EPL OIL & GAS, INC.
Form 10-KT
September 24, 2014

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

Form 10-K

(Mark One)

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

For the fiscal year ended

or

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

For the transition period from January 1, 2014 to June 30, 2014

Commission file number: 001-16179

EPL Oil & Gas, Inc.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	72-1409562 **(I.R.S. Employer Identification No.)**
919 Milam Street, Suite 1600, Houston, Texas (Address of principal executive offices)	77002 **(Zip Code)**

(713) 228-0711

Registrant s telephone number, including area code

Securities registered pursuant to Section 12(b) of the Act:
None

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 x No o

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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

Large accelerated filer o	Accelerated filer o
Non-accelerated filer x (Do not check if a smaller reporting company)	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 x

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court.Yes x No o

There is no market for the common stock of EPL Oil & Gas, Inc.

OMISSION OF CERTAIN INFORMATION:

EPL Oil & Gas, Inc. meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format allowed under that General Instruction.

DOCUMENTS INCORPORATED BY REFERENCE:

None

TABLE OF CONTENTS

TABLE OF CONTENTS

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain statements and information in this Transition Report on Form 10-K (this Transition Report) may constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. The words believe, expect, anticipate, plan, intend, foresee, should, would, could or other similar expressions identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments as well as other factors the Company believes are appropriate under the circumstances and their potential effect on us. While management believes that these forward-looking statements are reasonable, such statements are not guarantees of future performance and the actual results or developments anticipated may not be realized or, even if substantially realized, may not have the expected consequences to or effects on the Company s business or results. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Known material factors that could cause actual results to differ materially from those in the forward-looking statements include those described in (1) Part I, Item 1A. Risk Factors and elsewhere in this Transition Report, (2) our reports and registration statements filed from time to time with the Securities and Exchange Commission and (3) other public announcements we make from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date upon which they are made, whether as a result of new information, future events or otherwise.

1

TABLE OF CONTENTS

PART I

Item 1. ***Business***

Overview

EPL Oil & Gas, Inc. (referred to herein as we, our, us, EPL or the Company) was incorporated as a Delawa corporation in January 1998 and is a wholly-owned subsidiary of Energy XXI Gulf Coast, Inc.(EGC), a Delaware corporation and indirect wholly-owned subsidiary of Energy XXI (Bermuda) Limited, an exempted company under the laws of Bermuda (Energy XXI). We operate as an independent oil and natural gas exploration and production company based in Houston, Texas and New Orleans, Louisiana. Effective September 1, 2012, we changed our legal corporate name from Energy Partners, Ltd. to EPL Oil & Gas, Inc. through a short-form merger pursuant to Section 253 of the General Corporation Law of the State of Delaware.

On June 3, 2014, Energy XXI, EGC, Clyde Merger Sub, Inc., a wholly owned subsidiary of EGC (Merger Sub), and EPL, completed the transactions contemplated by the Agreement and Plan of Merger, dated as of March 12, 2014 (as amended, the Merger Agreement), by and among Energy XXI, EGC, Merger Sub, and EPL, pursuant to which Merger Sub was merged with and into EPL with EPL continuing as the surviving corporation (the Merger). Pursuant to the Merger Agreement, at the effective time of the Merger (the Effective Time), the issued and outstanding shares of EPL common stock, par value $0.001 per share (EPL Common Stock), were converted, in the aggregate, into the right to receive merger consideration (the Merger Consideration) consisting of approximately 65% in cash and 35% in shares of common stock of Energy XXI, par value $0.005 per share (Energy XXI Common Stock). The Merger and related matters are addressed in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations.

Our current operations are concentrated in the U.S. Gulf of Mexico shelf (the GoM shelf) focusing on state and federal waters offshore Louisiana, which we consider our core area. We have focused on acquiring and developing assets in this region, because the region is characterized by established exploitation, development and exploration opportunities in both productive horizons and deeper geologic formations. As part of Energy XXI s overall strategy and capital plan, we intend to pursue capital-efficient development and exploration activities in our core area, as well as identify acquisition opportunities that leverage our technical and operational strengths. As of June 30, 2014, we had estimated proved reserves of 89.5 Mmboe, of which 68% were oil and 69% were proved developed. Of these proved developed reserves, 73% were oil reserves.

We produce both oil and natural gas. Throughout this Transition Report, when we refer to total production, total reserves, percentage of production, percentage of reserves, or any similar term, we have converted our natural gas reserves or production into barrel equivalents. For this purpose, six thousand cubic feet of natural gas is equal to one barrel of oil, which is based on the relative energy content of natural gas and oil. Natural gas liquids are aggregated with oil in this Transition Report.

For definitions of oil and natural gas terms used frequently in this Transition Report, please refer to the Glossary of Oil and Natural Gas Terms following the index of Exhibits in Item 15 of Part IV of this Transition Report.

The following summarizes our acquisitions (purchase prices are before economic effective date adjustments):

Acquisitions

On June 3, 2014, we acquired an asset package consisting of certain shallow water GoM shelf oil and natural gas interests in our South Pass 49 field for $230 million (the SP49 Interests);

On March 21, 2014, we were the high bidder on 21 leases at the Central Gulf of Mexico Lease Sale 231. The 21 high bid lease blocks cover a total of 92,030 acres on a gross and net basis and are all located in the shallow Gulf of Mexico within our core area of operations. Our share of the high bids totaled approximately $8.2 million;

2

TABLE OF CONTENTS

On January 15, 2014, we acquired 100% working interest of certain shallow-water central GoM shelf oil and natural gas assets which comprise five leases in the Eugene Island 258/259 field (the EI Interests) for $70.4 million (the Nexen Acquisition);

On September 26, 2013, we acquired an asset package consisting of certain GoM shelf oil and natural gas interests in the West Delta 29 field (the WD29 Interests) for $21.8 million;

On October 31, 2012, we acquired 100% of the membership interests of Hilcorp Energy GOM, LLC (Hilcorp Acquisition), which owned certain shallow water GoM shelf oil and natural gas interests (the Hilcorp Properties) for $550 million. The Hilcorp Properties included three core producing complexes in the Ship Shoal 208, South Pass 78 and South Marsh Island 239 areas;

On May 15, 2012, we acquired an asset package consisting of certain shallow-water GoM shelf oil and natural gas interests in our South Timbalier 41 field for $32.4 million (the ST41 Interests);

On November 17, 2011, we acquired interests in the Main Pass 296/311 complex along with other unit interests in the Main Pass complex and an interest in a Main Pass 295 primary term lease for $38.6 million (the Main Pass Interests); and

On February 14, 2011, we acquired from Anglo-Suisse Offshore Partners, LLC (ASOP) an asset package consisting of certain GoM shelf oil and natural gas interests surrounding the Mississippi River delta and a related gathering system (the ASOP Properties) for $200.7 million. The ASOP Properties included two core producing complexes in the West Delta and Main Pass areas and an interest in the South Pass 49 field.

Dispositions

On April 2, 2013, we sold certain shallow water GoM shelf oil and natural gas interests located within the non-operated Bay Marchand field for total consideration of $62.8 million.

See Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations for more information regarding these transactions.

Available Information

We file or furnish annual, quarterly and current reports and other documents with the Securities and Exchange Commission (the SEC) under the Securities Exchange Act of 1934 (as amended, the Exchange Act). The public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC. The public can obtain any document we file with the SEC at *www.sec.gov*.

Energy XXI maintains a website at *www.exxi.com* that contains information about us, which information is available free of charge, including links to our Annual and Transition Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all related amendments as soon as reasonably practicable after electronically filing such reports with, or furnishing them to the SEC. The Energy XXI website and the information contained in it and connected to it shall not be deemed incorporated by reference into this Transition Report or any other filing that we make with the SEC.

Properties

As of June 30, 2014, we had working interests in 29 producing fields located in the GoM shelf region. The proved reserves and production from these fields are primarily associated with the following core producing areas: Ship Shoal 208, South Pass 49, East Bay, West Delta, South Timbalier, South Pass 78, Eugene Island 258/259, Main Pass and

South Marsh Island 239.

TABLE OF CONTENTS

As of and for the six months ended June 30, 2014, our proved reserves and production from our core producing areas as percentages of our total proved reserves and total production were as follows:

	Proved Reserves	Production
Ship Shoal 208	21 %	16 %
South Pass 49	20	8
East Bay	11	10
West Delta	13	24
South Timbalier	10	7
South Pass 78	5	7
Eugene Island 258/259	5	6
Main Pass	3	5
South Marsh Island 239	3	4

Our Ship Shoal 208 complex is located 110 miles southwest of New Orleans. It contains 27 producing wells in average water depths of approximately 100 feet in three lease blocks. We operate the Ship Shoal 208 complex and own a working interest of 100% of the acreage position in this area.

Our South Pass 49 field is located near the mouth of the Mississippi River. It contains 15 producing wells in water depths of approximately 400 feet. Energy XXI operates and we have a 100% working interest in the acreage position in this area.

Our East Bay area includes the South Pass 24 and 27 fields and is located 89 miles southeast of New Orleans, near the mouth of the Mississippi River. It contains 197 producing wells located along the coastline and in water depths up to approximately 70 feet. We operate this field and own an average 96% working interest in our acreage position in this area.

Our West Delta complex, a legacy producing area, is located 62 miles south southeast of New Orleans. It contains 47 producing wells in water depths ranging from 29 to 87 feet and includes five lease blocks. We operate the West Delta complex and own an average 93% working interest in our acreage position in this area.

Our South Timbalier area includes the South Timbalier 26 and 41 fields located approximately 60 to 72 miles south of New Orleans. It contains 18 producing wells in water depths of approximately 73 feet or less. We operate the South Timbalier 26 and 41 blocks, and we own a 100% working interest in this area.

Our South Pass 78 complex is located 86 miles southeast of New Orleans. It contains 23 producing wells in water depths ranging from approximately 140 to 190 feet in four lease blocks. We operate the South Pass 78 complex and own a working interest of 67% of the acreage position in this area.

Our Eugene Island 258/259 field was acquired in the Nexen Acquisition. This field is comprised of five central GoM shelf leases and contains 21 producing wells. We operate and have a 100% working interest in our acreage position in this area.

Our Main Pass complex is located 98 miles southeast of New Orleans. It contains 33 producing wells in average water depths of approximately 250 feet and includes the Main Pass 296 and 311 fields. We own a non-operated 50% working interest in our acreage position in this area.

Our South Marsh Island 239 complex is located 117 miles southwest of New Orleans. It contains 7 producing wells in water depths of approximately 20 feet in four lease blocks. We operate the complex and own a working interest of 92% in the acreage position in this area.

Our properties include other producing fields offshore Louisiana located in water depths ranging from approximately 18 to 300 feet with working interests ranging from 7% to 100%.

As of June 30, 2014, we also owned interests in 6 undeveloped leases in the deepwater Gulf of Mexico and we have a non-operated interest in one developed lease. Our working interests in our leases in this area ranged from 15% to 33%.

See Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations, for information regarding our oil and gas production, average prices and average costs.

Oil and Natural Gas Reserves

The following table presents our estimated net proved oil and natural gas reserves and the estimated future net revenues and cash flows related to our reserves at June 30, 2014. Our estimates of proved reserves are based on a reserve report prepared as of June 30, 2014 by Netherland, Sewell & Associates, Inc. (NSAI), an independent petroleum engineering firm. Neither PV-10 nor the standardized measure of discounted future net cash flows shown in the table is intended to represent the current market value of the estimated oil and natural gas reserves that we own. Note 18 Supplementary Oil and Natural Gas Disclosures (Unaudited) of the consolidated financial statements in Part II, Item 8 of this Transition Report provides important additional information about our proved oil and natural gas reserves.

We follow the oil and gas reserves estimation and disclosure requirements of the Financial Accounting Standards Board Accounting Standards Codification (ASC) Topic 932, Extractive Activities Oil and Gas (ASC 932), which requires, among other things, that prices used to estimate reserves for SEC disclosure purposes reflect an unweighted, arithmetic average price based upon the closing price on the first day of each of the twelve months during the fiscal year, rather than the year-end price. See Note 18 Supplementary Oil and Natural Gas Disclosures (Unaudited) of the consolidated financial statements in Part II, Item 8 of this Transition Report for additional information regarding reporting related to oil and natural gas reserves under ASC 932.

	As of June 30, 2014 (dollars in thousands)
Total net proved reserves:	
Oil (Mbbls)	60,832
Natural gas (Mmcf)	172,081
Total (Mboe)	89,512
Net proved developed reserves[1]:	
Oil (Mbbls)	45,232
Natural gas (Mmcf)	101,361
Total (Mboe)	62,126
Net proved undeveloped reserves:	
Oil (Mbbls)	15,600
Natural gas (Mmcf)	70,720
Total (Mboe)	27,386
Estimated future net revenues before income taxes[2]	$3,417,460
Present value of estimated future net revenues before income taxes (PV-10)[2][3][5]	$2,482,261
Standardized measure of discounted future net cash flows[4][5]	$1,964,593

(1) Net proved developed non-producing reserves as of June 30, 2014 (13,151 Mbbls and 62,719 Mmcf) were 23,604 Mboe, or 26% of our total proved reserves.

(2) Calculated using oil price of $98.58 per barrel and natural gas price of $4.12 per Mcf held constant for the life of the reserves, computed in accordance with ASC 932, based on the unweighted, arithmetic average of the closing

price on the first day of each of the twelve months during the fiscal year (for purposes of this Transition Report, the period from July 2013 through June 2014), applying historical adjustments, including transportation, quality differentials, and purchaser bonuses, on an individual property basis, to the year-end quantities of estimated proved reserves. The historical adjustments applied to the computed prices are determined by comparing our historical realized price experience with the comparable historical market, or posted, price.

TABLE OF CONTENTS

(3) The present value of estimated future net revenues attributable to our reserves was prepared using constant prices, determined in the manner described in footnote (2), discounted at a rate of 10% per year on a pre-tax basis.

(4) The standardized measure of discounted future net cash flows represents the present value of future cash flows after income taxes discounted at 10% per year, as calculated in accordance with SEC guidelines and pricing.

(5) PV-10 is considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after-tax amount, because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. Because the standardized measure is dependent on the unique tax situation of each company, our calculation may not be comparable to those of our competitors. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis.

As of June 30, 2014, our PUDs comprised 40 drilling locations in 14 fields. The Ship Shoal 208 field accounts for approximately 38% of our total PUDs, with 10,396 Mboe, consisting of 6,019 Mbbls of oil and 26,258 Mmcf of natural gas. The South Pass 49 field accounts for approximately 23% of our total PUDs, with 6,240 Mboe, consisting of 3,916 Mbbls of oil and 13,942 Mmcf of natural gas. The remaining 12 fields account for approximately 1% to 7% of our total PUDs each, with PUDs ranging from 141 Mboe to 2,025 Mboe.

For the six-months ended June 30, 2014, the increase in our PUDs was primarily attributable to five new PUD locations associated with the acquisition of the SP49 Interests with total net PUDs of 4,941 Mboe of proved reserves consisting of 3,179 Mbbls of oil and 10,571 Mmcf of natural gas. An additional six new PUD locations resulted from extensions and discoveries during the six months ended June 30, 2014 comprising 3,067 Mboe, consisting of 2,189 Mbbls of oil and 5,266 Mmcf of natural gas, in the Eugene Island 258/259, South Pass 49, Ship Shoal 208, South Timbalier 26 and West Delta 29 fields, with PUD extensions and discoveries ranging from 338 Mboe to 910 Mboe. During the six months ended June 30, 2014, we drilled nine PUD locations, primarily in the West Delta area and the Ship Shoal 208 field. The nine drilled PUD locations converted to proved developed reserves approximately 3,652 Mboe, consisting of 2,413 Mbbls of oil and 7,432 Mmcf of natural gas, or approximately 16%, of our PUDs at December 31, 2013. We spent approximately $111 million drilling these nine locations.

We expect our PUDs as of June 30, 2014 of 27.4 Mmboe to begin converting from proved undeveloped to proved developed as the planned development projects begin in fiscal year 2015. We project future development costs relating to the development of the PUDs remaining at June 30, 2014 to be approximately $173 million in fiscal 2015, $110 million in fiscal 2016, $93 million in fiscal 2017 and $28 million thereafter.

Qualifications of Primary Internal Engineer and Third Party Engineers

Our former Vice President, Reserves, was the technical person primarily responsible for overseeing the preparation by NSAI of our reserve estimates included in this Transition Report and for compliance with our policies. He is a registered petroleum engineer with extensive experience in reservoir analysis. Subsequent to the Merger, our former Vice President, Reserves, worked with and reported to the Director, Corporate Reserves of Energy XXI, who is now the technical person primarily responsible for overseeing the preparation of our reserve estimates. The Director, Corporate Reserves of Energy XXI, has 16 years of industry experience with positions of increasing responsibility and reports directly to the Chief Financial Officer of Energy XXI.

At the end of each year, our reserve estimates are prepared by outside petroleum engineering firms. As of June 30, 2014, our estimates of proved reserves are based on a reserve report prepared by the independent petroleum engineering firm NSAI, a nationally recognized engineering firm. At June 30, 2014, 100% of our total estimated net proved reserves were prepared by NSAI. The NSAI report is filed as an exhibit to this Transition Report.

6

TABLE OF CONTENTS

NSAI provides a complete range of geological, geophysical, petrophysical and engineering services and has the technical experience and ability to perform these services in any of the onshore and offshore oil and gas producing areas of the world. NSAI has a technical staff of over 70 professionals who are knowledgeable with regard to recognized industry reserves and resource definitions, specifically those set forth by the SEC. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Joseph J. Spellman and Mr. Philip R. Hodgson.

Mr. Spellman has been practicing consulting petroleum engineering at NSAI since 1989. Mr. Spellman is a Licensed Professional Engineer in the State of Texas (No. 73709) and has over 30 years of practical experience in petroleum engineering. He graduated from the University of Wisconsin-Platteville in 1980 with a Bachelor of Science Degree in Civil Engineering. Mr. Hodgson has been practicing consulting petroleum geology at NSAI since 1998. Mr. Hodgson is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 1314) and has over 29 years of practical experience in petroleum geosciences. He graduated from Purdue University in 1982 with a Bachelor of Science Degree in Geology and in 1984 with a Master of Science Degree in Geophysics.

Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

We have internal controls in place to provide assurance of compliance with SEC rules in the determination of our reserve estimates. These controls include:

Corporate policies which require reserve estimates to be in compliance with SEC guidelines;
Data on new discoveries is reviewed by the Director, Corporate Reserves of Energy XXI or his designees, and our outside engineering firm for evaluation and incorporation into our reserve estimates;
Material reserve variances are discussed among the internal reservoir engineers, the Director, Corporate Reserves of Energy XXI, and our outside engineering firm to ensure the best estimate of remaining reserves;
Reserve estimates are reviewed by the Director, Corporate Reserves of Energy XXI, or his designees and certain members of senior management; and
Revisions are communicated to senior management and the Energy XXI board of directors.

As an operator of domestic oil and gas properties, we have filed Department of Energy Form EIA-23, Annual Survey of Oil and Gas Reserves, as required by Public Law 93-275. The differences between the reserves as reported on Form EIA-23 and those reported herein are attributable to the fact that Form EIA-23 requires that an operator report the total reserves attributable to wells that it operates, without regard to percentage ownership and excluding non-operated wells in which it owns an interest.

TABLE OF CONTENTS

The table below sets forth production information for each field that contains 15% or more of our total proved reserves as of June 30, 2014. The Ship Shoal 208 field was acquired in the Hilcorp Acquisition on October 31, 2012 and the table below reflects production for this field subsequent to the date of the Hilcorp Acquisition. On June 3, 2014, we acquired from Energy XXI GOM, LLC additional oil and natural gas interests in our South Pass 49 field. The table below reflects production for this field based on our historical interests in this field prior to the recent acquisition of the additional interests and includes production associated with the additional interests subsequent to June 3, 2014.

	Six Months Ended June 30, 2014	Year Ended December 31, 2013	2012	2011
Ship Shoal 208:				
Oil (Mbbls)	540	658	109	
Natural gas (Mmcf)	547	1,130	199	
Total (Mboe)	631	846	142	
South Pass 49:				
Oil (Mbbls)	138	163	86	91
Natural gas (Mmcf)	1,110	2,512	401	183
Total (Mboe)	323	582	153	122

Costs Incurred in Oil and Natural Gas Activities

The following table sets forth the costs incurred associated with finding, acquiring and developing our proved oil and natural gas reserves.

