity hedging strategy. The amount of commodity derivatives that we enter into depend on various factors, including management's view of future crude oil and natural gas prices, our future financial commitments, as well as considerations of other factors.

Currently, our derivatives are primarily in the form of three-way costless collars. However, we may use a variety of derivative instruments in the future to hedge WTI or other oil or natural gas price indices. A three-way collar is a combination of three options. The base structure is a normal collar. A short option is added to fund the improvement of the long strike in the base collar. For oil sales three-way collars, a purchased put and a sold call comprise the base collar. A sold put below is added to fund the raising of the strike on the purchased put. The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (the ceiling) we will receive for the volumes under contract. For natural gas purchase three-way collars, a purchased call and a sold put comprise the base collar. A sold call above is added to fund the lowering of the strike on the purchased call. The purchased call establishes a maximum price unless the market price rises above the sold call, at which point the maximum price would be NYMEX plus the difference between the purchased call and the sold call strike price. The sold put establishes a minimum price (the floor) we will pay for the volumes under contract.

As of December 31, 2012, we had approximately 60% and 20% of our expected 2013 and 2014 oil production, respectively, hedged. A hypothetical $10 increase in the oil prices used and $1 increase in the natural gas prices used to calculate the fair values of our derivative instruments at December 31, 2012 would decrease the fair value of our crude oil derivative instruments by $65.9 million and would increase the fair value of our natural gas derivative instruments by $2.2 million. A hypothetical $10 decrease in the oil prices used and $1 decrease in the natural gas prices used to calculate the fair values of our derivative instruments at December 31, 2012 would increase the fair value of our crude oil derivative instruments by $59.6 million and would decrease the fair value of our natural gas derivative instruments by $1.5 million.

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The following table summarizes our commodity hedge positions as of December 31, 2012:

Term	Average Barrels Per Day	Sold Put / Purchased Put / Sold Call
Crude Oil Sales (NYMEX WTI) Three-Way Collars		
Full year 2013	1,000	$65.00/$85.00/$95.00
Full year 2013	1,000	$65.00/$85.00/$97.25
Full year 2013	1,000	$70.00/$87.00/$105.00
Full year 2013	1,000	$70.00/$88.00/$106.00
Full year 2013	1,000	$60.00/$80.00/$103.30
Full year 2013	1,000	$70.00/$88.15/$100.00
Full year 2013	1,000	$70.00/$86.85/$100.00
Full year 2013	1,000	$69.70/$85.00/$100.00
Full year 2013	1,000	$70.00/$87.00/$108.50
Full year 2013	1,000	$70.00/$90.00/$116.50
Full year 2013	1,000	$70.00/$95.00/$120.10
Full year 2013	500	$70.00/$90.00/$100.00
Full year 2013	500	$70.00/$90.00/$100.00
Full year 2013	1,000	$75.00/$90.00/$101.85
Full year 2013	800	$75.00/$95.00/$101.70
Full year 2013 and 2014	1,000	$70.00/$90.00/$100.00
Full year 2013 and 2014	1,000	$70.00/$90.00/$120.00
Full year 2013 and 2014	1,000	$77.95/$105.00/$115.00
Full year 2013 and 2014	1,000	$80.00/$107.00/$119.60
Full year 2014	1,000	$70.00/$90.00/$121.80
Full year 2014	1,500	$70.00/$90.00/$100.00
Full year 2014 and 2015	1,000	$70.00/$90.00/$104.85
Full year 2015	2,000	$70.00/$90.00/$100.00
Crude Oil Sales (ICE Brent) Three-Way Collars		
Full Year 2013	1,000	$80.00/$100.00/$115.00

Term	Average MMBtu/D or MMTCDE	Average Prices
Natural Gas Purchases (NYMEX SoCal Border) Purchased Calls		
Full year 2013	5,000	$3.50
Natural Gas Purchases (NYMEX SoCal Border) Three-Way Collars		
Full year 2013	1,000	$2.90 / $4.00 / $5.00
Full year 2013	1,000	$2.96 / $4.25 / $5.25
Full year 2013	1,000	$2.70 / $4.00 / $5.00
Full year 2013	2,000	$3.03 / $4.25 / $5.25

Excluded from the table above are our calendar month average swaps, which protect us from variances in market pricing conditions of certain of our sales contracts. These derivative contracts protect 5,000 BOE/D of our Permian sales volumes and have differentials of $0.070 to $0.075 during 2013.

Interest Rate Risk

Our credit facility allows us to fix the interest rate for all or a portion of the principal balance for a period up to 12 months. To the extent the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the credit facility that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate debt. At December 31, 2012, our outstanding principal balance under our credit facility was $562.9 million and the weighted average interest rate on the outstanding principal balance was 2.046%. At December 31, 2012, the carrying amount approximated fair market value. Market risk is estimated as the change in fair value resulting from a hypothetical 100 basis point change in the interest rate on the outstanding balance under our credit facility. Assuming a constant debt level of $1.7 billion, the cash flow impact resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $3.7 million over a 12-month time period.