	Six Months Ended June 30, 2014	Year Ended December 31, 2013	2012	2011
	(In thousands)			
Acquisitions Proved[(1)]	$ 314,169	$ 46,047	$ 706,322	$ 261,812
Acquisitions Unproved	9,503	2,200	7,496	14
Exploration	56,079	46,100	43,338	17,129
Development[(2)]	242,217	303,245	180,938	83,577
Costs incurred	$ 621,968	$ 397,592	$ 938,094	$ 362,532

(1) For the six months ended June 30, 2014, includes $231.3 million associated with the acquisition of the SP 49 Interests (including $1.1 million of assumed asset retirement obligations) and $82.9 million associated with the acquisition of the EI Interests (including $18.2 million of assumed asset retirement obligations). See Note 3 Acquisitions and Dispositions of the consolidated financial statements in Part II, Item 8 of this Transition Report for further information.

(2) Includes our estimates during the years ended December 31, 2013, 2012, and 2011 of incurred asset retirement obligations associated with finding and developing our proved oil and natural gas reserves of $1.2 million, $1.2 million, and $0.2 million, respectively.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of June 30, 2014.

	Total Productive Wells	
	Gross	Net
Oil	359	314
Natural gas	79	58
Total	438	372

Productive wells consist of producing wells and wells capable of production, including oil wells awaiting connection to production facilities and natural gas wells awaiting pipeline connections to commence deliveries. Forty-eight gross oil wells and 11 gross natural gas wells have dual completions.

TABLE OF CONTENTS

In this Transition Report, when referring to wells and acreage, gross refers to the total wells or acres in which we have a working interest and net refers to gross wells or acres multiplied by our working interest.

Acreage

The following table sets forth information relating to acreage held by us as of June 30, 2014. Developed acreage is assigned to producing wells.

	Gross Acreage	Net Acreage
Developed:		
GoM Shelf	304,552	227,282
Deepwater Gulf of Mexico	5,760	1,600
Other	125	125
Total	310,437	229,007
Undeveloped:		
GoM Shelf	73,319	68,999
Deepwater Gulf of Mexico	34,560	9,663
Total	107,879	78,662

We continually assess our undeveloped lease inventory for exploration opportunities and, where appropriate, develop strategies to maintain our inventory by allocating resources to such leases or arranging for the participation of others, including farm-outs and the use of prospect generation consulting geologists. Leases covering 14% of our undeveloped net acreage expire in fiscal year 2015, 9% expire in fiscal year 2016, 40% expire in fiscal year 2018, and 30% expire in fiscal year 2019. The remaining undeveloped net acreage is held by production.

Since December 31, 2013, our net developed acreage decreased 10,376 net acres, or 4%, and our net undeveloped acreage increased 8,577 net acres, or 12%. The decrease in our net developed acreage was attributable to acreage associated with certain GoM shelf leases that expired or were relinquished. The increase in our net undeveloped acreage was primarily due to the acquisition of new GoM shelf leases totaling 10,000 net acres partially offset by an expired lease. In addition, we were awarded new GoM shelf leases covering a total of 82,030 acres on a gross and net basis in July 2014.

Drilling Activity

Drilling activity refers to the number of wells completed at any time during the applicable fiscal years, regardless of when drilling was initiated. The following table shows our drilling activity where gross refers to the total wells in which we have a working interest and net refers to gross wells multiplied by our working interest in these wells.

	Six Months Ended June 30, 2014		Year Ended December 31, 2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells								
Productive	10.0	9.5	13.0	11.5	11.0	9.5	4.0	3.6
Non-productive			3.0	3.0	1.0	1.0	1.0	1.0

Total	10.0	9.5	16.0	14.5	12.0	10.5	5.0	4.6
Exploratory Wells								
Productive	1.0	0.5			1.0	0.8	4.0	1.3
Non-productive	1.0	1.0	1.0	1.0	2.0	0.7	1.0	0.5
Total	2.0	1.5	1.0	1.0	3.0	1.5	5.0	1.8
Recompletion Operations								
Productive	5.0	4.5	17.0	14.4	16.0	14.2	23.0	19.1
Non-productive			4.0	3.7	2.0	2.0	4.0	3.3
Total	5.0	4.5	21.0	18.1	18.0	16.2	27.0	22.4

9

TABLE OF CONTENTS

We also drilled one gross (1.0 net) successful exploratory oil well in our Main Pass 244 field that reached its target depth in September 2013 and is waiting on production facilities to commence production. We recently drilled two gross (2.0 net) development wells, one in our Ship Shoal 208 field and one in our West Delta complex and one gross (1.0 net) recompletion in our South Marsh Island 239 complex. In addition, we are currently in the process of drilling one exploratory well (1.0 net) in our South Timbalier area.

Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, mechanics and materialman s liens, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interfere with the use of our properties or the operation of our business.

We believe that we have satisfactory title to, or rights in, all of our properties. As is customary in the oil and natural gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. We investigate title prior to the consummation of an acquisition of producing properties and before the commencement of drilling operations on undeveloped properties. We have obtained or conducted a thorough title review on substantially all of our producing properties and believe that we have satisfactory title to such properties in accordance with standards generally accepted in the oil and natural gas industry.

Government Regulation

Our oil and gas exploration, production and related operations and activities are subject to extensive rules and regulations promulgated by federal, state and local governmental agencies. Failure to comply with such rules and regulations can result in substantial penalties. Because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. Although the regulatory burden on the oil and 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 others in our industry with similar types, quantities and locations of production.

Regulations affecting production. The jurisdictions in which we operate generally require permits for drilling operations, drilling bonds and operating reports and impose other requirements relating to the exploration and production of oil and gas. Such jurisdictions also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells, the spacing, plugging and abandonment of such wells, restrictions on venting or flaring natural gas and requirements regarding the ratability of production.

These laws and regulations may limit the amount of oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. Moreover, many jurisdictions impose a production or severance tax with respect to the production and sale of oil and natural gas within their jurisdiction. There is generally no regulation of wellhead prices or other, similar direct economic regulation of production, but there can be no assurance that this will remain true in the future.

In the event we conduct operations on federal, state or Indian oil and natural gas leases, our operations may be required to comply with additional regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements, and on-site security regulations and other appropriate permits issued by the Bureau of Land Management (BLM) or other relevant federal or state agencies.

Regulations affecting sales. The sales prices of oil, natural gas liquids and natural gas are not presently regulated but rather are set by the market. We cannot predict, however, whether new legislation to regulate the price of energy commodities might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties.

TABLE OF CONTENTS

The Federal Energy Regulatory Commission (FERC) regulates interstate natural gas pipeline transportation rates and service conditions, which affect the marketing of gas we produce, as well as the revenues we receive for sales of such production. The price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting interstate transportation. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. We do not believe that we will be affected by any such FERC action in a manner materially differently than other natural gas producers in our areas of operation.

The price we receive from the sale of oil and natural gas liquids is affected by the cost of transporting those products to market. Rates charged and terms of service for the interstate pipeline transportation of oil, natural gas liquids and other refined petroleum products also are regulated by FERC. FERC has established an indexing methodology for changing the interstate transportation rates for oil pipelines, which allows such pipelines to take an annual inflation-based rate increase. We are not able to predict with any certainty what effect, if any, these regulations will have on us, but, other factors being equal, the regulations may, over time, tend to increase transportation costs which may have the effect of reducing wellhead prices for oil and natural gas liquids.

Market manipulation and market transparency regulations. Under the Energy Policy Act of 2005 (EPAct 2005), FERC possesses regulatory oversight over natural gas markets, including the purchase, sale and transportation of natural gas by any entity in order to enforce the anti-market manipulation provisions in the EPAct 2005. The Commodity Futures Trading Commission (CFTC) also holds authority to regulate certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act. Likewise, the Federal Trade Commission (FTC) holds authority to regulate wholesale petroleum markets pursuant to the Federal Trade Commission Act and the Energy Independence and Security Act of 2007. With regard to our physical purchases and sales of natural gas, natural gas liquids, and crude oil, our gathering or transportation of these energy commodities, and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by FERC, FTC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation or, for the CFTC, triple the monetary gain to the violator, order disgorgement of profits, and recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

FERC has issued certain market transparency rules pursuant to its EPAct 2005 authority, which may affect some or all of our operations. FERC issued a final rule in 2007, as amended by subsequent orders on rehearing (Order 704), which requires wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including natural gas producers, gatherers, processors, and marketers, to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to, the formation of price indices, as explained in the order. It is the responsibility of the reporting entity to determine which transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC s policy statement on price reporting. FERC s civil penalty authority under EPAct 2005 applies to violations of Order 704.

Oil Pipeline Regulations. We own interests in oil pipelines regulated by FERC under the Interstate Commerce Act (ICA), the Energy Policy Act of 1992 (EPAct of 1992), and the rules and regulations promulgated under those laws and, thus, have interstate tariffs on file with FERC setting forth our interstate transportation rates and charges and the rules and regulations applicable to our jurisdictional transportation service. The ICA and its implementing regulations require that tariff rates for interstate service on oil pipelines, including interstate pipelines that transport crude oil, natural gas liquids and refined petroleum products pipelines, be just and reasonable and non-discriminatory and that such rates and terms and conditions of service be filed with FERC. Under the ICA, shippers may challenge new or existing rates or services. FERC is authorized to suspend the effectiveness of a challenged rate for up to seven months, though rates are

11

typically not suspended for the maximum allowable period. A successful rate challenge could result in an oil pipeline paying refunds for the period that the rate was in effect and/or reparations for up to two years prior to the filing of a complaint. FERC generally has not investigated oil pipeline rates on its own initiative.

Under the EPAct of 1992, oil pipeline rates in effect for the 365-day period ending on the date of enactment of the EPAct of 1992 are deemed to be just and reasonable under the ICA, if such rates were not subject to complaint, protest or investigation during that 365-day period. These rates are commonly referred to as grandfathered rates. FERC may change grandfathered rates upon complaint only after it is shown that (i) a substantial change has occurred since enactment in either the economic circumstances or the nature of the services that were a basis for the rate; (ii) the complainant was contractually barred from challenging the rate prior to enactment of the EPAct of 1992 and filed the complaint within 30 days of the expiration of the contractual bar; or (iii) a provision of the tariff is unduly discriminatory or preferential. The EPAct of 1992 places no similar limits on challenges to a provision of an oil pipeline tariff as unduly discriminatory or preferential.

The EPAct of 1992 further required FERC to establish a simplified and generally applicable ratemaking methodology for interstate oil pipelines. As a result, FERC adopted an indexing rate methodology which, as currently in effect, allows oil pipelines to change their rates within prescribed ceiling levels that are tied to changes in the Producer Price Index for Finished Goods, plus 2.65 percent. Rate increases made under the index are subject to protest, but the scope of the protest proceeding is limited to an inquiry into whether the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline s increase in costs. The indexing methodology is applicable to any existing rate, including a grandfathered rate. Indexing includes the requirement that, in any year in which the index is negative, pipelines must file to lower their rates if those rates would otherwise be above the rate ceiling. However, the pipeline is not required to reduce its rates below the level deemed just and reasonable under the EPAct of 1992.

While an oil pipeline, as a general rule, must use the indexing methodology to change its rates, FERC also retained cost-of-service ratemaking, market-based rates, and settlement rates as alternatives to the indexing approach. A pipeline can follow a cost-of-service approach when seeking to increase its rates above the rate ceiling (or when seeking to avoid lowering rates to the reduced rate ceiling), provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can charge market-based rates if it establishes that it lacks significant market power in the affected markets. In addition, a pipeline can establish rates under settlement.

Outer Continental Shelf Regulations. Our operations on federal oil and gas leases in the Gulf of Mexico are subject to regulation by the Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Ocean Energy Management (BOEM), successor agencies to the Minerals Management Service. These leases contain relatively standardized terms and require compliance with detailed BSEE and BOEM regulations and orders issued pursuant to various federal laws, including the Outer Continental Shelf Lands Act (OCSLA). These laws and regulations are subject to change, and many new requirements were imposed by the BSEE and BOEM subsequent to the April 2010 Deepwater Horizon incident. For offshore operations, lessees must obtain BOEM approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the U.S. Environmental Protection Agency, (the EPA), lessees must obtain a permit from the BSEE prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the OCS, calculation of royalty payments and the valuation of production for this purpose, and removal of facilities. To cover the various obligations of lessees on the OCS, such as the cost to plug and abandon wells and decommission and remove platforms and pipelines at the end of production, the BOEM generally requires that lessees post substantial bonds or other acceptable assurances that such obligations will be met, unless the BOEM exempts the lessee from such obligations. The cost of such bonds or other surety can be substantial, and we can provide no assurance that we can continue to obtain bonds or other surety in all cases. As a result of the recent bankruptcy of ATP Oil and Gas, the BOEM has indicated that it may review the estimated cost of future plugging, abandonment, decommissioning and removal obligations of other OCS operators and may increase the amount of financial assurance required with respect to these obligations. Under certain circumstances, the BSEE, a new federal agency created to enforce compliance with safety and environmental rules applicable to OCS activities, may require our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations. We own certain crude oil pipelines located on the OCS. BSEE regulates terms of service on OCS pipelines to provide open and nondiscriminatory access.

Gathering regulations. Section 1(b) of the federal Natural Gas Act (NGA) exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. Although FERC has not made any formal determinations with respect to any of the natural gas gathering pipeline facilities that we own, we believe that our natural gas gathering pipelines meet the traditional tests that FERC has used to establish a pipeline s status as a gathering pipeline not subject to FERC jurisdiction. The distinction between FERC-regulated transmission facilities and federally unregulated gathering facilities, however, has been the subject of substantial litigation and, over time, FERC s policy for determining which facilities it regulates has changed. In addition, the distinction between FERC-regulated transmission facilities, on the one hand, and gathering facilities, on the other, is a fact-based determination made by FERC on a case-by-case basis. The classification and regulation of our gathering lines may be subject to change based on future determinations by FERC, the courts or the U.S. Congress.

State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and in some instances complaint-based rate regulation. Our gathering operations may also be subject to state ratable take and common purchaser statutes, designed to prohibit discrimination in favor of one producer over another or one source of supply over another. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies. In addition, our natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services, though we do not believe that we would be affected by any such action in a manner differently than other companies in our areas of operation.

Environmental Regulations

Various federal, state and local laws and regulations relating to the protection of the environment, including the discharge of materials into the environment, may affect our exploration, development and production operations and the costs of those operations. These laws and regulations, among other things, govern the amounts and types of substances that may be released into the environment, the issuance of permits to conduct exploration, drilling and production operations, the handling, discharge and disposition of waste materials, the reclamation and abandonment of wells, sites and facilities, the establishment of financial assurance requirements for oil spill response costs and the decommissioning of offshore facilities and the remediation of contaminated sites. These laws and regulations may impose liabilities for noncompliance and contamination resulting from our operations and may require suspension or cessation of operations in affected areas.

The environmental laws and regulations applicable to us and our operations include, among others, the following United States federal laws and regulations:

- Clean Air Act, and its amendments, which governs air emissions;
- Clean Water Act, which governs discharges of pollutants into waters of the United States;
- Comprehensive Environmental Response, Compensation and Liability Act, which imposes strict liability where releases of hazardous substances have occurred or are threatened to occur (commonly known as Superfund);
- Resource Conservation and Recovery Act, which governs the management of solid waste;

Endangered Species Act, Marine Protected Areas, Marine Mammal Protection Act, Migratory Bird Treaty Act, which governs the protection of animals, flora and fauna;

Oil Pollution Act of 1990, which imposes liabilities resulting from discharges of oil into navigable waters of the United States;

13

Emergency Planning and Community Right-to-Know Act, which requires reporting of toxic chemical inventories; and Safe Drinking Water Act, which governs underground injection and disposal activities; and U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

We believe our operations are in compliance with applicable environmental laws and regulations. We expect to continue making expenditures on a regular basis relating to environmental compliance. We maintain insurance coverage for spills, pollution and certain other environmental risks, although we are not fully insured against all such risks. Our insurance coverage provides for the reimbursement to us of costs incurred for the containment and clean-up of materials that may be suddenly and accidentally released in the course of our operations, but such insurance does not fully insure pollution and similar environmental risks. We do not anticipate that we will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on our consolidated financial position or our results of operations. However, since environmental costs and liabilities are inherent in our operations and in the operations of companies engaged in similar businesses and since regulatory requirements frequently change and may become more stringent, there can be no assurance that material costs and liabilities will not be incurred in the future. Such costs may result in increased costs of operations and acquisitions and decreased production.

Oil Pollution Act. The Oil Pollution Act of 1990 (OPA) and regulations adopted pursuant to OPA impose a variety of requirements on responsible parties related to the prevention of and response to oil spills into waters of the United States, including the OCS. A responsible party includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA subjects owners of oil handling facilities to strict, joint and several liability for all containment and cleanup costs and a variety of public and private damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters and natural resource damages. Although defenses exist to the liability imposed by OPA, they are limited. OPA also requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. OPA currently requires a minimum financial responsibility demonstration of $35 million for companies operating on the OCS, although the Secretary of Interior may increase this amount up to $150 million in certain situations. We cannot predict at this time whether OPA will be amended or whether the level of financial responsibility required for companies operating on the OCS will be increased. In any event, if there were to occur an oil discharge or substantial threat of discharge, we may be liable for costs and damages, which costs and liabilities could be material to our results of operations and financial position.

Climate Change. In December 2009, the U.S. Environmental Protection Agency (the EPA) determined that emissions of carbon dioxide, methane and other greenhouse gases 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 greenhouse gases under existing provisions of the Clean Air Act (CAA). Among the EPA s rules regulating greenhouse gas emissions under the CAA, one requires a reduction in emissions of greenhouse gases from motor vehicles and another regulates emissions of greenhouse gases from certain large stationary sources. The EPA has also adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries and certain onshore and offshore oil and natural gas production facilities.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. 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. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases 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 and results of operations.

Plugging, Abandonment and Decommissioning. We are responsible for plugging and abandoning wellbores and decommissioning associated platforms, pipelines and facilities on our oil and natural gas properties. Some of our offshore operations are conducted on federal leases that are administered by the BOEM and are required to comply with the regulations and orders promulgated by the BOEM and BSEE under OCSLA.

We are subject to an active Notice to Lessees and Operators (NTL) issued by the BSEE, effective October 15, 2010, on the decommissioning of wells and platforms. The NTL imposes more stringent requirements for decommissioning facilities that pose a hazard to safety or the environment, as well as for facilities that are not useful for lease operations and that are not capable of oil and natural gas production in paying quantities. Historically, approval was granted to operators to maintain these structures in order to conduct future activities. However, the NTL significantly restricts this practice. Under the NTL, lessees must submit an application to permanently plug any well that poses a hazard to safety or the environment within 30 days after identifying the hazard. The NTL also imposes new deadlines for removing platforms or other facilities that are no longer useful for operations. Furthermore, the NTL imposes new deadlines for plugging, abandoning or performing downhole zonal isolation on wells that are no longer useful for operations and that are no longer capable of production in paying quantities. We submit an annual plan for our wellbore plugging and abandonment and decommissioning activities.

The effects of Hurricanes Katrina and Rita during the 2005 hurricane season and Hurricanes Ike and Gustav in 2008 significantly impacted oil and gas operations on the OCS. The effects included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs. Both the BOEM and the BSEE are concerned about the potential for catastrophic damage to key infrastructure and the resultant pollution from future storms. In an effort to reduce the potential for future damage, the former BOEMRE issued still active guidance through NTLs, aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures. It is possible that similar, if not more stringent, design and operational requirements will be issued by the BOEM or BSEE in the future and these new requirements could increase our operating costs. The BOEM, BSEE and other regulatory bodies, including those regulating the decommissioning of our pipelines and facilities under the jurisdiction of the state of Louisiana, may change their requirements or enforce requirements in a manner inconsistent with our expectations, which could materially increase the cost of such activities and/or accelerate the timing of cash expenditures and could have a material adverse effect on our financial position, results of operations and cash flows.

The failure to comply with these rules and regulations could result in substantial penalties, including lease termination in the case of federal leases. Under limited circumstances, the BSEE could require us to suspend or terminate our operations on a federal lease or we could have difficulty entering into new leases in the future. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations, although the impact of those requirements may vary significantly based on the nature and location of operations and related pipelines and facilities.