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Item 8. Financial Statements and Supplementary Data

Financial statement schedules have been omitted since they are either not required, are not applicable, or the required information is shown in the Financial Statements and related notes.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Berry Petroleum Company:

In our opinion, the financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Berry Petroleum Company at December 31, 2012, and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
February 28, 2013

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BERRY PETROLEUM COMPANY
Balance Sheets
December 31, 2012 and 2011
(In Thousands, Except Share Data)

	2012	2011
ASSETS		
Current assets:		
Cash and cash equivalents	$312	$298
Short-term investments	125	65
Accounts receivable	122,159	115,952
Deferred income taxes	703	13,779
Derivative instruments	14,661	6,117
Assets held for sale	—	14,622
Prepaid expenses and other	19,065	16,801
Total current assets	157,025	167,634
Oil and natural gas properties (successful efforts basis), buildings and equipment, net	3,128,502	2,531,393
Derivative instruments	10,891	7,027
Other assets	28,984	28,898
	$3,325,402	$2,734,952
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$175,893	$126,489
Revenue and royalties payable	57,021	49,253
Accrued liabilities	51,151	39,829
Derivative instruments	1,111	20,365
Deferred income taxes	1,456	—
Total current liabilities	286,632	235,936
Long-term liabilities:		
Deferred income taxes	255,471	185,450
Senior secured revolving credit facility	562,900	531,500
8.25% Senior subordinated notes due 2016	—	200,000
10.25% Senior notes due 2014, net of unamortized discount of $2,340 and $6,564, respectively	202,917	348,692
6.75% Senior notes due 2020	300,000	300,000
6.375% Senior notes due 2022	600,000	—
Asset retirement obligations	82,316	59,256
Derivative instruments	1,239	15,505
Other long-term liabilities	19,136	17,884
	2,023,979	1,658,287
Commitments and contingencies (Note 10)		
Shareholders' equity:		
Preferred stock, $0.01 par value, 2,000,000 shares authorized; no shares outstanding	—	—
Capital stock, $0.01 par value:		
Class A Common Stock, 100,000,000 shares authorized; 52,428,423 and 52,067,994 shares issued and outstanding, respectively	524	521
Class B Stock, 3,000,000 shares authorized; 1,763,866 and 1,797,784 shares issued and outstanding, respectively (liquidation preference of $0.50 per share)	18	18
Capital in excess of par value	364,710	350,158

Accumulated other comprehensive loss	—	(5,517)
Retained earnings	649,539	495,549
Total shareholders' equity	1,014,791	840,729
	$3,325,402	$2,734,952

The accompanying notes are an integral part of these Financial Statements.

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BERRY PETROLEUM COMPANY
Statements of Operations
Years ended December 31, 2012, 2011 and 2010
(In Thousands, Except Per Share Data)

	2012	2011	2010
REVENUES			
Oil and natural gas sales	$937,261	$870,773	$619,608
Electricity sales	29,940	34,953	34,740
Natural gas marketing	7,631	13,832	22,162
Gain on sale of assets	1,782	—	—
Settlement of Flying J bankruptcy claim	—	—	21,992
Interest and other income, net	1,985	1,784	3,300
	978,599	921,342	701,802
EXPENSES			
Operating costs—oil and natural gas production	272,180	237,296	189,809
Operating costs—electricity generation	19,975	25,690	31,295
Production taxes	39,374	33,617	22,999
Depreciation, depletion & amortization—oil and natural gas production	225,892	213,859	179,432
Depreciation, depletion & amortization—electricity generation	1,808	1,963	3,225
Natural gas marketing	6,873	13,038	19,896
General and administrative	71,766	61,727	52,846
Interest	83,136	72,807	66,541
Dry hole, abandonment, impairment and exploration	20,931	5,482	2,720
Impairment of oil and natural gas properties	79	625,564	—
Extinguishment of debt	41,545	15,544	573
Realized and unrealized (gain) loss on derivatives, net	(64,620)	(13,908)	31,847
Gain on purchase	—	(1,046)	—
Transaction costs on acquisitions	—	—	2,635
Bad debt recovery	—	—	(38,508)
	718,939	1,291,633	565,310
Earnings before income taxes	259,660	(370,291)	136,492
Income tax provision (benefit)	88,121	(142,228)	53,968
Net earnings (loss)	$171,539	$(228,063)	$82,524
Basic net earnings (loss) per share	$3.11	$(4.21)	$1.54
Diluted net earnings (loss) per share	$3.09	$(4.21)	$1.52
Dividends per share	$0.32	$0.31	$0.30

The accompanying notes are an integral part of these Financial Statements.

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BERRY PETROLEUM COMPANY
Statements of Comprehensive Earnings (Loss)
Years ended December 31, 2012, 2011 and 2010
(In Thousands)

	Year Ended December 31,		
	2012	2011	2010
Net earnings (loss)	$171,539	$(228,063)	$82,524
Other comprehensive earnings, net of income taxes:			
Amortization of accumulated other comprehensive loss related to de-designated hedges, net of income tax benefits of $3,382, $23,467 and $10,153, respectively	5,517	38,289	16,566
Other comprehensive earnings	$5,517	$38,289	$16,566
Comprehensive earnings (loss)	$177,056	$(189,774)	$99,090

The accompanying notes are an integral part of these Financial Statements.