TABLE OF CONTENTS

Marketing and Significant Customers

We market substantially all of our oil and natural gas production. We sell our natural gas to marketing companies pursuant to a variety of contractual arrangements, generally under contracts with terms no longer than six to twelve months. Pricing on those contracts is based largely on published regional index pricing. We sell our oil under contracts with month-to-month terms to a variety of purchasers. The pricing for oil is based upon the posted prices set by major purchasers in the production area, reporting publications, or upon New York Mercantile Exchange (NYMEX) pricing. Oil pricing is adjusted for quality and transportation differentials. Oil and natural gas purchasers are selected on the basis of price, credit quality and service reliability.

Our oil, condensate and natural gas production is sold to a variety of purchasers, historically at market-based prices. We believe that the prices for liquids and natural gas are comparable to market prices in the areas where we have production. Of our total oil and natural gas revenues for the period January 1, 2014 through June 3, 2014, Chevron USA (Chevron), Inc. accounted for approximately 52%, ConocoPhillips accounted for approximately 23%, and Shell Trading (US) Company (Shell) accounted for approximately 10%. Of our total oil and natural gas revenues for the period June 4, 2014 through June 30, 2014, Chevron accounted for approximately 55%, ConocoPhillips accounted for approximately 23%, and Shell accounted for approximately 11%. Due to the nature of the markets for oil and natural gas, we do not believe that the loss of any one of these customers would have a material adverse effect on our financial condition or results of operations, although a temporary disruption in production revenues could occur.

Employees

As of June 30, 2014, we had 208 full-time employees, including 42 geoscientists, engineers and technicians and 116 field personnel. Our employees are not represented by any labor union or other collective bargaining organization. We consider relations with our employees to be satisfactory and we have never experienced a work stoppage or strike. We regularly use independent consultants and contractors to perform various professional services in various areas, including in our exploration and development operations, production operations and certain administrative functions.

Competitors

Our competitors include numerous independent oil and gas companies and major oil companies. Many of our larger competitors possess and employ financial and personnel resources substantially greater than ours. These competitors are able to pay more for productive oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to replace and expand our reserve base depends on our ability to attract and retain qualified personnel and identify and acquire suitable producing properties and prospects for future drilling. See Part I, Item 1A, Risk Factors, for additional information about risks related to our competitors, personnel and ability to acquire producing properties and prospects.

Seasonality

Historically, the demand for and price of natural gas generally trends upward during the winter months and downward during the summer months. However, these seasonal fluctuations can be interrupted due to summer storage practices where pipeline companies, utilities, distribution companies and industrial users may purchase and place into storage facilities a portion of their anticipated winter requirements of natural gas. These trends are also disrupted by extreme market impacts such as those that occurred in 2008, when oil and natural gas prices reached peak levels in the summer months, then fell during the winter. Tropical storms and hurricanes generally occur in the Gulf of Mexico during late summer and fall, which may require us to evacuate personnel and shut-in production during those periods. The winds and turbulent current conditions that occur in the winter months can impact our ability to safely load, unload and transport personnel and equipment, and perform operations, including plugging, abandonment and other decommissioning activities, which can delay our operations, increase the cost of our operations and/or delay the restoration and maintenance of our oil and natural gas production.

TABLE OF CONTENTS

Item 1A. ***Risk Factors***

Risks Related to Our Business

The nature of our business involves numerous uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

We engage in exploration and development drilling activities, which are inherently risky. These activities may be unsuccessful for many reasons. In addition to a failure to find oil or natural gas, drilling efforts can be affected by adverse weather conditions such as hurricanes and tropical storms in the Gulf of Mexico, cost overruns, equipment shortages and mechanical difficulties. Therefore, the successful drilling of an oil or gas well does not ensure we will realize a profit on our investment. A variety of factors, both geological and market-related, could cause a well to become uneconomic or only marginally economic. In addition to their costs, unsuccessful wells could impede our efforts to replace reserves.

Our business involves a variety of operating risks, which include, but are not limited to:

- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of gas, oil and formation water;
- natural disasters, such as hurricanes and other adverse weather conditions;
- pipe, cement, subsea well or pipeline failures;
- casing collapses;
- mechanical difficulties, such as lost or stuck oil field drilling and service tools/
- abnormally pressured formations; and
- environmental hazards, such as gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

If we experience any of these problems, well bores, platforms, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations. We could also incur substantial losses due to costs and/or liability incurred as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations.

Our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a single geographic area, making us vulnerable to risks associated with operating in one geographic area.

Unlike other entities that are geographically diversified, we do not have the resources to effectively diversify our operations or benefit from the possible spreading of risks or offsetting of losses. By consummating acquisitions only in the Gulf of Mexico and the U.S. Gulf Coast, our lack of diversification may:

subject us to numerous economic, competitive and regulatory developments, any or all of which may have an adverse impact upon the particular industry in which we operate; and

result in our dependency upon a single or limited number of hydrocarbon basins.

17

TABLE OF CONTENTS

In addition, the geographic concentration of our properties in the Gulf of Mexico and the U.S. Gulf Coast means that some or all of the properties could be affected should the region experience:

- severe weather, such as hurricanes and other adverse weather conditions;
- delays or decreases in production, the availability of equipment, facilities or services;
- delays or decreases in the availability of capacity to transport, gather or process production; and/or
- changes in the regulatory environment.

During the 2008 hurricane season, our production was reduced by approximately 21%, on an annual basis, as a result of damage to third party pipelines caused by two hurricanes. The hurricane damage limited our ability to sell our production from certain properties for extended periods of time during the third and fourth quarters of 2008. If mechanical problems, storms or other events were to curtail a substantial portion of the production in these areas, such a curtailment could have a material adverse effect on our business, financial condition, results of operations and cash flows. In accordance with industry practice, we maintain insurance against some, but not all, of these risks and losses. For additional information, please read Our insurance may not protect us against all of the operating risks to which our business is exposed.

Because all or a number of the properties could experience many of the same conditions at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other producers who have properties over a wider geographic area.

Most of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

We own leasehold interests in areas not currently held by production. Unless production in paying quantities is established on units containing certain of these leases during their terms, the leases will expire. If our leases expire, we will lose our right to develop the related properties.

Our drilling plans for areas not currently held by production are subject to change based upon various factors, including factors that are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. On our acreage that we do not operate, we have less control over the timing of drilling, therefore there is additional risk of expirations occurring in those sections.

Oil and natural gas prices are volatile, and a substantial or extended decline in oil and natural gas prices would adversely affect our financial results and impede our growth.

Our financial condition, revenues, profitability and carrying value of our properties depend upon the prevailing prices and demand for oil and natural gas. Commodity prices also affect our cash flow available for capital expenditures and our ability to access funds under our revolving credit facility and through the capital markets. The amount available for borrowing under our revolving credit facility is subject to a borrowing base, which is determined by our lenders taking into account our estimated proved reserves and is subject to semi-annual redeterminations based on pricing models determined by the lenders at such time. The markets for these commodities are volatile and even relatively modest drops in prices can affect our financial results and impede our growth.

Natural gas and oil prices historically have been volatile and are likely to continue to be volatile in the future, especially given current geopolitical and economic conditions. For example, the WTI crude oil price per barrel for the period between January 1, 2014 and June 30, 2014 ranged from a high of $107.26 to a low of $91.66 and the NYMEX natural gas price per MMBtu for the period January 1, 2014 to June 30, 2014 ranged from a high of $6.15 to a low of $4.01. Prices for oil and natural gas fluctuate widely in response to relatively minor changes in the supply and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control, such as:

- domestic and foreign supplies of oil and natural gas;
- price and quantity of foreign imports of oil and natural gas;

TABLE OF CONTENTS

actions of the Organization of Petroleum Exporting Countries and other state-controlled oil companies relating to oil and natural gas price and production controls;

level of consumer product demand, including as a result of competition from alternative energy sources;

level of global oil and natural gas exploration and productivity;

domestic and foreign governmental regulations;

level of global oil and natural gas inventories;

political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;

weather conditions;

technological advances affecting oil and natural gas production and consumption;

overall U.S. and global economic conditions; and

price and availability of alternative fuels.

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Lower oil and natural gas prices may not only decrease our expected future revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. This may result in us having to make downward adjustments to our estimated proved reserves and could have a material adverse effect on our financial condition and results of operations.

Our actual recovery of reserves may differ from our proved reserve estimates.

This Transition Report contains estimates of our proved oil and gas reserves. Estimating crude oil and natural gas reserves is complex and inherently imprecise. It requires interpretation of the available technical data and making many assumptions about future conditions, including price and other economic conditions. In preparing such estimates, projection of production rates, timing of development expenditures and available geological, geophysical, production and engineering data are analyzed. The extent, quality and reliability of this data can vary. This process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. If our interpretations or assumptions used in arriving at our reserve estimates prove to be inaccurate, the amount of oil and gas that will ultimately be recovered may differ materially from the estimated quantities and net present value of reserves owned by us. Any inaccuracies in these interpretations or assumptions could also materially affect the estimated quantities of reserves shown in the reserve reports summarized in this Transition Report. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses, decommissioning liabilities and quantities of recoverable oil and gas reserves most likely will vary from estimates. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

We may be limited in our ability to maintain or book additional proved undeveloped reserves under the SEC s rules.

We have included in this Transition Report certain estimates of our proved reserves as of June 30, 2014 prepared in a manner consistent with our interpretation of the SEC rules relating to modernizing reserve estimation and disclosure requirements for oil and natural gas companies, as well as the interpretation of our independent petroleum consultant performing an audit of our reserve estimates. Included within these SEC reserve rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years of the date of booking. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Further, if we postpone drilling of proved undeveloped reserves beyond this five-year development horizon, we may have to write off reserves

19

We may be limited in our ability to maintain or book additional provedundeveloped reserves under the SEC s rules previously recognized as proved undeveloped. During the year ended June 30, 2014, we were not required to reduce any proved reserve estimates due to the five year development rule.

As of June 30, 2014, approximately 31% of our total proved reserves were undeveloped and approximately 26% of our total proved reserves were developed non-producing. There can be no assurance that all of those reserves will ultimately be developed or produced.

While we have plans or are in the process of developing plans for exploiting and producing a majority of our proved reserves, there can be no assurance that all of those reserves will ultimately be developed or produced. We are not the operator of approximately 5% of our proved undeveloped reserves (excluding approximately 20% attributable to the South Pass 49 field operated by Energy XXI), so we may not be in a position to control the timing of all development activities. Furthermore, there can be no assurance that all of our undeveloped and developed non-producing reserves will ultimately be produced during the time periods we have planned, at the costs we have budgeted, or at all, which could result in the write-off of previously recognized reserves.

Unless we replace crude oil and natural gas reserves, our future reserves and production will decline.

A large portion of our drilling activity is located in mature oil-producing areas of the GoM shelf. Accordingly, increases in our future crude oil and natural gas production depend on our success in finding or acquiring additional reserves. If we are unable to replace reserves through drilling or acquisitions, our level of production and cash flows will be adversely affected. In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Our ability to make the necessary capital investment to maintain or expand our asset base of crude oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. We also may not be successful in raising funds to acquire additional reserves.

Relatively short production periods or reserve lives for Gulf of Mexico properties subject us to higher reserve replacement needs and may impair our ability to reduce production during periods of low oil and natural gas prices.

High production rates generally result in recovery of a relatively higher percentage of reserves from properties in the Gulf of Mexico during the initial few years when compared to other regions in the U.S. Typically, 50% of the reserves of properties in the Gulf of Mexico are depleted within three to four years with natural gas wells having a higher rate of depletion than oil wells. Due to high initial production rates, production of reserves from reservoirs in the Gulf of Mexico generally decline more rapidly than from other producing reservoirs. The vast majority of our existing operations are in the Gulf of Mexico. As a result, our reserve replacement needs from new prospects may be greater than those of other oil and gas companies with longer-life reserves in other producing areas. Also, our expected revenues and return on capital will depend on prices prevailing during these relatively short production periods. Our need to generate revenues to fund ongoing capital commitments or repay debt may limit our ability to slow or shut in production from producing wells during periods of low prices for oil and natural gas.

Our offshore operations involve special risks that could affect our operations adversely.

Offshore operations are subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties. In particular, we are not intending to put in place business interruption insurance due to its high cost. We therefore may not be able to rely on insurance coverage in the event of such natural phenomena.

TABLE OF CONTENTS

Deepwater operations present special risks that may adversely affect the cost and timing of reserve development.

Currently, we own interests in 6 undeveloped leases in the deepwater Gulf of Mexico and we have a non-operated interest in one developed lease. We may evaluate additional activity in the deepwater Gulf of Mexico in the future. Exploration for oil or natural gas in the deepwater of the Gulf of Mexico generally involves greater operational and financial risks than exploration on the shelf. Deepwater drilling generally requires more time and more advanced drilling technologies, involving a higher risk of technological failure and usually higher drilling costs. Deepwater wells often use subsea completion techniques with subsea trees tied back to host production facilities with flow lines. The installation of these subsea trees and flow lines requires substantial time and the use of advanced remote installation mechanics. These operations may encounter mechanical difficulties and equipment failures that could result in cost overruns. Furthermore, the deepwater operations generally lack the physical and oilfield service infrastructure present on the shelf. As a result, a considerable amount of time may elapse between a deepwater discovery and the marketing of the associated oil or natural gas, increasing both the financial and operational risk involved with these operations. Because of the lack and high cost of infrastructure, some reserve discoveries in the deepwater may never be produced economically.

Our insurance may not protect us against all of the operating risks to which our business is exposed.

We maintain insurance for some, but not all, of the potential risks and liabilities associated with our business. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. Due to market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance policies are economically unavailable or available only for reduced amounts of coverage. Consistent with industry practice, we are not fully insured against all risks, including high-cost business interruption insurance and drilling and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our financial condition and results of operations. Due to a number of catastrophic events like the terrorist attacks on September 11, 2001, Hurricanes Ivan, Katrina, Rita, Gustav and Ike, and the April 20, 2010 Deep Water Horizon incident, insurance underwriters increased insurance premiums for many of the coverages historically maintained and issued general notices of cancellation and significant changes for a wide variety of insurance coverages. The oil and natural gas industry suffered damage from Hurricanes Ivan, Katrina, Rita, Gustav and Ike. As a result, insurance costs have increased significantly from the costs that similarly situated participants in this industry have historically incurred. Insurers are requiring higher retention levels and limit the amount of insurance proceeds that are available after a major wind storm in the event that damages are incurred. If storm activity in the future is severe, insurance underwriters may no longer insure Gulf of Mexico assets against weather-related damage. In addition, we do not intend to put in place business interruption insurance due to its high cost. If an accident or other event resulting in damage to our operations, including severe weather, terrorist acts, war, civil disturbances, pollution or environmental damage, occurs and is not fully covered by insurance or a recoverable indemnity from a vendor, it could adversely affect our financial condition and results of operations. Moreover, we may not be able to maintain adequate insurance in the future at rates we consider reasonable or be able to obtain insurance against certain risks.

Competition for oil and gas properties and prospects is intense and some of our competitors have larger financial, technical and personnel resources that could give them an advantage in evaluating and obtaining properties and

prospects.

We operate in a highly competitive environment for reviewing prospects, acquiring properties, marketing oil and gas and securing trained personnel. Many of our competitors are major or independent oil and gas companies that possess and employ financial resources that allow them to obtain substantially greater technical and personnel resources than ours. We actively compete with other companies when acquiring new leases or oil and gas properties. For example, new leases acquired from the BOEM are acquired through a sealed bid process and are generally awarded to the highest bidder. These additional resources can be particularly important in reviewing prospects and purchasing properties. Competitors may be able to evaluate, bid for

TABLE OF CONTENTS

and purchase a greater number of properties and prospects than our financial or personnel resources permit. Competitors may also be able to pay more for productive oil and gas properties and exploratory prospects than we are able or willing to pay. Further, our competitors may be able to expend greater resources on the existing and changing technologies that we believe will impact attaining success in the industry. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated reserves.

This Transition Report contains estimates of our future net cash flows from our proved reserves. We base the estimated discounted future net cash flows from our proved reserves on average prices for the preceding twelve-month period and costs in effect on the day of the estimate. However, actual future net cash flows from our natural gas and oil properties will be affected by factors such as:

- the volume, pricing and duration of our natural gas and oil hedging contracts;
- supply of and demand for natural gas and oil;
- actual prices we receive for natural gas and oil;
- our actual operating costs in producing natural gas and oil;
- the amount and timing of our capital expenditures and decommissioning costs;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute exploration and exploitation plans on a timely basis and within budget, and consequently could adversely affect our anticipated cash flow.

We utilize third-party services to maximize the efficiency of our organization. The cost of oil field services may increase or decrease depending on the demand for services by other oil and gas companies. There is no assurance that we will be able to contract for such services on a timely basis or that the cost of such services will remain at a satisfactory or affordable level. Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our exploitation and exploration operations, which could have a material adverse effect on our business, financial condition or results of operations.

Market conditions or transportation impediments may hinder access to oil and gas markets, delay production or increase our costs.

Market conditions, the unavailability of satisfactory oil and natural gas transportation or the remote location of our drilling operations may hinder our access to oil and natural gas markets or delay production. The availability of a ready market for oil and gas production depends on a number of factors, including the demand for and supply of oil and gas and the proximity of reserves to pipelines or trucking and terminal facilities. In deepwater operations, market access depends on the proximity of and our ability to tie into existing production platforms owned or operated by others and the ability to negotiate commercially satisfactory arrangements with the owners or operators. We may be required to shut in wells or delay initial production for lack of a market or because of inadequacy or unavailability of pipeline or gathering system

22

TABLE OF CONTENTS

capacity. Restrictions on our ability to sell our oil and natural gas may have several other adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possible loss of a lease due to lack of production. In the event that we encounter restrictions in our ability to tie our production to a gathering system, we may face considerable delays from the initial discovery of a reservoir to the actual production of the oil and gas and realization of revenues. In some cases, our wells may be tied back to platforms owned by parties with no economic interests in these wells. There can be no assurance that owners of such platforms will continue to operate the platforms. If the owners cease to operate the platforms or their processing equipment, we may be required to shut in the associated wells, which could adversely affect our results of operations.

We are not the operator on all of our properties and therefore are not in a position to control the timing of development efforts, the associated costs, or the rate of production of the reserves on such properties.

As we carry out our planned drilling program, we will not serve as operator of all planned wells. We currently operate approximately 95% of our proved reserves (including approximately 20% attributable to the South Pass 49 field operated by Energy XXI). As a result, we may have limited ability to exercise influence over the operations of some non-operated properties or their associated costs. Dependence on the operator and other working interest owners for these projects, and limited ability to influence operations and associated costs could prevent the realization of targeted returns on capital in drilling or acquisition activities. The success and timing of development and exploitation activities on properties operated by others depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;
- the operator s expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of the reserves.

Each of these factors, including others, could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

We are exposed to trade credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our vendors, customers and by counterparties to our price risk management arrangements. Some of our vendors, customers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Many of our vendors, customers and counterparties finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. From time to time, the availability of credit is more restrictive. Additionally, many of our vendors , customers and counterparties equity values have substantially declined. The combination of reduction of cash flow resulting from declines in commodity prices and the lack of availability of debt or equity financing may result in a significant reduction in our vendors, customers and counterparties liquidity and ability to make payments or perform on their obligations to us. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our vendors, customers and/or counterparties could reduce our cash flows.

TABLE OF CONTENTS

Unanticipated decommissioning costs could materially adversely affect our future financial position and results of operations.

We may become responsible for unanticipated costs associated with abandoning and reclaiming wells, facilities and pipelines. Abandonment and reclamation of facilities and the costs associated therewith is often referred to as decommissioning. Should decommissioning be required that is not presently anticipated or the decommissioning be accelerated, such as can happen after a hurricane, such costs may exceed the value of reserves remaining at any particular time. We may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy such decommissioning costs could have a material adverse effect on our financial position and results of operations.

Lower oil and gas prices and other factors may result in ceiling test write-downs and other impairments of our asset carrying values.

Under the full cost method of accounting, we are required to perform each quarter, a ceiling test that determines a limit on the book value of our oil and gas properties. If the net capitalized cost of proved oil and gas properties, net of related deferred income taxes, plus the cost of unevaluated oil and gas properties, exceeds the present value of estimated future net cash flows discounted at 10%, net of related tax effects, plus the cost of unevaluated oil and gas properties, the excess is charged to expense and reflected as additional accumulated depreciation, depletion and amortization. As of the reported balance sheet date, capitalized costs of an oil and gas producing company may not exceed the full cost limitation calculated under the above described rule based on the average previous twelve-month prices for oil and natural gas. However, if prior to the balance sheet date, we enter into certain hedging arrangements for a portion of our future natural gas and oil production, thereby enabling us to receive future cash flows that are higher than the estimated future cash flows indicated, these higher hedged prices are used if they qualify as cash flow hedges.

Write-downs may be required in the full cost ceiling and goodwill recorded in connection with our oil and natural gas properties acquisition if oil and natural gas prices decline, unproved property values decrease, estimated proved reserve volumes are revised downward or the net capitalized cost of proved oil and gas properties otherwise exceeds the present value of estimated future net cash flows.

Our success depends on dedicated and skillful management and staff, whose departure could disrupt our business operations.

Our success depends on our ability to retain and attract experienced engineers, geoscientists and other professional staff. We depend to a large extent on the efforts, technical expertise and continued employment of these personnel and members of our management team. If a significant number of them resign or become unable to continue in their present role and if they are not adequately replaced, our business operations could be adversely affected.

Additionally, if John D. Schiller, Jr. ceases to be the chief executive officer of Energy XXI (except as a result of his death or disability) and a reasonably acceptable successor is not appointed, the lenders of our revolving credit facility could declare amounts outstanding thereunder immediately due and payable. Such an event could have a material adverse effect on our business and operations.

Cyber incidents could result in information theft, data corruption, operational disruption, and/or financial loss.

The oil and gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, conduct reservoir modeling and reserves estimation, and for compliance reporting. The use of mobile communication devices has increased rapidly. Industrial control systems such as SCADA (supervisory control and data acquisition) now control large scale processes that can include multiple sites and long distances, such as power generation and transmission, communications and oil and gas pipelines.

TABLE OF CONTENTS

We depend on digital technology, including information systems and related infrastructure, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimated quantities of oil and gas reserves and for many other activities related to our business. Our business partners, including vendors, service providers, purchasers of our production, and financial institutions, are also dependent on digital technology. The complexity of the technologies needed to extract oil and gas in increasingly difficult physical environments, such as ultra-deep trend, and global competition for oil and gas resources make certain information more attractive to thieves.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. Certain countries, including China, Russia and Iran, are believed to possess cyber warfare capabilities and are credited with attacks on American companies and government agencies. SCADA-based systems are potentially more vulnerable to cyber-attacks due to the increased number of connections with office networks and the internet.

Our technologies, systems, networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations in the following ways, among others:

unauthorized access to seismic data, reserves information or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;
data corruption, communication interruption, or other operational disruption during drilling activities could result in a dry hole cost or even drilling incidents;
data corruption or operational disruption of production infrastructure could result in loss of production, or accidental discharge;
a cyber-attack on a vendor or service provider could result in supply chain disruptions which could delay or halt one of our major development projects, effectively delaying the start of cash flows from the project;
a cyber-attack on a third party gathering or pipeline service provider could prevent us from marketing our production, resulting in a loss of revenues;
a cyber-attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;
a cyber-attack which halts activities at a power generation facility or refinery using natural gas as feed stock could have a significant impact on the natural gas market, resulting in reduced demand for our production, lower natural gas prices, and reduced revenues;
a cyber-attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;
a deliberate corruption of our financial or operational data could result in events of non-compliance which could lead to regulatory fines or penalties; and
business interruptions could result in expensive remediation efforts, distraction of management, and damage to our reputation.

TABLE OF CONTENTS

Although to date we have not experienced any losses relating to cyber-attacks, there can be no assurance that we will not suffer such losses in the future. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Risks Related to Our Risk Management Activities

If we place hedges on future production and encounter difficulties meeting that production, we may not realize the originally anticipated cash flows.

Our assets consist of a mix of reserves, with some being developed while others are undeveloped. To the extent that we sell the production of these reserves on a forward-looking basis but do not realize that anticipated level of production, our cash flow may be adversely affected if energy prices rise above the prices for the forward-looking sales. In this case, we would be required to make payments to the purchaser of the forward-looking sale equal to the difference between the current commodity price and that in the sales contract multiplied by the physical volume of the shortfall. There is the risk that production estimates could be inaccurate or that storms or other unanticipated problems could cause the production to be less than the amount anticipated, causing us to make payments to the purchasers pursuant to the terms of the hedging contracts.

Our price risk management activities could result in financial losses or could reduce our income, which may adversely affect our cash flows.

We enter into derivative contracts to reduce the impact of natural gas and oil price volatility on our cash flow from operations. Currently, we use a combination of natural gas and crude oil put, swap and collar arrangements to mitigate the volatility of future natural gas and oil prices received on our production.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative contracts for such period. If the actual amount of production is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount of production is lower than the notional amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial decrease in our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, our price risk management activities are subject to the following risks:

- a counterparty may not perform its obligation under the applicable derivative instrument;
- production is less than expected;
- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and
- the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures.

Risks Related to Our Acquisition Strategy

We may be unable to successfully integrate the operations of the properties or businesses we acquire.

Integration of the operations of the properties we acquire with our existing business is a complex, time-consuming and costly process. Failure to successfully integrate the acquired businesses and operations in a timely manner may have a material adverse effect on our business, financial condition, results of operations and cash flows. The difficulties of combining the acquired operations include, among other things:

- operating a larger organization;
- coordinating geographically disparate organizations, systems and facilities;
- integrating corporate, technological and administrative functions;

TABLE OF CONTENTS

- diverting management s attention from other business concerns;
- diverting financial resources away from existing operations;
- increasing our indebtedness; and
- incurring potential environmental or regulatory liabilities and title problems.

The process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any business activities are interrupted as a result of the integration process, our business could suffer.

We may not realize all of the anticipated benefits from our acquisitions.

We may not realize all of the anticipated benefits from our current and future acquisitions, such as increased earnings, cost savings and revenue enhancements, for various reasons, including difficulties integrating operations and personnel, higher than expected acquisition and operating costs or other difficulties, unknown liabilities, inaccurate reserve estimates and fluctuations in market prices.

If we are unable to effectively manage the commodity price risk of our production if energy prices fall, we may not realize the anticipated cash flows from our acquisitions.

Compared to some other participants in the oil and gas industry, we are a relatively small company with modest resources. Therefore, there is the possibility that we may be unable to find counterparties willing to enter into derivative arrangements with us or be required to either purchase relatively expensive put options, or commit to deliver future production, to manage the commodity price risk of our future production. To the extent that we commit to deliver future production, we may be forced to make cash deposits available to counterparties as they mark to market these financial hedges. Proposed changes in regulations affecting derivatives may further limit or raise the cost, or increase the credit support required to hedge. This funding requirement may limit the level of commodity price risk management that we are prudently able to complete. In addition, we are unlikely to hedge undeveloped reserves to the same extent that we hedge the anticipated production from proved developed reserves. If we fail to manage the commodity price risk of our production and energy prices fall, we may not be able to realize the cash flows from our assets that are currently anticipated even if we are successful in increasing the production and ultimate recovery of reserves.

The properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the acquired properties or obtain protection from sellers against such liabilities.

Our business strategy includes a continuing acquisition program, which may include acquisitions of exploration and production companies, producing properties and undeveloped leasehold interests. The successful acquisition of oil and natural gas properties requires assessments of many factors that are inherently inexact and may be inaccurate, including the following:

- acceptable prices for available properties;
- amounts of recoverable reserves;
- estimates of future oil and natural gas prices;

- estimates of future exploratory, development and operating costs;
- estimates of the costs and timing of plugging and abandonment; and
- estimates of potential environmental and other liabilities.

Our assessment of the acquired properties will not reveal all existing or potential problems nor will it permit us to become familiar enough with the properties to fully assess their capabilities and deficiencies. In the course of our due diligence, we historically have not physically inspected every well, platform or pipeline. Even if we had physically inspected each of these, our inspections may not have revealed structural and environmental problems, such as pipeline corrosion or groundwater contamination. We may not be able to obtain contractual indemnities from the seller for liabilities associated with such risks. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations. If an acquired property does not perform as originally estimated, we may have an impairment, which could have a material adverse effect on our financial position and results of operations.

Risks Related to Our Indebtedness and Access to Capital and Financing

Our level of indebtedness may limit our ability to borrow additional funds or capitalize on acquisition or other business opportunities.

As of June 30, 2014, we had total indebtedness of $1,026 million. Our leverage and the current and future restrictions contained in the agreements governing our indebtedness may reduce our ability to incur additional indebtedness, engage in certain transactions or capitalize on acquisition or other business opportunities. Our indebtedness and other financial obligations and restrictions could have financial consequences. For example, they could:

impair our ability to obtain additional financing in the future for capital expenditures, potential acquisitions, general business activities or other purposes;
increase our vulnerability to general adverse economic and industry conditions;
result in higher interest expense in the event of increases in interest rates since some of our debt is at variable rates of interest;
have a material adverse effect if we fail to comply with financial and restrictive covenants in any of our debt agreements, including an event of default if such event is not cured or waived;
require us to dedicate a substantial portion of future cash flow to payments of our indebtedness and other financial obligations, thereby reducing the availability of our cash flow to fund working capital, capital expenditures and other general corporate requirements;
limit our flexibility in planning for, or reacting to, changes in our business and industry; and
place us at a competitive disadvantage to those who have proportionately less debt.

If we are unable to meet future debt service obligations and other financial obligations, we could be forced to restructure or refinance our indebtedness and other financial transactions, seek additional equity or sell assets. We may then be unable to obtain such financing or capital or sell assets on satisfactory terms, if at all.

We and our subsidiaries may be able to incur substantially more debt. This could further increase our leverage and attendant risks.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future. The terms of the indentures governing our senior notes and our revolving credit facility do not fully prohibit us or our subsidiaries from doing so. At June 30, 2014, we and our subsidiaries collectively had $475 million of secured indebtedness and $510 million aggregate principal amount of our 8.25% senior notes due 2018 ($551 million carrying value) (the 8.25% Senior Notes). If new debt or liabilities are added to our current debt level, the related risks that we now face could increase.

To service our indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control.

Our ability to make payments on and to refinance our indebtedness and to fund planned capital expenditures and development and exploration efforts will depend on our ability to generate cash in the future. Our future operating performance and financial results will be subject, in part, to factors beyond our control, including interest rates and general economic, financial and business conditions. We cannot assure that our business will generate sufficient cash flow from operations or that future borrowing or other facilities will be available to us in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs.

TABLE OF CONTENTS

If we are unable to generate sufficient cash flow to service our debt, we may be required to:

- refinance all or a portion of our debt;
- obtain additional financing;
- sell some of our assets or operations;
- reduce or delay capital expenditures, research and development efforts and acquisitions; or
- revise or delay our strategic plans.

If we are required to take any of these actions, it could have a material adverse effect on our business, financial condition and results of operations. In addition, we cannot assure that we would be able to take any of these actions, that these actions would enable us to continue to satisfy our capital requirements or that these actions would be permitted under the terms of our various debt instruments.

The covenants in the indentures governing our senior notes and our revolving credit facility impose restrictions that may limit our ability and the ability of our subsidiaries to take certain actions. Our failure to comply with these covenants could result in the acceleration of our outstanding indebtedness.

The indentures governing our 8.25% Senior Notes and our revolving credit facility contain various covenants that limit our ability and the ability of our subsidiaries to, among other things:

- incur certain payment obligations;
- incur indebtedness and issue preferred stock; and
- sell or otherwise dispose of assets, including capital stock of subsidiaries.

The existence of these covenants may prevent or delay us from pursuing business opportunities that we believe would otherwise benefit us.

In addition, if we breach any of these covenants, a default could occur. A default, if not waived, would entitle certain of our debt holders to declare all amounts borrowed under the breached indenture to become immediately due and payable, which could also cause the acceleration of obligations under certain other agreements and the termination of our credit facility. We cannot assure you that we will be granted waivers or amendments to these agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on acceptable terms or at all should we seek to do so. In the event of acceleration of our outstanding indebtedness, we cannot assure that we would be able to repay our debt or obtain new financing to refinance our debt. Even if new financing was made available to us, it may not be on terms acceptable to us.

We expect to have substantial capital requirements, and we may be unable to obtain needed financing on satisfactory terms.

We expect to make substantial capital expenditures for the acquisition, development, production, exploration and abandonment of oil and gas properties. Our capital requirements depend on numerous factors and we cannot predict accurately the timing and amount of our capital requirements. We intend to primarily finance our capital expenditures through cash flow from operations. However, if our capital requirements vary materially from those provided for in our current projections, we may require additional financing. A decrease in expected revenues or an adverse change in market conditions could make obtaining this financing economically unattractive or impossible.

The cost of raising money in the debt and equity capital markets may increase substantially while the availability of funds from those markets may diminish significantly. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets may increase as lenders and institutional investors could increase interest rates, impose tighter lending standards, refuse to refinance existing debt at maturity at all or on terms similar to our current debt and, in some cases, cease to provide funding to borrowers.

We expect to have substantial capital requirements, and we may be unable toobtain needed financing on satisfacto

TABLE OF CONTENTS

An increase in our indebtedness, as well as the credit market and debt and equity capital market conditions discussed above could negatively impact our ability to remain in compliance with the financial covenants under our revolving credit facility which could have a material adverse effect on our financial condition, results of operations and cash flows. If we are unable to finance our growth as expected, we could be required to seek alternative financing, the terms of which may be less favorable to us, or not pursue growth opportunities.

Without additional capital resources, we may be forced to limit or defer our planned natural gas and oil exploration and development program and this will adversely affect the recoverability and ultimate value of our natural gas and oil properties, in turn negatively affecting our business, financial condition and results of operations. We may also be unable to obtain sufficient credit capacity with counterparties to finance the hedging of our future crude oil and natural gas production which may limit our ability to manage price risk. As a result, we may lack the capital necessary to complete potential acquisitions, obtain credit necessary to enter into derivative contracts to hedge our future crude oil and natural gas production or to capitalize on other business opportunities.

The borrowing base under our revolving credit facility may be reduced in the future if commodity prices decline, which will limit our available funding for exploration and development.

As of June 30, 2014, our borrowing base under our revolving credit facility was $475 million of the total $1.5 billion borrowing base of EGC, both of which were reconfirmed as part of the full redetermination on September 5, 2014. As of June 30, 2014, we had borrowed the full $475 million. Our borrowing base is redetermined semi-annually by our lenders in their sole discretion. The lenders will redetermine the borrowing base based on an engineering report with respect to our natural gas and oil reserves, which will take into account the prevailing natural gas and oil prices at such time. If oil and natural gas commodity prices deteriorate, the revised borrowing base under our revolving credit facility may be reduced. As we have borrowed all available capacity under our current borrowing base, if our borrowing base were adjusted downward, we would be required to pay down amounts outstanding under our revolving credit facility to reduce our level of borrowing. If funding is not available from internally generated cash flow, additional borrowings from or investments by EGC in the Company when needed, or is available only on unfavorable terms, it could adversely affect our exploration and development plans as currently anticipated and our ability to make new acquisitions, each of which could have a material adverse effect on our production, revenues and results of operations.

The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our revolving credit facility. Any increase in the borrowing base requires the consent of all the lenders. If the borrowing base is reduced or maintained, the new borrowing base is subject to approval by banks holding not less than 67% of the lending commitments under our revolving credit facility, and the final borrowing base may be lower than the level recommended by the agent for the bank group.

Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other natural gas and oil properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under our revolving credit facility.

Risks Related to Environmental and Other Regulations

Our operations are subject to environmental and other government laws and regulations that are costly and could potentially subject us to substantial liabilities.

As described in more detail below, our business activities are subject to regulation by multiple federal, state and local governmental agencies. Our historical and projected operating costs reflect the recurring costs resulting from compliance with these regulations, and we do not anticipate material expenditures in excess of these amounts in the absence of future acquisitions or changes in regulation, or discovery of existing but unknown compliance issues. Additional proposals and proceedings that affect the oil and gas industries are regularly considered by Congress, the states, regulatory commissions and agencies, and the courts. We cannot predict when or whether any such proposals may become effective or the magnitude of the impact changes in laws and regulations may have on our business; however, additions or enhancements to the regulatory burden on our industry generally increase the cost of doing business and affect our profitability.

Our oil and gas exploration, production, and related operations are subject to extensive rules and regulations promulgated by federal, state, and local agencies. Failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the oil and gas industry increases our cost of doing business and affects our profitability. Because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws.

All of the jurisdictions in which we operate generally require permits for drilling operations, drilling bonds, and reports concerning operations and impose other requirements relating to the exploration and production of oil and gas. Such jurisdictions also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells and the spacing, plugging and abandonment of such wells. The statutes and regulations of certain jurisdictions also limit the rate at which oil and gas can be produced from our properties.

FERC regulates interstate natural gas transportation rates and terms of service, which affect the marketing of gas we produce, as well as the revenues we receive for sales of such production. Since the mid-1980s, FERC has issued various orders that have significantly altered the marketing and transportation of gas. These orders resulted in a fundamental restructuring of interstate pipeline sales and transportation services, including the unbundling by interstate pipelines of the sales, transportation, storage and other components of the city-gate sales services such pipelines previously performed. These FERC actions were designed to increase competition within all phases of the gas industry. The interstate regulatory framework may enhance our ability to market and transport our gas, although it may also subject us to greater competition and to the more restrictive pipeline imbalance tolerances and greater associated penalties for violation of such tolerances.

Our sales of oil and natural gas liquids are not presently regulated and are made at market prices. The price we receive from the sale of those products is affected by the cost of transporting the products to market. FERC has implemented regulations establishing an indexing methodology for interstate transportation rates for oil pipelines, which, generally, would index such rate to inflation, subject to certain conditions and limitations. We are not able to predict with any certainty what effect, if any, these regulations will have on us, but, other factors being equal, the regulations may, over time, tend to increase transportation costs which may have the effect of reducing wellhead prices for oil and natural gas liquids.

Under the EPAct 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. While our operations have not been regulated by FERC under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional entities to FERC annual reporting and daily scheduled flow and capacity posting requirements, as described more fully in Item 1 above. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability.

Although FERC has not made any formal determinations with respect to any of our facilities, we believe that our natural gas gathering pipelines meet the traditional tests that FERC has used to determine if a pipeline is a gathering pipeline and are therefore not subject to FERC s jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of substantial litigation, however, and, over time, FERC s policy for determining which facilities it regulates has changed. In addition, the distinction between FERC-regulated transmission facilities, on the one hand, and gathering facilities, on the other, is a fact-based determination made by FERC on a case-by-case basis. If FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the NGA and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by FERC under the NGA or the Natural Gas Policy Act of 1978 (NGPA). Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided

31

services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the rate established by FERC.

State regulation of gathering facilities includes safety, environmental and, in some circumstances, nondiscriminatory take requirements and in some instances complaint-based rate regulation. Our gathering operations may also be subject to state ratable take and common purchaser statutes, designed to prohibit discrimination in favor of one producer over another or one source of supply over another. State and local regulation may cause us to incur additional costs or limit our operations and can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies.

Our oil and gas operations are subject to stringent laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from operations.

Failure to comply with these laws and regulations may result in:

- the imposition of administrative, civil and/or criminal penalties;
- incurring investigatory or remedial obligations; and
- the imposition of injunctive relief, which could limit or restrict our operations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Although we intend to be in compliance in all material respects with all applicable environmental laws and regulations, we cannot assure shareholders that we will be able to comply with existing or new regulations. In addition, the risk of accidental spills, leakages or other circumstances could expose us to extensive liability.

Under certain environmental laws that impose strict, joint and several liability, we could be held liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination, and regardless of whether current or prior operations were conducted in compliance with all applicable laws and consistent with accepted standards of practice at the time those actions were taken. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations. Such liabilities can be significant, and if imposed could have a material adverse effect on our financial condition or results of operations.

We are unable to predict the effect of additional environmental laws and regulations that may be adopted in the future, including whether any such laws or regulations would materially adversely increase our cost of doing business or affect operations in any area.

TABLE OF CONTENTS

Rate regulation may not allow us to recover the full amount of increases in our costs.

We have ownership interests in oil pipelines that are subject to regulation by FERC. Rates for service on our system are set using FERC s price indexing methodology. The indexing method currently allows a pipeline to increase its rates by a percentage factor equal to the change in the producer price index for finished goods plus 2.65 percent. When the index falls, we are required to reduce rates if they exceed the new maximum allowable rate. In addition, changes in the index might not be large enough to fully reflect actual increases in our costs.