BERRY PETROLEUM COMPANY
Statements of Shareholders' Equity
Years Ended December 31, 2012, 2011 and 2010
(In Thousands)

	Class A	Class B	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balances at January 1, 2010	$430	$18	$89,068	$674,115	$ (60,372)	$703,259
Issuance of stock	80	—	224,233			224,313
Stock options and restricted stock issued	4	—	4,398	—	—	4,402
Stock based compensation expense	—	—	9,386	—	—	9,386
Income tax effect of stock option exercises	—	—	284	—	—	284
Dividends ($0.30 per share)	—	—	—	(16,181)	—	(16,181)
Net earnings	—	—	—	82,524	—	82,524
Amortization of accumulated other comprehensive loss related to de-designated hedges, net of income taxes	—	—	—	—	16,566	16,566
Balances at December 31, 2010	514	18	327,369	740,458	(43,806)	1,024,553
Stock options and restricted stock issued	7	—	10,106	—	—	10,113
Stock based compensation expense	—	—	9,636	—	—	9,636
Income tax effect of stock option exercises	—	—	3,047	—	—	3,047
Dividends ($0.31 per share)	—	—	—	(16,846)	—	(16,846)
Net loss	—	—	—	(228,063)	—	(228,063)
Amortization of accumulated other comprehensive loss related to de-designated hedges, net of	—	—	—	—	38,289	38,289

income taxes						
Balances at December 31, 2011	521	18	350,158	495,549	(5,517)	840,729
Stock options and restricted stock issued	3	—	3,684	—	—	3,687
Stock based compensation expense	—	—	9,819	—	—	9,819
Income tax effect of stock option exercises	—	—	1,049	—	—	1,049
Dividends ($0.32 per share)	—	—	—	(17,549)	—	(17,549)
Net earnings	—	—	—	171,539	—	171,539
Amortization of accumulated other comprehensive loss related to de-designated hedges, net of income taxes	—	—	—	—	5,517	5,517
Balances at December 31, 2012	$524	$18	$364,710	$649,539	$ —	$1,014,791

The accompanying notes are an integral part of these Financial Statements.

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BERRY PETROLEUM COMPANY
Statements of Cash Flows
Years Ended December 31, 2012, 2011 and 2010
(In Thousands)

	2012	2011	2010
Cash flows from operating activities:			
Net earnings (loss)	$171,539	$(228,063)	$82,524
Depreciation, depletion and amortization	227,700	215,822	182,657
Gain on purchase	—	(1,046)	—
Gain on sale of assets	(1,782)	—	—
Extinguishment of debt	6,842	4,072	573
Amortization of debt issuance costs and net discount	7,031	8,243	8,481
Impairment of oil and natural gas properties	79	625,564	—
Dry hole and impairment	14,945	4,616	1,478
Derivatives	(36,135)	(29,094)	42,609
Stock-based compensation expense	9,819	9,636	9,386
Deferred income taxes	82,881	(149,279)	54,698
Other, net	(1,628)	1,420	(1,844)
Allowance for bad debt	414	—	—
Bad debt recovery	—	—	(38,508)
Change in book overdraft	(1,220)	(156)	528
Changes in operating assets and liabilities:			
Accounts receivable	(6,740)	(23,526)	20,055
Inventories, prepaid expenses and other current assets	(6,203)	(2,768)	(7,553)
Accounts payable and revenue and royalties payable	19,967	25,019	5,273
Accrued interest and other accrued liabilities	13,930	(4,561)	6,880
Net cash provided by operating activities	501,439	455,899	367,237
Cash flows from investing activities:			
Development and exploration of oil and natural gas properties	(675,951)	(527,112)	(310,139)
Property acquisitions	(78,313)	(158,090)	(334,409)
Capitalized interest	(17,915)	(29,117)	(28,321)
Proceeds from sale of assets	17,307	—	—
Deposits on asset sales	(3,300)	3,300	—
Net cash used in investing activities	(758,172)	(711,019)	(672,869)
Cash flows from financing activities:			
Proceeds from issuances on line of credit	—	406,600	316,000
Repayments of borrowings under line of credit	—	(411,900)	(310,700)
Proceeds from issuance of 6.375% senior notes due 2022	600,000	—	—
Proceeds from issuance of 10.25% senior notes due 2014	—	—	300,000
Repurchase of 8.25% Senior subordinated notes due 2016	(200,000)	—	—
Repurchase of 10.25% senior notes due 2014	(149,999)	(94,744)	—
Long-term borrowings under credit facility	1,467,200	719,700	363,000
Repayments of long-term borrowings under credit facility	(1,435,800)	(358,200)	(565,000)
Financing obligation	(417)	(380)	(346)
Debt issuance costs	(11,424)	(2,250)	(15,173)
Dividends paid	(17,549)	(16,846)	(16,181)
Proceeds from issuance of stock	—		