FERC s indexing methodology is subject to review every five years. The current or any revised indexing formula could hamper our ability to recover our costs because: (1) the indexing methodology is tied to an inflation index; (2) it is not based on pipeline-specific costs; and (3) it could be reduced in comparison to the current formula. Any of the foregoing would adversely affect our revenues and cash flow. FERC could limit our pipeline s ability to set rates based on its costs, order our pipelines to reduce rates, require the payment of refunds or reparations to shippers, or any or all of these actions, which could adversely affect our financial position, cash flows, and results of operations. If FERC s ratemaking methodology changes, the new methodology could also result in tariffs that generate lower revenues and cash flow.

Based on the way our oil pipelines are operated, we believe that the only transportation on our pipelines that is subject to the jurisdiction of FERC is the transportation specified in the tariff we have on file with FERC. We cannot guarantee that the jurisdictional status of transportation on our pipelines and related facilities will remain unchanged, however. Should circumstances change, then currently non-jurisdictional transportation could be found to be FERC-jurisdictional. In that case, FERC s ratemaking methodologies may limit our ability to set rates based on our actual costs, may delay the use of rates that reflect increased costs, and may subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect our business, results of operations and financial condition.

If our tariff rates are successfully challenged, we could be required to reduce our tariff rates, which would reduce our revenues.

Shippers on our pipelines are free to challenge, or to cause other parties to challenge or assist others in challenging, our existing or proposed tariff rates. If any party successfully challenges our tariff rates, the effect would be to reduce revenues.

New regulatory requirements and permitting procedures recently imposed by the BSEE could significantly delay our ability to obtain permits to drill new wells in offshore waters.

Subsequent to the April 2010 Deepwater Horizon incident in the Gulf of Mexico, federal authorities have pursued a series of regulatory initiatives to address the direct impact of that incident and to prevent similar incidents in the future. The federal government, acting through the U.S. Department of the Interior (DOI) and its implementing agencies that have since evolved into the present day BOEM and the BSEE, have issued various rules, Notices to Lessees and Operators (NTLs), and temporary drilling moratoria imposing new regulatory requirements and environmental and safety measures upon exploration, development and production operators in the Gulf of Mexico. These new regulatory requirements include the following:

The Environmental NTL, which imposes new and more stringent requirements for documenting the environmental impacts potentially associated with the drilling of a new offshore well and significantly increases oil spill response requirements.

The Compliance and Review NTL, which imposes requirements for operators to secure independent reviews of well design, construction and flow intervention processes, and also requires certifications of compliance from senior corporate officers.

The Drilling Safety Rule, which prescribes tighter cementing and casing practices, imposes standards for the use of drilling fluids to maintain well bore integrity and stiffens oversight requirements relating to blowout preventers and their components, including shear and pipe rams.

The Workplace Safety Rule, which requires operators to have a comprehensive safety and environmental management system in order to reduce human and organizational errors as root causes of work-related accidents and offshore spills.

New regulatory requirements and permitting procedures recently imposed bythe BSEE could significantly delay our

These regulatory initiatives may serve to effectively slow down the pace of drilling and production operations in the Gulf of Mexico due to adjustments in operating procedures and certification practices as well as increased lead times to obtain exploration and production plan reviews, develop drilling applications, and apply for and receive new well permits. The new rules also increase the cost of preparing each permit application and will increase the cost of each new well, particularly for wells drilled in deeper waters on the OCS. The Workplace Safety Rule also has the potential to increase the cost of operating existing wells. In addition, we could become subject to fines, penalties or orders requiring us to modify or suspend our operations in the Gulf of Mexico if we fail to comply with these requirements. Moreover, if oil spill incidents similar to the April 2010 Deepwater Horizon incident were to occur in the future in areas where we conduct operations, the United States or other countries could elect to issue directives to temporarily cease drilling activities and, in any event, may from time to time issue safety and environmental regulatory initiatives regarding offshore oil and gas exploration and development activities, which any one or more of such events could have a material adverse effect on our volume of business, our financial position, our results of operations, and liquidity.

Our estimates of future asset retirement obligations may vary significantly from period to period and are especially significant because our operations include the U.S. Gulf of Mexico.

We are required to record a liability for the discounted present value of our asset retirement obligations to plug and abandon inactive, non-producing wells, to remove inactive or damaged platforms, facilities and equipment, and to restore the land or seabed at the end of oil and natural gas production operations. These costs are typically considerably more expensive for offshore operations as compared to most land-based operations due to increased regulatory scrutiny and the logistical issues associated with working in waters of various depths. Estimating future restoration and removal costs in the U.S. Gulf of Mexico is especially difficult because most of the removal obligations are many years in the future, regulatory requirements are subject to change or more restrictive interpretation, and asset removal technologies are constantly evolving, which may result in additional or increased costs. As a result, we may make significant increases or decreases to our estimated asset retirement obligations in future periods. For example, because we operate in the U.S. Gulf of Mexico, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes. The estimated cost to plug and abandon a well or dismantle a platform can change dramatically if the host platform from which the work was anticipated to be performed is damaged or toppled rather than structurally intact. Accordingly, our estimate of future asset retirement obligations could differ dramatically from what we may ultimately incur as a result of damage from a hurricane.

Moreover, the timing for pursuing restoration and removal activities has accelerated for operators in the U.S. Gulf of Mexico following the DOI s issuance of an NTL, effective October 2010, that established a more stringent regimen for the timely decommissioning of what is known as idle iron wells, platforms and pipelines that are no longer producing or serving exploration or support functions with respect to an operator s lease in the U.S. Gulf of Mexico. Historically, many oil and natural gas producers in the Gulf of Mexico have delayed the plugging, abandoning or removal of idle iron until they met the final decommissioning regulatory requirement, which has been established as being within one year after the lease expires or terminates, a time period that sometimes is years after use of the idle iron has been discontinued. The idle iron NTL establishes new triggers for commencing decommissioning activities any well that has not been used during the past five years for exploration or production on active leases and is no longer capable of producing in paying quantities must be permanently plugged or temporarily abandoned within three years time. Plugging or abandonment of wells may be delayed by two years if all of such wells hydrocarbon and sulfur zones are appropriately isolated. Similarly, platforms or other facilities no longer useful for operations must be removed within five years of the cessation of operations. The triggering of these plugging, abandonment and removal activities under what may be viewed as an accelerated schedule in comparison to historical decommissioning efforts may serve to increase, perhaps materially, our future plugging, abandonment and removal costs, which may translate into a need to increase our estimate of future asset retirement obligations required to meet such increased costs. Moreover, as a result of the implementation of this NTL, there is expected to be increased demand for salvage contractors and equipment operating in the U.S. Gulf of Mexico, resulting in increased estimates of plugging, abandonment and removal costs and associated increases in operators asset retirement obligations.

34

TABLE OF CONTENTS

Lastly, it is expected that a new NTL related to the requirements for an exemption from supplemental bonding will be issued in late 2014 or early 2015 which is expected to impact the eligibility to receive a supplemental bonding waiver.

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

FERC, the FTC and the CFTC hold statutory authority to regulate certain segments of the physical and futures energy commodities markets relevant to our business. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil and natural gas, and any hedging activities related to these commodities, we are required to observe and comply with these anti-fraud and anti-manipulation regulations. Failure to comply with such regulations, as interpreted and enforced, could materially and adversely affect our financial condition or results of operations.

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

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other greenhouse gases 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 greenhouse gases under existing provisions of the federal Clean Air Act (CAA). Among the EPA s rules regulating greenhouse gas emissions under the CAA, one requires a reduction in emissions of greenhouse gases from motor vehicles and another regulates emissions of greenhouse gases from certain large stationary sources. The EPA has also adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified greenhouse gas emission sources in the United States, including petroleum refineries and certain onshore oil and natural gas production facilities.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases 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 and results of operations.

The adoption of financial reform legislation by Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us that participate in that market. This legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), was signed into law by President Obama on July 21, 2010 and requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Dodd-Frank Act, the CFTC has issued final regulations to set position limits for certain

35

TABLE OF CONTENTS

futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require certain counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The final rules will be phased in over time according to a specified schedule which is dependent on the finalization of certain other rules to be promulgated jointly by the CFTC and the SEC. The Dodd-Frank Act and any new regulations could increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize 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 adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil, natural gas liquids and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas liquids and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

We and our subsidiaries may need to obtain bonds or other surety in order to maintain compliance with those regulations promulgated by the U.S. Bureau of Ocean Energy Management, which, if required, could be costly and reduce borrowings available under our bank credit facility.

To cover the various obligations of lessees on the OCS of the Gulf of Mexico, such as the cost to plug and abandon wells and decommission and remove platforms and pipelines at the end of production, the BOEM generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. As a result of the recent bankruptcy of ATP Oil and Gas, the BOEM has indicated that it may review the estimated cost of future plugging, abandonment, decommissioning and removal obligations of other OCS operators and may increase the amount of financial assurance required with respect to these obligations. While we believe that we are currently exempt from the supplemental bonding requirements of the BOEM, the BOEM could re-evaluate our plugging obligations and increase them which could cause us to lose our exemption. The cost of these bonds or other surety could be substantial and there is no assurance that bonds or other surety could be obtained in all cases. In addition, we may be required to provide letters of credit to support the issuance of these bonds or other surety. Such letter of credit would likely be issued under our credit facility and would reduce the amount of borrowings available under such facility in the amount of any such letter of credit obligations. The cost of compliance with these supplemental bonding requirements could materially and adversely affect our financial condition, cash flows and results of operations.

If we are unable to acquire or renew permits and approvals required for operations, we may be forced to suspend or cease operations altogether.

The construction and operation of energy projects require numerous permits and approvals from governmental agencies. In addition, many governmental agencies have increased regulatory oversight and permitting requirements in recent years. We may not be able to obtain all necessary permits and approvals or obtain them in a timely manner, and as a result our operations may be adversely affected. In addition, obtaining all necessary permits and approvals may necessitate substantial expenditures to comply with the requirements of these permits and approvals, future changes to these permits or approvals, or any adverse changes in the interpretation of existing permits and approvals, and these may create a risk of expensive delays or loss of value if a project is unable to proceed as planned due to changing requirements or local opposition.

TABLE OF CONTENTS

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

The Budget for Fiscal Year 2014 sent to Congress by President Obama on April 10, 2013, among other proposed legislation, contains recommendations that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include (1) the repeal of the percentage depletion allowance for oil and natural gas properties, (2) the elimination of current deductions for intangible drilling and development costs, (3) the elimination of the deduction for certain domestic production activities, and (4) an extension of the amortization period for certain geological and geophysical expenditures. Several bills have been introduced in Congress that would implement these proposals. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such changes could have an adverse effect on our financial position, results of operations and cash flows.

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

None.

Item 2. ***Properties***

The information contained in Part I, Item 1, Business of this Transition Report is incorporated herein by reference.

Item 3. ***Legal Proceedings***

The information contained in Note 14, Commitments and Contingencies in the consolidated financial statements in Part II, Item 8 of this Transition Report is incorporated herein by reference.

Item 4. ***Mine Safety Disclosures***

Not applicable.

TABLE OF CONTENTS

PART II

Item 5. ***Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Following the effective date of the Merger, we became an indirect, wholly owned subsidiary of Energy XXI and there is no longer a trading market for EPL common stock. As a result of the Merger, our common stock was suspended from trading on June 4, 2014 and removed from listing and registration on the New York Stock Exchange (the NYSE) on July 15, 2014.

Prior to the Merger, our common stock was listed on the NYSE under the symbol EPL. The following table sets forth, for the periods indicated, the range of the high and low sales prices of our common stock as reported by the NYSE.

	High ($)	Low ($)
2012		
First Quarter	18.49	14.72
Second Quarter	17.53	14.56
Third Quarter	21.99	16.01
Fourth Quarter	23.28	19.31
2013		
First Quarter	29.18	22.53
Second Quarter	35.14	26.05
Third Quarter	38.32	28.75
Fourth Quarter	42.64	25.00
2014		
First Quarter	39.26	25.18
Second Quarter (through June 3, 2014)	39.31	36.85

On June 3, 2014, the last reported sales price of our common stock on the NYSE was $37.73 per share.

We have not paid cash dividends in the past on our common stock. The covenants in certain debt instruments to which we are a party, including the 8.25% senior notes due 2018 (the 8.25% Senior Notes) issued under an indenture dated February 14, 2011 (the 2011 Indenture), place certain restrictions and conditions on our ability to pay dividends. Any future cash dividends would depend on contractual limitations, future earnings, capital requirements, our financial condition and other factors determined by our board of directors.

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of June 30, 2014 with respect to compensation plans under which our equity securities are authorized for issuance.

Plan Category	Securities to be Issued upon Exercise of Outstanding	Weighted Average Exercise Price of Outstanding	Number of Securities Remaining Available for Future Issuance

	Options, Warrants and Rights[1]	Options, Warrants and Rights	Under Equity Compensation Plans[2]
Equity compensation plans approved by stockholders[3]		$	1,087,347

(1) As a result of the change of control in connection with the Merger, all outstanding options immediately vested and were deemed exercised and all restrictions associated with restricted share awards immediately lapsed.

38

TABLE OF CONTENTS

(2) These shares are available for future issuance under the 2009 Long Term Incentive Plan, as amended, in the form of options, appreciation rights, restricted shares, deferred shares, bonus stock and performance shares, units or restricted stock units.

(3) At our 2011 and 2013 annual meetings of stockholders, our stockholders approved increases in the number of shares authorized for issuance under the 2009 Long Term Incentive Plan from 1,237,000 shares to 3,574,000 shares.

See Note 13 Employee Benefit Plans of the consolidated financial statements in Part II, Item 8 of this Transition Report for further information regarding the material features of the above plan and the impact of the Merger on previously outstanding equity awards.

Item 6. ***Selected Financial Data***

Not applicable due to reduced disclosure format allowed for certain wholly-owned subsidiaries pursuant to General Instruction I(1)(a) and (b) of Form 10-K.

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

Overview

EPL Oil & Gas, Inc. (we, our, us, or the Company) was incorporated as a Delaware corporation on January 29, 19 We are an independent oil and natural gas exploration and production company. Our current operations are concentrated in the U.S. Gulf of Mexico shelf (the GoM shelf) focusing on state and federal waters offshore Louisiana, which we consider our core area. We have focused on acquiring and developing assets in this region, as it offers a balanced and expansive array of existing and prospective exploration, exploitation and development opportunities in both established productive horizons and deeper geologic formations. As of June 30, 2014, we had estimated proved reserves of 89.5 Mmboe, of which 68% were oil and 69% were proved developed. Of these proved developed reserves, 73% were oil reserves.

On June 3, 2014, Energy XXI (Bermuda) Limited, an exempted company under the laws of Bermuda (Energy XXI), Energy XXI Gulf Coast, Inc. (EGC), Clyde Merger Sub, Inc., a wholly owned subsidiary of EGC (Merger Sub), and EPL, completed the transactions contemplated by the Agreement and Plan of Merger, dated as of March 12, 2014 (as amended, the Merger Agreement), by and among Energy XXI, EGC, Merger Sub, and EPL, pursuant to which Merger Sub was merged with and into EPL with EPL continuing as the surviving corporation (the Merger). Pursuant to the Merger Agreement, at the effective time of the Merger (the Effective Time), the issued and outstanding shares of EPL common stock, par value $0.001 per share (EPL Common Stock), were converted, in the aggregate, into the right to receive merger consideration (the Merger Consideration) consisting of approximately 65% in cash and 35% in shares of common stock of Energy XXI, par value $0.005 per share (Energy XXI Common Stock).

The Merger resulted in EPL becoming an indirect, wholly owned subsidiary of Energy XXI. Therefore, in the preparation of our financial statements, we have applied pushdown accounting, based on guidance from the Securities and Exchange Commission (SEC). Pushdown accounting refers to the use of the acquiring entity s basis of accounting in the preparation of the acquired entity s financial statements. As a result, our separate financial statements reflect the new basis of accounting recorded by Energy XXI upon acquisition. As such, in accordance with GAAP, due to our new basis of accounting, our financial statements include a black line denoting that our financial statements covering periods prior to the date of the Merger are not comparable to our financial statements as of and subsequent to the date of the Merger. References to the Predecessor Company refer to reporting dates of the Company through June 3, 2014, reflecting results of operations and cash flows of the Company prior to the Merger on our historical accounting basis; subsequent thereto, the Company is referred to as the Successor Company, reflecting the impact of pushdown accounting and the results of operations and cash flows of the Company subsequent to the Merger.

Energy XXI follows the full cost method of accounting for its oil and gas producing activities, while we had historically followed the successful efforts method of accounting. Subsequent to the Merger, we converted our accounting method from successful efforts to the full cost method of accounting to be consistent with Energy XXI s method of accounting pursuant to SEC guidance, which requires a reporting entity that follows the full cost method to apply that method to all of its operations and to the operations of its subsidiaries. Under GAAP, a change in accounting method is generally required to be applied retroactively in order to provide comparable historical period information to users of financial statements. However, due to the new basis of accounting established as a result of the Merger transaction and pushdown accounting, our financial statements are no longer comparable to those of prior periods and we have applied the full cost method of accounting on a prospective basis from the date of the Merger.

Energy XXI has a fiscal year end of June 30, while we historically had a fiscal year end of December 31. Subsequent to the Merger, we changed our fiscal year end to June 30 to be consistent with Energy XXI. Therefore, these financial statements include audited statements of operations, cash flows and stockholders equity using the successful efforts method of accounting applied to the historical basis in our assets and liabilities for the five months and three days ended June 3, 2014 and audited statements of operations, cash flows and stockholders equity using the full cost method of accounting applied to EPL s new basis in its assets and liabilities established in the Merger transaction for the twenty-seven days ended June 30, 2014, with a black line between the periods denoting that they are not comparable.

Prior to the Merger, we used the successful efforts method of accounting for oil and natural gas producing activities. Costs to acquire mineral interests in oil and natural gas properties, to drill and complete exploratory wells with found proved reserves, and to drill and complete development wells were capitalized. Exploratory drilling costs were initially capitalized, but charged to expense if and when a well was determined not to have reserves in commercial quantities. Geological and geophysical costs were charged to expense as incurred. Leasehold acquisition costs were capitalized as unproved properties. If proved reserves were discovered on undeveloped leases, the related leasehold costs were transferred to proved properties and amortized using the units of production method. For individual unevaluated properties with capitalized costs below a threshold amount, we allocated capitalized costs to earnings generally over the primary lease terms. Properties that were subject to amortization and those with capitalized costs greater than the threshold amount were assessed for impairment periodically. Capitalized costs of producing oil and natural gas properties were depreciated and depleted by the units-of-production method.

Subsequent to the Merger, we adopted the full cost method of accounting for exploration and development activities. Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to property acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves.

Under the full cost method, oil and natural gas properties include costs that are excluded from costs being depleted or amortized. Costs excluded from depletion or amortization represent investments in unevaluated properties and include non-producing leasehold, geological and geophysical costs associated with leasehold or drilling interests and exploration drilling costs. We exclude these costs until the property has been evaluated. We also allocate a portion of our acquisition costs to unevaluated properties based on fair value. Costs are transferred to the full cost pool as the properties are evaluated or over the life of the reservoir.

2014 Acquisitions

On June 3, 2014 we acquired from Energy XXI GOM, LLC, a Delaware limited liability company and wholly-owned subsidiary of Energy XXI (Energy XXI GOM), the SP49 Interests for $230.0 million, subject to customary adjustments to reflect an economic effective date of June 1, 2014 (the SP49 Acquisition). We estimate that the proved reserves as of the June 1, 2014 economic effective date totaled approximately 11.3 Mmboe, of which 74% were oil and 73% were proved developed reserves. Prior to the SP49 Acquisition, we owned a 43.5% working interest in certain of these assets, and Energy XXI owned a 56.5% working interest in certain of these assets as well as 100% interest in additional assets in the field. As a result of the SP49 Acquisition, we have become the sole working interest owner of the South Pass 49 field. We financed the SP49 Acquisition with cash of approximately $135 million and a $95 million capital contribution from EGC.

40

TABLE OF CONTENTS

On January 15, 2014, we acquired from Nexen Petroleum Offshore U.S.A., Inc. (Nexen) 100% working interest of certain shallow-water central GoM shelf oil and natural gas assets for $70.4 million, subject to customary adjustments to reflect the September 1, 2013, economic effective date (the Nexen Acquisition). The assets we acquired comprise five leases in the Eugene Island 258/259 field (the EI Interests). Estimated proved reserves as of the September 1, 2013 effective date consisted of approximately 2.6 Mmboe of proved developed producing reserves, about 91% of which were oil. The Nexen Acquisition was financed with borrowings under the senior secured credit facility entered into on February 14, 2011 and amended and restated on October 31, 2012 with BMO Capital Markets, as lead arranger, and Bank of Montreal, as administrative agent and a lender, and the other lender parties thereto (as amended and restated, the Prior Senior Credit Facility) in place prior to the Merger. In January 2014, the lenders under our Prior Senior Credit Facility approved a $50 million increase in our borrowing base under our Prior Senior Credit Facility, increasing our borrowing base to $475 million See Liquidity and Capital Resources Prior Senior Credit Facility for more information regarding our Prior Senior Credit Facility.

On March 21, 2014, we were the high bidder on 21 leases at the Central Gulf of Mexico Lease Sale 231. The 21 high bid lease blocks cover a total of 92,030 acres on a gross and net basis and are all located in the shallow Gulf of Mexico within our core area of operations. Our share of the high bids totaled approximately $8.2 million.

2013 Acquisitions and Dispositions

On April 2, 2013, we sold certain shallow water GoM shelf oil and natural gas interests located within the non-operated Bay Marchand field (the BM Interests) to the property operator for $51.5 million in cash and the buyer s assumption of liabilities recorded on our balance sheet of $11.3 million resulting in total consideration of $62.8 million, subject to customary adjustments to reflect the January 1, 2013 economic effective date. Our results for the year ended December 31, 2013 reflect a pre-tax gain of $28.1 million from this sale. See Liquidity and Capital Resources Acquisitions and Dispositions in this Item 2 for more information regarding the use of proceeds from this sale.

In September and October 2013, we negotiated agreements totaling approximately $45 million with seismic companies to acquire 3D seismic licenses over our core areas. These agreements include a commitment to acquire area-wide data licenses for seismic acquisitions that will be performed by the seismic company during 2014, 2015 and 2016 covering a minimum of 200 blocks, or approximately one million acres, within the shallow water Gulf of Mexico covering our core asset base.

On September 26, 2013, we acquired from W&T Offshore, Inc. (W&T) an asset package consisting of certain GoM shelf oil and natural gas interests in the West Delta 29 field (the WD29 Interests) for $21.8 million in cash, subject to customary adjustments to reflect an economic effective date of January 1, 2013 (the WD29 Acquisition). We estimate that the proved reserves as of the January 1, 2013 economic effective date totaled approximately 0.7 Mmboe, of which 95% were oil and 58% were proved developed reserves. The WD29 Acquisition was funded with a portion of the proceeds from the sale of certain shallow water GoM shelf oil and natural gas interests located within the BM Interests described above.

On March 20, 2013, we were the high bidder on five leases at the Central Gulf of Mexico Lease Sale 227. The five high bid lease blocks cover a total of 13,892 acres on a gross and net basis and are all located in the shallow Gulf of Mexico within our core area of operations. Our share of the high bids totaled approximately $2.1 million. We have been awarded all five of the leases.

2012 Acquisitions

On October 31, 2012, we acquired from Hilcorp Energy GOM Holdings, LLC (Hilcorp) 100% of the membership interests of Hilcorp Energy GOM, LLC (the Hilcorp Acquisition), which owned certain shallow water GoM shelf oil and natural gas interest (the Hilcorp Properties) for $550.0 million in cash, subject to customary adjustments to reflect an economic effective date of July 1, 2012. As of December 31, 2012, the Hilcorp Properties had estimated proved reserves of approximately 37.2 Mmboe, of which 49% were oil and 58% were proved developed reserves. The Hilcorp Properties included the three core producing complexes of the Ship Shoal 208, South Pass 78 and South Marsh Island 239 areas and related gathering lines which are described in Part I, Item 1, Business Properties.

TABLE OF CONTENTS

The Hilcorp Acquisition was financed with cash on hand, the net proceeds from the sale of $300.0 million in aggregate principal amount of our 8.25% senior notes due 2018 (the 2012 Senior Notes) and borrowings under our Prior Senior Credit Facility. See Note 8, Indebtedness, for more information regarding our 2012 Senior Notes.

In the June 20, 2012 Central Gulf of Mexico Lease Sale 216/222, we were the high bidder on six leases covering a total of 27,148 acres on a gross and net basis located in the shallow GoM shelf within our core area of operations. Our share of the high bids totaled approximately $7.0 million.

On May 15, 2012, we acquired from W&T an asset package consisting of certain shallow-water GoM shelf oil and natural gas interests in our South Timbalier 41 field (the ST41 Interests) for $32.4 million in cash, subject to customary adjustments to reflect an economic effective date of April 1, 2012. We estimate that the proved reserves as of the April 1, 2012 economic effective date totaled approximately 1.0 Mmboe, of which 51% were oil and 84% were proved developed reserves. Prior to the ST41 Acquisition, we owned a 60% working interest in these properties, and W&T owned a 40% working interest. As a result of the ST41 Acquisition, we have become the sole working interest owner of the South Timbalier 41 field. We funded the ST41 Acquisition with cash on hand.

Overview and Outlook

As a result of pushdown accounting in connection with the Merger, the Predecessor Company s operations are deemed to have ceased on June 3, 2014 and the Successor Company began operations as of that date. In the following discussion, references to the combined operations for the six months ended June 30, 2014 combine the periods from January 1, 2014 through June 3, 2014 (reflecting the operations of the Predecessor Company) with the period from June 4, 2014 through June 30, 2014 (reflecting the operations of the Successor Company). The combined results of operations for the six months ended June 30, 2014 represent a non-GAAP financial measure due to the application of pushdown accounting and conversion to the full cost method of accounting for exploration and development activities. In addition, the consolidated financial statements of the Successor Company are not comparable to those of the Predecessor Company. However, the comparability of certain components of our operating results and key operating performance measures was not significantly impacted by the Merger, specifically those related to production, average oil and natural gas selling prices, revenues and lease operating expenses. Therefore, we believe that presenting the Successor Company s results of operations and cash flows with those of the Predecessor Company on a combined basis for the six months ended June 30, 2014 is useful when analyzing certain measures of our performance. For those items that are not comparable, we have included additional analysis to supplement the discussion.

During the six months ended June 30, 2014, we incurred capital costs of approximately $622 million. We spent approximately $314 million, including assumed asset retirement obligations, on the acquisition of the EI Interests and the SP49 Interests. We spent approximately $308 million on our front-loaded development and exploration program, which had nine different rigs running during the six month period. Additionally, we spent approximately $36.4 million in the six months ended June 30, 2014 on plugging, abandonment and other decommissioning activities.

As a result of the Merger, the future strategy of the Company is determined by Energy XXI s Board of Directors. Our fiscal year 2015 capital budget is approximately $240 million, excluding potential capitalized general and administrative expenses. The budgeted capital is allocated to development activities, which are geared toward the improvement of existing production, the continued development of core fields, and the performance of necessary plugging, abandonment and other decommissioning activities.

We continue to generate prospects, strive to maintain an extensive inventory of drillable prospects in-house and maintain exposure to new opportunities through relationships with industry partners. Our longer term operating strategy is to increase our oil and natural gas reserves and production while focusing on exploration and development costs and operating costs to remain competitive with our offshore Gulf of Mexico industry peers.

TABLE OF CONTENTS

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as oil and natural gas prices, tropical weather, economic, political and regulatory developments and availability of other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil and natural gas could have a material adverse effect on our financial position, our results of operations, our cash flows, the quantities of oil and natural gas reserves that we can economically produce and our access to capital. See Risk Factors in Part I, Item 1A of this Transition Report for a more detailed discussion of these risks.

Results of Operations Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

The following table represents information about our oil and natural gas operations.

	Period from June 4, 2014 through June 30, 2014	Period from January 1, 2014 through June 3, 2014	Non-GAAP Combined Results for the Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Net production (per day):				
Oil (Bbls)	19,113	16,922	17,285	17,591
Natural gas (Mcf)	26,410	26,502	26,487	34,352
Total (Boe)	23,515	21,339	21,700	23,316
Average sales prices[(1)]:				
Oil (per Bbl)	$ 97.93	$ 99.73	$ 99.40	$ 106.79
Natural gas (per Mcf)	4.62	4.98	4.92	3.86
Total (per Boe)	84.79	85.28	85.19	86.25
Oil and natural gas revenues (in thousands):				
Oil	$ 56,153	$ 254,827	$ 310,980	$ 340,003
Natural gas	3,658	19,945	23,603	23,982
Total	59,811	274,772	334,583	363,985
Impact of derivatives instruments settled during the period[(1)]:				
Oil (per Bbl)		$ (10.10)		$ (1.21)
Natural gas (per Mcf)		(0.15)		(0.08)
Average costs (per Boe):				
LOE	$ 25.16	$ 22.44	$ 22.93	$ 19.99
Taxes, other than on earnings	1.21	1.36	1.33	1.33
General and administrative (G&A) expenses	3.71	15.96	13.76	3.44
Increase (decrease) in oil and natural gas revenues due to:				
Changes in prices of oil			$ (23,520)	
Changes in production volumes of oil			(5,503)	
Total decrease in oil sales			(29,023)	

Changes in prices of natural gas	$6,046
Changes in production volumes of natural gas	(6,425)
Total decrease in natural gas sales	(379)

43

TABLE OF CONTENTS

(1) Subsequent to June 3, 2014, our oil and natural gas revenues and resulting average sales prices include the impact of accounting for our derivative instruments as cash flow hedges.

Overview

During the six months ended June 30, 2014, we completed 10 (9.5 net) development drilling operations and 5 (4.5 net) recompletion operations, all of which were successful. In addition, we drilled one (0.5 net) successful exploratory oil well in our Ship Shoal 208 field. One additional exploratory well that we drilled in our Main Pass 151 field during the six months ended June 30, 2014 was not successful. We are currently in the process of drilling one exploratory well in our South Timbalier 125 field.

Our operating results for the six months ended June 30, 2014, compared to the six months ended June 30, 2013, reflect a 2% decrease in oil production and a 23% decrease in natural gas production, resulting in a 7% decrease in our overall production volumes. Our product mix for the six months June 30, 2014 was 80% oil (including natural gas liquids) compared to 75% for the six months ended June 30, 2013.

Revenue

	Period from June 4, 2014 through June 30, 2014	Period from January 1, 2014 through June 3, 2014	Non-GAAP Combined Results for the Six Months Ended June 30, 2014	Six Months Ended June 30, 2013		
	(in thousands)		(in thousands)		$ Change	% Change
Oil and natural gas revenues	$ 60,143	$ 276,400	$ 336,543	$ 366,436	$ (29,893)	-8 %

For the six months ended June 30, 2014, our oil and natural gas revenues decreased 8% as compared to the six months ended June 30, 2013, due primarily to a decrease of 7% in average selling prices for our oil. The decrease in our oil and natural gas revenues also reflects the 2% decrease in oil production and 23% decrease in natural gas production, partially offset by a 27% increase in average selling prices for natural gas in the six months ended June 30, 2014, as compared to the six months ended June 30, 2013. In addition, revenues for the period from June 4, 2014 through June 30, 2014 and the non-GAAP combined revenues for the six months ended June 30, 2014 include a reduction of $1.6 million for the impact of hedge accounting

Our overall production volumes decreased by 7% for the six months ended June 30, 2014 when compared to the six months ended June 30, 2013. During the first two months of 2014, we experienced significant weather-related downtime, which negatively impacted the average oil production for the period. Our GoM shelf production decreased 6% in the six months ended June 30, 2014, as compared to the six months ended June 30, 2013, due primarily to a decrease in production in our West Delta field, which was partially offset by an increase in production in our Ship Shoal 208 area and production from the recently acquired EI Interests and SP49 Interests. Production from the EI Interests increased our production rate by approximately 1,259 Boe per day for the six months ended June 30, 2014, producing approximately 1,372 Boe per day since the acquisition date of January 15, 2014. Production from the SP 49

Interests increased our production rate by approximately 411 Boe per day for the six months ended June 30, 2014, producing approximately 2,753 Boe per day since the acquisition date of June 3, 2014.

TABLE OF CONTENTS

Operating Expenses

Our operating expenses primarily consist of the following:

	Period from June 4, 2014 through June 30, 2014	Period from January 1, 2014 through June 3, 2014	Non-GAAP Combined Results for the Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	$ Change	% Change
	(in thousands)		(in thousands)			
LOE	$ 17,746	$ 72,302	$ 90,048	$ 84,372	$5,676	7 %
Exploration expenditures and dry hole costs(1)		26,239	NM	8,463		
Impairments(1)		61	NM	2,171		
DD&A, including accretion expense(1)	24,797	96,898	NM	112,056		
G&A expenses	2,617	51,434	54,051	14,501	39,550	273 %
Taxes, other than on earnings	850	4,384	5,234	5,599	(365)	-7 %
Other		44	44	6,543	(6,499)	-99 %

NM Not meaningful.

(1) Exploration expenditures and dry hole costs, impairments, and DD&A, including accretion expense, are not comparable for the periods presented due to the conversion from successful efforts accounting to full cost accounting effective June 4, 2014. See *Discussion of Critical Accounting Policies*.

LOE increased for the six months ended June 30, 2014, compared to the six months ended June 30, 2013, primarily due to employee severance costs of $3.4 million related to the Merger. LOE for the six months ended June 30, 2014 also included approximately $3.2 million of non-routine workover expenses as compared to $6.0 million for the six months ended June 30, 2013.

Exploration expenditures and dry hole costs for the period from January 1, 2014 through June 3, 2014 include dry hole costs totaling approximately $14.8 million, primarily associated with an exploratory drilling operation which reached its target depth in June 2014 and was determined to be unsuccessful. In addition, exploration expenditures and dry hole costs for the period from January 1, 2014 through June 3, 2014 include seismic expense of $2.4 million and other exploratory costs totaling approximately $9.0 million, primarily associated with our geological and geophysical staff, including non-cash share-based compensation due to accelerated vesting of outstanding stock options and restricted shares at the time of the Merger totaling approximately $3.9 million. During the six months ended June 30, 2013, we recorded approximately $3.7 million of dry hole costs associated with an exploratory drilling operation during the quarter ended June 30, 2013. In addition, exploration expenditures and dry hole costs for six months ended June 30, 2013 include seismic expense of $1.2 million and other exploratory costs totaling approximately $3.6 million, primarily associated with our geological and geophysical staff. Prior to adopting the full cost method of accounting, our exploratory expenditures and dry hole costs could vary significantly depending on the amount of capital expenditures dedicated to exploration activities and the level of success we achieved in exploratory drilling activities.

G&A expenses increased for the six months ended June 30, 2014, as compared to the six months ended June 30, 2013, primarily due to expenses related to the Merger, including third party legal and financial advisory costs totaling approximately $11.2 million, non-cash share-based compensation due to accelerated vesting of outstanding stock options and restricted shares at the time of the Merger totaling approximately $11.8 million, employee severance costs of approximately $8.7 million and the impact of employee bonuses approved in connection with the Merger of approximately $5.1 million.

TABLE OF CONTENTS

During the six months ended June 30, 2013, we recorded loss on abandonment activities totaling $5.4 million and amortization expense related to our weather derivative of $1.3 million.

Other Income and Expense

Interest expense for the period from June 4, 2014 to June 30, 2014 includes interest on our 8.25% Senior Notes and borrowings on the revolving credit sub-facility as described in *Liquidity and Capital Resources*. For the period January 1, 2014 through June 3, 2014 and the six months ended June 30, 2013, our interest expense included interest on our 8.25% Senior Notes and interest on borrowings on the Prior Senior Credit Facility.

Other income (expense) for the period January 1, 2014 through June 3, 2014 includes a net loss on derivative instruments of $19.4 million consisting of a loss of $26.4 million on derivative instruments settled during the period primarily from the impact of higher oil prices on our oil fixed-price swaps and a gain of $7.0 million due to the change in fair value of derivative instruments to be settled in the future. Other income (expense) in the six months ended June 30, 2013 includes a net gain on derivative instruments of $23.0 million consisting of a gain of $27.3 million due to the change in fair value of derivative instruments which were to be settled in the future and a loss of $4.3 million on derivative instruments settled during the period primarily from the impact of higher oil prices on our oil fixed-price swaps.

Income Taxes

For the period from June 4, 2014 through June 30, 2014, our effective income tax rate was 35.0%, and the income tax expense we recorded was all deferred. For the period from January 1, 2014 through June 3, 2014, our effective income tax rate was negative 24%, and the income tax expense we recorded was all deferred. For the six months ended June 30, 2013, our effective income tax rate was 36.4%, and substantially all of the income tax expense we recorded was deferred. The significant change in the rate for the period from January 1, 2014 through June 3, 2014 is primarily due to significant general and administrative expenses incurred in connection with the Merger that are non-deductible for tax purposes, primarily related to stock-based compensation and transaction costs incurred.

Results of Operations   Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

The following table represents information about our oil and natural gas operations.

	Year Ended December 31,	
	2013	2012
Net production (per day):		
Oil (Bbls)	16,938	10,398
Natural gas (Mcf)	32,863	17,852
Total (Boe)	22,415	13,373
Average sales prices[1]:		
Oil (per Bbl)	$ 104.01	$ 106.08
Natural gas (per Mcf)	3.81	2.89
Total (per Boe)	84.18	86.33
Oil and natural gas revenues (in thousands):		

Oil	$ 643,033	$ 403,663
Natural gas	45,710	18,866
Total	688,743	422,529
Impact of derivatives instruments settled during the period[1]:		
Oil (per Bbl)	$ (1.78)	$ (0.88)
Natural gas (per Mcf)	(0.04)	(0.07)

46

TABLE OF CONTENTS

	Year Ended December 31,	
	2013	2012
Average costs (per Boe):		
LOE	$ 20.27	$ 19.38
Depreciation, depletion and amortization (DD&A)	24.49	23.21
Accretion of liability for asset retirement obligations	3.46	3.18
Taxes, other than on earnings	1.40	2.66
General and administrative (G&A) expenses	3.44	4.74
Increase (decrease) in oil and natural gas revenues due to:		
Changes in prices of oil	$ (7,879)	
Changes in production volumes of oil	247,249	
Total decrease in oil sales	239,370	
Changes in prices of natural gas	$ 6,017	
Changes in production volumes of natural gas	20,827	
Total increase in natural gas sales	26,844	

Overview

During the year ended December 31, 2013, we completed 16 development drilling operations, 13 of which were successful, and 21 recompletion operations, 17 of which were successful. In addition, we were 100% successful in five well operations that re-established production at existing wells, primarily within our Main Pass area. Additionally, we drilled one successful exploratory oil well in a recently-acquired primary term lease in our Main Pass 244 field that reached its target depth in September 2013 and is waiting on production facilities to commence production. One additional exploratory well that we drilled in our East Bay area during the year ended December 31, 2013 was not successful.

Our operating results for the year ended December 31, 2013, compared to the year ended December 31, 2012, reflect a 63% increase in oil production and an 84% increase in natural gas production. Our product mix for the year ended December 31, 2013 was 76% oil (including natural gas liquids) compared to 78% for the year ended December 31, 2012, resulting in a 68% increase in our overall production volumes for the year ended December 31, 2013 when compared to the year ended December 31, 2012.

Revenue and Net Income

	Years Ended December 31,			
	2013	2012		
	(in thousands)		$ Change	% Change
Oil and natural gas revenues	$ 688,743	$ 422,529	$ 266,214	63 %
Net income	85,274	58,810	26,464	45 %

For the year ended December 31, 2013, our oil and natural gas revenues increased 63% as compared to the year ended December 31, 2012, due primarily to the 63% increase in oil production, partially offset by slightly lower average selling prices for our oil. The increase in our oil and natural gas revenues also reflects the 84% increase in natural gas production and a 32% increase in average selling prices for natural gas in the year ended December 31, 2013, as compared to the year ended December 31, 2012.

Our GoM shelf production, excluding the Hilcorp Properties, increased 29% in the year ended December 31, 2013, as compared to the year ended December 31, 2012, due primarily to production increases in our West Delta, South Pass 49 and Main Pass fields partially offset by production declines in our South Timbalier area. Production from the Hilcorp Properties increased our production rate by approximately 5,902 Boe per day in the year ended December 31, 2013, compared to results for the year ended December 31, 2012, which include production from the Hilcorp Properties only for the period from November 1 to December 31, 2012, reflecting a 1,488 Boe per day impact on the production rate in the prior period.

TABLE OF CONTENTS

In addition to the items addressed above, our net income for the year ended December 31, 2013 included a gain on sale of assets of $28.7 million, primarily from the sale of the BM Interests; a loss on abandonment activities of $27.2 million; interest expense of $52.4 million and a net loss on derivative instruments of $32.4 million. Our net income for the year ended December 31, 2012 reflected a loss on abandonment activities of $2.4 million; interest expense of $28.6 million and a net loss on derivative instruments of $13.3 million.

For the years ended December 31, 2013 and 2012, our effective income tax rate was 36.8% and 33.7%, respectively, and the income tax expense that we recorded was all deferred. For the year ended December 31, 2012 the income tax expense that we recorded was reduced due to applying the change in our estimated effective income tax rate to our net deferred tax liabilities. The change in our estimated effective income tax rate from 37.3% in 2011 to 36.4% in 2012 was primarily related to estimated state income taxes.

Operating Expenses

Our operating expenses primarily consisted of the following:

	Years Ended December 31,			
	2013	2012		
	(in thousands)		$ Change	% Change
LOE	$ 165,841	$ 94,850	$ 70,991	75 %
Exploration expenditures and dry hole costs	26,555	18,799	7,756	41 %
Impairments	2,937	8,883	(5,946)	-67 %
DD&A, including accretion expense	228,658	129,146	99,512	77 %
G&A expenses	28,137	23,208	4,929	21 %
Taxes, other than on earnings	11,490	13,007	(1,517)	-12 %
Other	34,942	4,678	30,264	647 %

LOE increased for the year ended December 31, 2013, compared to the year ended December 31, 2012, primarily due to the acquisition of the Hilcorp Properties. LOE for the year ended December 31, 2013 also included approximately $8.2 million of non-routine workover expenses.

Exploration expenditures and dry hole costs increased for the year ended December 31, 2013, as compared to the year ended December 31, 2012, primarily reflecting costs associated with the increased size of our geological and geophysical staff. We also had increases in seismic expense and dry hole costs. For the year ended December 31, 2013, seismic expense, was $12.3 million compared to $10.6 million for the year ended December 31, 2012. Our seismic expense for the year ended December 31, 2013 related primarily to the 3-D seismic agreements negotiated during the year. Our seismic expense for the year ended December 31, 2012 related to area-wide 2-D and 3-D seismic purchases. For the year ended December 31, 2013, we recorded approximately $5.5 million of dry hole costs, primarily associated with an exploratory drilling operation during the year which was unsuccessful. For the year ended December 31, 2012, we recorded approximately $4.2 million of dry hole costs, primarily associated with two exploratory wells which reached their target depths in January 2012 and were determined to be unsuccessful and an unsuccessful exploratory portion of a well that was successfully completed in a development zone.

Impairments for the year ended December 31, 2013 were primarily related to reservoir performance at a gas well in one of our smaller producing fields. This field was determined to have future net cash flows less than its carrying value resulting in the write down of this property to its estimated fair value during the year ended December 31, 2013.

Impairments for the year ended December 31, 2012 were primarily due to the decline in our estimate of future natural gas prices, which affected three of our natural gas producing fields and reservoir performance at two of those fields. These fields were determined to have future net cash flows less than their carrying values resulting in the write down of these properties to their estimated fair values. We also recorded impairments for undeveloped leases that were expiring in 2013 for which we had no development plans.

DD&A increased for the year ended December 31, 2013, as compared to the year ended December 31, 2012, primarily due to the increase in production associated with the acquisition of the Hilcorp Properties.

G&A expenses increased for the year ended December 31, 2013, as compared to the year ended December 31, 2012, primarily as a result of higher professional fees related to the expansion of our asset base following the acquisition of the Hilcorp Properties and an increase in non-cash share-based compensation. G&A per Boe for the year ended December 31, 2013, as compared to the year ended December 31, 2012, declined significantly because of the increase in production primarily from the Hilcorp Properties.

Taxes, other than on earnings, were lower in the year ended December 31, 2013, as compared to the year ended December 31, 2012. The decrease was primarily related to severance taxes and a decrease in production from state leases (which is subject to a severance tax regime).

Other operating expenses increased for the year ended December 31, 2013, as compared to the year ended December 31, 2012, primarily as a result of an increase in loss on abandonment activities and amortization of the premium paid for our weather derivative. During the year ended December 31, 2013, we recorded loss on abandonment activities totaling $27.2 million and amortization expense related to our weather derivative of $8.0 million. During the year ended December 31, 2012, we recorded loss on abandonment activities totaling $2.4 million and amortization expense related to our weather derivative of $2.4 million. For the year ended December 31, 2013, our loss on abandonment activities primarily reflected an increase of $20.8 million in our asset retirement obligation liability related to our non-operated deepwater properties.

Other Income and Expense

Interest expense increased for the year ended December 31, 2013, as compared to the year ended December 31, 2012. The increase in our interest expense was due to the full year of interest on our 2012 Senior Notes and borrowings on our Prior Senior Credit Facility for the year ended December 31, 2013. For the year ended December 31, 2012, our interest expense included interest on our 2012 Senior Notes and interest on borrowings on the Prior Senior Credit Facility beginning in late October 2012 in connection with the Hilcorp Acquisition.

Other income (expense) in the year ended December 31, 2013 included a net loss on derivative instruments of $32.4 million consisting of a loss of $20.9 million due to the change in fair value of derivative instruments to be settled in the future and a loss of $11.5 million on derivative instruments settled during the period primarily from the impact of higher oil prices on our oil fixed-price swaps. Other income (expense) in the year ended December 31, 2012 includes a net loss on derivative instruments of $13.3 million consisting of a loss of $9.5 million due to the change in fair market value of derivative instruments and a loss of $3.8 million on derivative instruments settled during the period primarily from the impact of higher oil prices during 2012 on our oil fixed-price swaps.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Overview

During the year ended December 31, 2012, we completed 12 development drilling operations, 11 of which were successful, and 18 recompletion operations, 16 of which were successful. We also completed three exploratory drilling operations, one of which was successfully completed in a development zone.

Our operating results for the year ended December 31, 2012, compared to the year ended December 31, 2011, reflect a 29% increase in oil production, partially offset by lower average selling prices for our oil and natural gas. Our product mix for the year ended December 31, 2012 was 78% oil (including natural gas liquids) compared to 73% for the year ended December 31, 2011. Production from the acquired Hilcorp Properties, ST41 Interests, ASOP Properties and

Main Pass Interests had an impact of approximately 6,648 Boe per day on the production rate for the year ended December 31, 2012, compared to results for the year ended December 31, 2011, which include production from the ASOP Properties for the period from February 14, 2011 to December 31, 2011, reflecting only a 3,283 Boe per day impact on the production rate in the 2011 period.

For the year ended December 31, 2012, our total revenue increased 22% as compared to the year ended December 31, 2011, due primarily to the 29% increase in oil production. Our overall production volumes increased 21% for the year ended December 31, 2012 when compared to the year ended December 31, 2011.

TABLE OF CONTENTS

Our GoM shelf production, excluding the recently acquired Hilcorp Properties, increased 10% in the year ended December 31, 2012, as compared to the year ended December 31, 2011, due primarily to production increases in our West Delta field and production from other ASOP Properties, the Main Pass Interests and the ST41 Interests, partially offset by production declines in our predominantly natural gas fields. The Hilcorp Properties contributed 1,488 Boe per day to our production rate for the year ended December 31, 2012, producing approximately 8,944 Boe per day from November 1, 2012 through December 31, 2012. Our deepwater production, primarily natural gas, was curtailed during the year ended December 31, 2012 due to third party downstream facility modifications.

In addition to the items addressed above, our net income for the year ended December 31, 2012 includes exploration expenditures, primarily due to area-wide 2-D and 3-D seismic purchases totaling $10.6 million, impairments of $8.9 million and a net loss on derivative instruments of $13.3 million. The net income for the year ended December 31, 2011 reflects impairments of $32.5 million, a net loss on derivative instruments of $5.9 million and a $2.4 million loss on early extinguishment of debt as a result of the termination of our prior credit facility.

Our effective income tax rate for the year ended December 31, 2012 was 33.7%. The income tax expense that we recorded (all of which was deferred) for the year ended December 31, 2012 was reduced due to applying the change in our estimated effective income tax rate to our net deferred tax liabilities. The change in our estimated effective income tax rate from 37.3% in 2011 to 36.4% in 2012 was primarily related to estimated state income taxes. The effective income tax rate for the year ended December 31, 2011 was 35.8%. The income tax expense (all of which was deferred) that we recorded for the year ended December 31, 2011 was reduced due to applying the change in our estimated effective income tax rate to our net deferred tax liabilities. The change in our estimated effective income tax rate from 37.6% in 2010 to 37.3% in 2011 was primarily related to estimated state income taxes.

Revenue and Net Income

	Year Ended December 31,			
	2012	2011		
	(in thousands)		$ Change	% Change
Oil and natural gas revenues	$ 422,529	$ 348,207	$ 74,322	21 %
Net income	58,810	26,611	32,199	121 %

Our oil and natural gas revenues increased primarily as a result of the 29% increase in oil production in the year ended December 31, 2012, as compared to the year ended December 31, 2011, offset in part by a 3% decline in average selling prices for our oil and a 30% decline in average selling prices for our natural gas in the year ended December 31, 2012, as compared to the year ended December 31, 2011. Oil represented 78% of total production for the year ended December 31, 2012, as compared to 73% of total production for the year ended December 31, 2011.

Operating Expenses

Our operating expenses primarily consisted of the following:

	Year Ended December 31,			
	2012	2011		
	(in thousands)		$ Change	% Change

LOE	$ 94,850	$ 70,281	$ 24,569	35	%
Exploration expenditures and dry hole costs	18,799	14,268	4,531	32	%
Impairments	8,883	32,466	(23,583)	-73	%
DD&A, including accretion expense	129,146	120,566	8,580	7	%
G&A expenses	23,208	18,741	4,467	24	%
Taxes, other than on earnings	13,007	14,365	(1,358)	-9	%
Other	4,678	9,735	(5,057)	-52	%

50

LOE increased for the year ended December 31, 2012, compared to the year ended December 31, 2011, primarily due to the 2011 acquisitions of the ASOP Properties and Main Pass Interests and the 2012 acquisitions of the Hilcorp Properties and the ST41 Interests and approximately $3.0 million of expenses related to Hurricane Isaac in the 2012 period.

We recorded approximately $4.2 million of dry hole costs, primarily associated with two exploratory wells, which were being drilled at December 31, 2011, reached their target depths in January 2012 and were determined to be unsuccessful, and an unsuccessful exploratory portion of a well that was successfully completed in a development zone. In addition, exploration expenditures during the year ended December 31, 2012 include $10.6 million of seismic expense. We recorded approximately $11.2 million of dry hole costs associated with unsuccessful wells in the year ended December 31, 2011. In the year ended December 31, 2011, we completed drilling five exploratory wells, one of which was unsuccessful. In addition, exploration expenditures in the year ended December 31, 2011 includes $0.8 million of seismic expenditures and delay rentals.

Impairments for the year ended December 31, 2012 were primarily due to the decline in our estimate of future natural gas prices, which affected three of our natural gas producing fields and reservoir performance at two of those fields. These fields were determined to have future net cash flows less than their carrying values resulting in the write down of these properties to their estimated fair values. We also recorded impairments for undeveloped leases that were expiring in 2013 for which we had no development plans. Impairments for the year ended December 31, 2011 were primarily related to natural gas producing fields and our deepwater producing well (primarily natural gas). Impairments related to our deepwater producing well were primarily due to the decline in our estimate of future natural gas prices, reservoir performance and higher estimated operating costs. Additional impairments for the year ended December 31, 2011 were primarily related to reservoir performance at other natural gas producing fields.

G&A expenses increased for the year ended December 31, 2012, as compared to the year ended December 31, 2011, primarily as a result of an increase in employee-related costs, including an increase in non-cash share-based compensation, which was $4.7 million in the 2012 period as compared to $2.5 million in the year ended December 31, 2011.

Taxes, other than on earnings, were lower in the year ended December 31, 2012, as compared to the year ended December 31, 2011. The decrease is primarily related to severance taxes and a decrease in production from state leases (which is subject to a severance tax regime).

Other Income and Expense

Interest expense increased in the year ended December 31, 2012, as compared to the year ended December 31, 2011. For the year ended December 31, 2012, our interest expense included interest on our 2012 Senior Notes and our Prior Senior Credit Facility since the time of the issuance of the 2012 Senior Notes and borrowings on the Prior Senior Credit Facility during late October 2012 in connection with the Hilcorp Acquisition as well as interest on the $210.0 million in aggregate principal amount of our 8.25% senior notes due 2018 (the 2011 Senior Notes). For the year ended December 31, 2011, our interest expense consisted primarily of interest on our 2011 Senior Notes issued on February 14, 2011 in connection with the ASOP Acquisition.

Other income (expense) in the year ended December 31, 2012 included a net loss on derivative instruments of $13.3 million consisting of a loss of $9.5 million due to the change in fair market value of derivative instruments and a loss of $3.8 million on derivative instruments settled during the period primarily from the impact of higher oil prices during 2012 on our oil fixed-price swaps. Other income (expense) in the year ended December 31, 2011 included a net loss of $5.9 million consisting of a gain of $11.5 million due to the change in fair market value of derivative instruments and a loss of $17.4 million on derivative instruments settled during the period primarily from the impact of higher oil prices during 2011 on our oil fixed-price swaps.

Liquidity and Capital Resources

Sources and Uses of Capital

Prior Senior Credit Facility. On February 14, 2011, we entered into our senior secured credit facility with BMO Capital Markets, as lead arranger, and Bank of Montreal, as administrative agent and a lender, and the other lender parties thereto (as amended and restated, the Prior Senior Credit Facility). Our Prior Senior Credit Facility was a revolving credit facility that could be used for revolving credit loans and letters of credit. The aggregate commitment under this facility was a maximum of $750.0 million and the maturity date was October 31, 2016. The maximum amount of letters of credit that may be outstanding at any one time was $20.0 million. The amount available under the Prior Senior Credit Facility was limited by the borrowing base. The borrowing base under our Prior Senior Credit Facility had been determined at the discretion of the lenders, based on the collateral value of our proved reserves and was subject to potential special and regular semi-annual redeterminations. In January 2014, our lenders approved a $50.0 million increase in our borrowing base to $475.0 million. Prior to the Merger, we had increased our borrowings under our Prior Senior Credit Facility to $475.0 million in order to fund the SP49 Acquisition and certain costs associated with the Merger.

Effective June 3, 2014, EPL, EGC, the lenders thereunder and the other parties thereto, entered into the Eighth Amendment, dated May 23, 2014 (the Eighth Amendment) to the second amended and restated first lien credit agreement (First Lien Credit Agreement). The Eighth Amendment generally sets out the consent of the lenders thereunder to consummate the acquisition by EGC of EPL on such date and contained provisions facilitating such acquisition, including providing some of the financing for it. In addition, on May 27, 2014, EGC issued $650 million face value of 6.875% unsecured senior notes due March 15, 2024 at par. A portion of the proceeds from these notes was also used to finance the acquisition by EGC of EPL.

Most of the terms of the Eighth Amendment generally are in regards to incorporating the concept of EPL as a separate borrower for purposes of the First Lien Credit Agreement as described below. Pursuant to the Eighth Amendment, the borrowing base for EGC was established at $1.5 billion until the next redetermination of such borrowing base pursuant to the terms of the First Lien Credit Agreement. Of this borrowing base amount, EGC established a sub-facility pursuant to the Eighth Amendment for EPL, with a borrowing base of $475 million for such sub-facility. Upon the effectiveness of the Eighth Amendment, we immediately borrowed the entire $475 million to refinance the outstanding indebtedness we had under the terms of our Prior Senior Credit Facility in existence at the effective time of the Merger. As a result, on June 3, 2014, we repaid all amounts outstanding under the Prior Senior Credit Facility and our Prior Senior Credit Facility was terminated on June 3, 2014. For additional information regarding our Prior Senior Credit Facility, see Note 7, Indebtedness, to our consolidated financial statements contained in Part II, Item 8 of this Transition Report.

The borrowing base for this sub-facility is subject to redetermination from time to time generally on the same basis as is the overall borrowing base under the First Lien Credit Agreement. Under the Eighth Amendment, EGC and its subsidiaries, other than EPL and its subsidiaries, have guaranteed and secured the indebtedness of EPL and its subsidiaries, but EPL and its subsidiaries have not commensurately guaranteed the obligations of EGC and its other subsidiaries. However, per the terms of the First Lien Credit Agreement, immediately upon EPL s retirement of its obligations in respect of its outstanding 8.25% Senior Notes due 2018, EPL and its subsidiaries are required to guarantee and secure the obligations generally of EGC and its subsidiaries and such EPL sub-facility shall terminate and the entire borrowing base amount shall thereupon be available to EGC for credit extensions under the terms of the First Lien Credit Agreement. Interest accrues and is payable on the EPL sub-facility on the same basis as principal amounts outstanding generally under the First Lien Credit Agreement.

On September 5, 2014, we and EGC received written confirmation from the administrative agent under the First Lien Credit Agreement that they had received signature pages from all of the lenders under the First Lien Credit Agreement for the Ninth Amendment to the Second Amended and Restated First Lien Credit Agreement, dated as of September 5, 2014 (the Amendment). The Amendment also became effective as of such date based on satisfaction of the conditions to such effectiveness provided in the Amendment. The Amendment provides for, among other things, an adjustment to the total leverage ratio covenant under the First Lien Credit Agreement as requested by EGC. Under the Amendment, the total leverage of EGC and its consolidated subsidiaries may not exceed 4.25 times the amount of EBITDA (as defined in the First Lien

52

Credit Agreement) of EGC and its consolidated subsidiaries for the fiscal quarters ended June 30, 2014, September 30, 2014, December 31, 2014 and March 31, 2015 and may not exceed 4.00 times the amount of EBITDA for each fiscal quarter ending June 30, 2015 and thereafter. Prior to the Amendment, the total leverage ratio of EGC and its consolidated subsidiaries was required not to exceed 3.50 times EBITDA, although EGC and EPL had obtained a waiver to such requirement for the fiscal quarters ended June 30, 2014 and September 30, 2014 on August 22, 2014. The Amendment also provides for a further covenant of EGC and its subsidiaries to limit the amount of their secured debt to an amount not to exceed 1.75 times the EBITDA of EGC and its consolidated subsidiaries for the fiscal quarters ended September 30, 2014, December 31, 2014 and March 31, 2015 and 1.50 times EBITDA for any fiscal quarter ending June 30, 2015 and thereafter. Generally, the foregoing amendments under the First Lien Credit Agreement have arisen as EGC continues to consolidate our financial condition and results of operations within the scope of EGC and its subsidiaries.

Pursuant to the terms of the Amendment, the lenders under the First Lien Credit Agreement also maintained the borrowing base for EGC at $1.5 billion of which such amount $475 million is the borrowing base for EPL under the sub-facility established for EPL under the First Lien Credit Agreement. These respective borrowing bases were set in accordance with the regular annual process for determination of the borrowing bases and the borrowing bases are to remain effective until the next redetermination thereof under the terms of the First Lien Credit Agreement.

Our fiscal year 2015 capital budget is approximately $240 million, excluding potential capitalized general and administrative expenses. The budgeted capital is allocated to development activities, which are geared toward the improvement of existing production, the continued development of core fields, and the performance of necessary plugging, abandonment and other decommissioning activities. We intend to finance our capital budget with cash flow from operations, borrowings and equity investments from EGC.

Cash Flow and Working Capital. Net cash provided by operating activities was $127.3 million for the six months ended June 30, 2014. Based on our outlook of commodity prices and our estimated production, we expect to fund our fiscal year 2015 capital expenditures with cash flow from operations, borrowings and equity investments from EGC.

Our revenue, profitability, cash flows and future growth are substantially dependent upon prevailing and future prices for oil and natural gas, each of which depends on numerous factors beyond our control such as economic conditions, regulatory developments and competition from other energy sources. Oil and natural gas prices historically have been volatile, and may be subject to significant fluctuations in the future. Our derivative instruments serve to mitigate a portion of this price volatility on our cash flows.

We have incurred, and will continue to incur, capital expenditures to achieve production targets. While we expect to fund the majority of future capital expenditures with cash flow from operations, we depend on the availability of borrowings and equity investments from EGC as a source of liquidity, including for short-term working capital requirements. Based on anticipated oil and natural gas prices and availability of borrowings and equity investments from EGC, we expect to be able to fund our planned capital expenditures budget, debt service requirements and working capital needs for fiscal year 2015. In addition to EGC s borrowings under the terms of the First Lien Credit Agreement, in order to meet capital requirements, which could include the funding of future acquisitions, we or Energy XXI may also have the ability to issue debt and equity securities under our universal shelf registration statement that became effective under the Securities Act of 1933, as amended (the Securities Act) in July 2011. However, a substantial or extended decline in oil or natural gas prices could have a material adverse effect on our financial position, results of operations, cash flows and quantities of oil and natural gas reserves that may be economically produced.

At June 30, 2014, we had a working capital deficit of $194.7 million, compared to a deficit of $176.0 million at December 31, 2013. The increase in our working capital deficit as of June 30, 2014 is primarily due to increased accounts payable and accrued expenses related to exploration and development costs. The working capital deficit at December 31, 2013 was primarily due to the use of cash to repay borrowings under our Prior Senior Credit Facility, which was classified as long-term debt, increased accounts payable and accrued expenses related to exploration and development costs, the increase in the current portion of our asset retirement obligations and an increase in the current liability associated with our derivative instruments. We have experienced, and expect to experience in the future, significant working capital deficits. Our working capital deficits have historically resulted from increased accounts payable and accrued expenses related to ongoing exploration and development costs, which may be capitalized as noncurrent assets, or increased investment in oil and natural gas properties.

Capital Expenditures. During the six months ended June 30, 2014, we incurred capital costs of approximately $622 million. We spent approximately $314 million, including assumed asset retirement obligations, on the acquisition of the EI Interests and the SP49 Interests. We spent approximately $308 million on our front-loaded development and exploration program, which had nine different rigs running during the six month period. Additionally, we spent approximately $36.4 million in the six months ended June 30, 2014 on plugging, abandonment and other decommissioning activities.

Acquisitions and Dispositions. On January 15, 2014, we completed the Nexen Acquisition for $70.4 million, which was financed with borrowings under our Prior Senior Credit Facility. On June 3, 2014, we completed the SP49 Acquisition, which was financed with borrowings of approximately $135 million under our Prior Senior Credit Facility and a $95 million capital contribution from EGC.

Restricted Cash. We maintain restricted escrow funds in a trust for future plugging, abandonment and other decommissioning costs at our East Bay field. As of June 30, 2014, we had $6.0 million remaining in restricted escrow funds in the trust for decommissioning work in our East Bay field, which will remain restricted until substantially all required decommissioning in the East Bay field is complete. Amounts on deposit in the trust account are reflected in Restricted cash on our consolidated balance sheets.

8.25% Senior Notes. The 8.25% Senior Notes consist of $510.0 million in aggregate principal amount issued under an indenture dated February 14, 2011 (the 2011 Indenture). The 8.25% Senior Notes bear interest from the date of their issuance at an annual rate of 8.25% with interest due semi-annually, in arrears, on February 15th and August 15th of each year. The 8.25% Senior Notes are fully and unconditionally guaranteed, jointly and severally, on an unsecured senior basis initially by each of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries). The 8.25% Senior Notes will mature on February 15, 2018. For more information on our 8.25% Senior Notes, see Note 8, Indebtedness, to our consolidated financial statements contained in Part II, Item 8 of this Transition Report.

On April 7, 2014, Energy XXI solicited consents (the Consent Solicitation) from the holders of our 8.25% Senior Notes to make certain proposed amendments to certain definitions set forth in the 2011 Indenture (the COC Amendments). Under the COC Amendments, the Merger would not be treated as a change of control for purposes of the 101% change of control put contained in the 2011 Indenture. The Consent Solicitation was made by Energy XXI as permitted by the Merger Agreement. As a result of the consummation of the Merger, Energy XXI paid an aggregate cash payment equal to $2.50 per $1,000 principal amount of 8.25% Senior Notes for which consents to the COC Amendments were validly delivered and unrevoked to the paying agent for the Consent Solicitation on behalf of the holders who delivered such valid and unrevoked consents to the COC Amendments on or prior to 5:00 p.m. New York City time on April 17, 2014. We had no obligations to pay all or any portion of the consent fee. On April 18, 2014, we entered into a supplemental indenture (the Supplemental Indenture) to the 2011 Indenture, by and among us, the guarantors party thereto, and U.S. Bank National Association, as trustee. We entered into the Supplemental Indenture after the receipt of consents from the requisite holders of the 8.25% Senior Notes in accordance with the terms and conditions of the Consent Solicitation. As of June 30, 2014, we were in compliance with all of the covenants under the 2011 Indenture.

Analysis of Cash Flows for the Six months ended June 30, 2014

The following table sets forth our cash flows:

	Period from June 4, 2014 through June 30, 2014	Period from January 1, 2014 through June 3, 2014	Six Months Ended June 30, 2013
	(In thousands)	(In thousands)	
Net cash provided by operating activities	$ 22,209	$ 105,122	$ 192,476
Net cash used in investing activities	(200,929)	(258,714)	(154,969)
Net cash provided by (used in) financing activities	(15,729)	344,830	(35,143)

54

The decrease in our 2014 cash flows from operating activities primarily reflects decreases in revenues due to the decrease in the average selling prices for our oil and the decrease in our oil and natural gas production during the six months ended June 30, 2014, as compared to the six months ended June 20, 2013.

Net cash used in investing activities increased for the six months ended June 30, 2014, as compared to the six months ended June 30, 2013. The increase in net cash used during the six months ended June 30, 2014, as compared to the six months ended June 30, 2013, reflects our acquisition of the SP49 Interests and the EI Interests and increased exploration and development expenditures in 2014. In addition, net cash used in investing activities during the six months ended June 30, 2013 is net of the $51.7 million in proceeds from the sale of the BM Interests.

Net cash provided by financing activities during the six months ended June 30, 2014 primarily reflects borrowings of $345.0 million under our Prior Senior Credit Facility. Net cash used in financing activities during the six months ended June 30, 2013 reflects repayments of $30.0 million on our Prior Senior Credit Facility and $5.1 million for settlements of purchases of shares of our common stock (which were kept as treasury shares) pursuant to our repurchase program.

We have not paid any cash dividends in the past on our common stock. The covenants in certain debt instruments to which we are a party, including the 2011 Indenture governing the 8.25% Senior Notes, place certain restrictions and conditions on our ability to pay dividends. Any future cash dividends would depend on contractual limitations, future earnings, capital requirements, our financial condition and other factors determined by our board of directors.

Analysis of Cash Flows for the Year Ended December 31, 2013

The following table sets forth our cash flows:

	Years Ended December 31,	
	2013	2012
	(In thousands)	
Net cash provided by operating activities	$387,559	$213,871
Net cash used in investing activities	(306,339)	(764,965)
Net cash provided by (used in) financing activities	(73,929)	472,487

The increase in our 2013 cash flows from operating activities primarily reflected increases in revenues due to the increase in our oil and natural gas production during the year ended December 31, 2013, as compared to the year ended December 31, 2012.

Net cash used in investing activities decreased for the year ended December 31, 2013, as compared to the year ended December 31, 2012. Net cash used during the year ended December 31, 2013, related to an increase in exploration and development expenditures of $137.2 million compared to the year ended December 31, 2012, which was consistent with our increased capital expenditures budget for 2013. In addition, net cash used in investing activities during the year ended December, 2013 was net of the $51.7 million in proceeds from the sale of the BM Interests partially offset by property acquisitions, while the year ended December 31, 2012 included the Hilcorp Acquisition and the acquisition of the ST41 Interests.

Net cash used in financing activities during the year ended December 31, 2013 primarily reflected repayments of $65.0 million borrowed under our Prior Senior Credit Facility as well as $9.6 million for purchases of shares of our common stock (which were held as treasury shares) pursuant to our repurchase program. Net cash provided by financing activities during the year ended December 31, 2012 reflected $294.3 million of net cash proceeds from the issuance of the 2012 Senior Notes (including $4.8 million of accrued interest included in the purchase price of the 2012 Senior Notes) and $215.0 million in borrowings under our Prior Senior Credit Facility, partially offset by repayments of $20.0 million on our Prior Senior Credit Facility, expenditures of $8.5 million for financing costs primarily associated with our Prior Senior Credit Facility and offering expenses associated with our 2012 Senior Notes and $8.8 million for settlements of purchases of shares of our common stock (which were kept as treasury shares) pursuant to our repurchase program.

TABLE OF CONTENTS

Analysis of Cash Flows for the Year Ended December 31, 2012

The following table sets forth our cash flows:

	Years Ended December 31,	
	2012	2011
	(In thousands)	
Net cash provided by operating activities	$213,871	$171,252
Net cash used in investing activities	(764,965)	(310,591)
Net cash provided by (used in) financing activities	472,487	185,914

The increase in our 2012 cash flows from operating activities primarily reflected increases in revenues due to the increase in our oil production, partially offset by decreases in natural gas revenues during the year ended December 31, 2012, as compared to the year ended December 31, 2011.

Net cash used in investing activities increased in the year ended December 31, 2012, as compared to the year ended December 31, 2011, primarily due to our acquisitions of the Hilcorp Properties and the ST41 Interests during the year ended December 31, 2012. In addition, our exploration and development expenditures were higher in the year ended December 31, 2012, due to our higher 2012 capital expenditures budget. These increases were partially offset by our acquisitions of the ASOP Properties and Main Pass Interests during the year ended December 31, 2011.

Net cash provided by financing activities during the year ended December 31, 2012 reflected $294.3 million of net cash proceeds from the issuance of the 2012 Senior Notes (including $4.8 million of accrued interest included in the purchase price of the 2012 Senior Notes) and $215.0 million in borrowings under our Prior Senior Credit Facility, partially offset by repayments of $20.0 million on our Prior Senior Credit Facility, expenditures of $8.5 million for financing costs primarily associated with our Prior Senior Credit Facility and offering expenses associated with our 2012 Senior Notes and $8.8 million for settlements of purchases of shares of our common stock (which were kept as treasury shares) pursuant to our repurchase program. Net cash provided by financing activities during the year ended December 31, 2011 reflected $203.8 million of net cash proceeds (before offering expenses of $1.8 million) from the issuance of $210 million in aggregate principal amount of our 8.25% senior notes due 2018, partially offset by expenditures of $6.6 million for financing costs primarily associated with our Prior Senior Credit Facility and offering expenses associated with the 8.25% senior notes. During the year ended December 31, 2011, we also spent $11.4 million for settlements of purchases of shares of our common stock (which were kept as treasury shares) pursuant to our repurchase program.

Disclosures about Contractual Obligations and Commercial Commitments

The following table aggregates the contractual commitments and commercial obligations which affect our financial condition and liquidity position as of June 30, 2014.

	Payments Due by Period				
	Total	Less than 1 Year	1 3 Years	3 5 Years	More than 5 years
	(in thousands)				
Long-term debt	$985,000	$	$	$985,000	$

Interest on indebtedness	195,767	53,356	106,713	35,698	
Operating leases	4,659	1,199	2,241	1,084	135
Asset retirement obligations (discounted)	272,695	39,831	16,072	19,324	197,468
Drilling rig commitments	25,466	25,466			
Seismic data commitments(1)	38,000	13,000	25,000		
Total contractual obligations	$ 1,521,587	$ 132,852	$ 150,026	$ 1,041,106	$ 197,603

(1) Represents pre-commitments for seismic data purchases.

56

TABLE OF CONTENTS

Off-Balance Sheet Arrangements

We may enter into off-balance sheet transactions which may give rise to material off-balance sheet liabilities. As of June 30, 2014, the material off-balance sheet transactions entered into by us include drilling rig contracts and operating lease agreements. See contractual obligations table above. Other than the off-balance sheet transactions listed above, we have no other transactions, arrangements or relationships with other persons that are reasonably likely to materially affect our liquidity or availability of our requirements for capital resources.

Derivative Instruments

Note 1 Organization and Summary of Significant Accounting Policies and Note 10 Derivative Instruments and Hedging Activities, respectively, of our consolidated financial statements contained in Part II, Item 8 of this Transition Report describe our commodity price risks and the instruments we use to manage them.

We enter into derivative instruments to reduce our exposure to fluctuations in the market prices of oil and natural gas. Hedging transactions can expose us to risk of financial loss if, among other things, production is less than expected, the counterparty to the contract defaults on its obligations, or there is a change in the expected differential between the underlying price in the derivative instrument and actual price received. Derivative instruments may limit the benefit we would have otherwise received from increases in the sales prices of our oil and natural gas. Conversely, if we were not to engage in hedging transactions, we may be more adversely affected by declines in oil and natural gas prices than our competitors who do engage in hedging transactions.

Our revenues, profitability, cash flows and future growth are highly dependent on prices for oil and natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under the First Lien Credit Agreement is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. We currently sell all of our oil and natural gas production under price sensitive or market price contracts.

Discussion of Critical Accounting Policies

We have identified the following policies as critical to the understanding of our financial condition and results of operations. This is not a comprehensive list of all of our accounting policies. In many cases, the accounting treatment of a particular transaction is specifically dictated by GAAP, with no need for management s judgment in selecting their application. There are also areas in which management s judgment in selecting any available alternative would not produce a materially different result. However, certain accounting policies are important to the portrayal of our financial condition and results of operations and require management s most subjective or complex judgments. In applying those policies, management uses its judgment to determine the appropriate assumptions to be used in the determination of certain estimates. Those estimates are based on historical experience, observation of trends in the industry, and information available from other outside sources, as appropriate. Our critical accounting policies and estimates are set forth below. Certain of these accounting policies and estimates are particularly sensitive because of their complexity and the possibility that future events affecting them may differ materially from our management s current judgment. Our most sensitive estimate affecting our financial statements are our oil and gas reserves, which are highly sensitive to changes in oil and gas prices that have been volatile in recent years. Although decreases in oil and gas prices are partially offset by our hedging program, to the extent reserves are adversely impacted by reductions in oil and gas prices, we could experience increased depreciation, depletion and amortization expense in future periods.

Use of Estimates. The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates of proved reserves are key components of our depletion rate for our proved oil and natural gas properties and the full cost ceiling test limitation. Accordingly, our accounting estimates require exercise of judgment by management in preparing such estimates. While we believe that the estimates and assumptions used in preparation of our consolidated financial statements are appropriate, actual results could differ from those estimates, and any such difference may be material.

Proved Oil and Gas Reserves. Proved oil and gas reserves are currently defined by the SEC as those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered from existing wells with existing equipment and operating methods. Although our internal and external engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, the estimation of reserves requires the engineers to make a number of assumptions based on professional judgment. Estimated reserves are often subject to future revisions, certain of which could be substantial, based on the availability of additional information, including reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions in reserve quantities. Reserve revisions will inherently lead to adjustments of DD&A rates. We cannot predict the types of reserve revisions that will be required in future periods.

Oil and Gas Properties. Oil and natural gas exploration and production companies choose from two acceptable methods of accounting for oil and gas properties, the successful efforts method, which is the method we used prior to the Merger, and the full cost method, which we adopted subsequent to the Merger to be consistent with Energy XXI s method of accounting. The most significant difference between the two methods relates to the accounting treatment of drilling costs incurred on unsuccessful exploratory wells (dry holes) and exploration costs.

Full Cost Method. Under the full cost method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to property acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves. Oil and natural gas properties include costs that are excluded from costs being depleted or amortized. Costs excluded from depletion or amortization represent investments in unevaluated properties and include non-producing leasehold, geological and geophysical costs associated with leasehold or drilling interests and exploration drilling costs. We exclude these costs until the property has been evaluated. We also allocate a portion of our acquisition costs to unevaluated properties based on fair value. Costs are transferred to the full cost pool as the properties are evaluated or over the life of the reservoir. The capitalized costs in the full cost pool are allocated to earnings through DD&A based on the production of the pool.

Under the full cost method of accounting, we evaluate the impairment of our evaluated oil and natural gas properties through the use of a ceiling test as prescribed by SEC Regulation S-X Rule 4-10. Future production volumes from oil and natural gas properties are a significant factor in determining the full cost ceiling limitation of capitalized costs. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. Such cost estimates related to future development costs of proved oil and natural gas reserves could be subject to revisions due to changes in regulatory requirements, technological advances and other factors which are difficult to predict.

Successful Efforts Method. Under the successful efforts method of accounting for oil and natural gas producing activities, costs to acquire mineral interests in oil and natural gas properties, to drill and complete exploratory wells that found proved reserves, and to drill and complete development wells were capitalized. Exploratory drilling costs were initially capitalized, but charged to expense if and when the well was determined not to have found reserves in commercial quantities. Under this method, exploratory well costs were capitalized beyond one year if (a) we found a sufficient quantity of reserves to justify its

58

completion as a producing well and (b) we were making sufficient progress assessing the reserves and the economic and operating viability of the project; otherwise, these costs were expensed. Geological and geophysical costs were charged to expense as incurred. We allocated the capitalized cost of producing oil and gas properties to earnings through DD&A on a field-by-field basis as production occurred. Seismic, geological and geophysical, and delay rental expenditures were expensed as incurred.

We segregated the capitalized costs and recorded DD&A for capitalized property costs separately using the units-of-production method based on the ratio of (1) actual volumes in barrel equivalents produced to (2) total proved developed reserve volumes in barrel equivalents (those proved reserves recoverable through existing wells with existing equipment and operating methods), or total proved reserve volumes in barrel equivalents in the case of leasehold costs. Each period, this ratio, referred to as the DD&A rate, was applied to the applicable capitalized asset cost category, resulting in allocation of the cost of our oil and natural gas properties over the periods during which they produced revenues. Because we converted our natural gas reserves and production into barrel equivalents using six thousand cubic feet of natural gas equal to one barrel of oil, which was based on the relative energy content of natural gas and oil, the margin between the revenues realized per barrel equivalent unit of production sold compared to the DD&A recorded per unit of production varied significantly as the mix of production varied and the relative prices of natural gas and oil varied.

Under the successful efforts method, we measured impairments of our oil and natural gas properties based on the estimated fair value of oil and natural gas properties on a field-by-field basis based on the requirements of ASC Topic 360, Property, Plant and Equipment (ASC 360). We evaluated our capitalized oil and natural gas property costs for potential impairment when circumstances indicated that the carrying value may not be recoverable. Because we accumulated capitalized costs, and calculated DD&A, separately on a property by property (generally analogous to a field or a lease) basis, for our proved oil and natural gas properties under the successful efforts method of accounting, we performed impairment assessments on a property by property basis. The need to test a property for impairment was based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserve volumes, actual operating and development costs in excess of expected amounts, changes in estimates of future operating and capital expenditure requirements, or other changes to contracts or environmental regulations. Our impairment tests made use of long-term sales price assumptions for oil and natural gas. A significant amount of judgment and uncertainty was involved in performing impairment evaluations because major inputs to the computation were based on our estimates of future events, including projections of future oil and natural gas sales prices, amounts of recoverable oil and natural gas reserves, timing of future production, future costs to develop and produce our oil and natural gas and discount factors. Our assessment of possible impairment of proved oil and natural gas properties was based on our best estimate of future prices, costs and expected net future cash flows by property. An impairment loss was indicated if undiscounted net future cash flows were less than the carrying value of a property. The impairment expense was measured as the shortfall between the net book value of the property and its estimated fair value measured based on the discounted net future cash flows from the property. Actual prices, costs, and net future cash flows may have varied from our estimates. Our discount rate may not have accurately reflected economic conditions. We recognized impairments of $0.6 million, $2.9 million, $8.9 million and $32.5 million in the period from January 1, 2014 through June 3, 2014, and years ended December 31, 2013, 2012 and 2011, respectively.

For individual unevaluated properties (those with no corresponding proved reserves) with capitalized cost below a threshold amount, we allocated capitalized costs to earnings generally over the primary lease terms. We believed this method provided a reasonable estimate of the amount of capitalized costs of unevaluated properties which would prove unproductive over the primary lease terms. Properties that were subject to amortization and those with capitalized costs greater than the threshold amount were assessed for impairment periodically. If we found oil and natural gas reserves sufficient to justify development of the property, we I the net capitalized cost of the unproved property to proved properties and DD&A was recorded on the units-of-production basis described above. If our efforts did not result in proved oil and natural gas reserves, the related net capitalized costs are charged to earnings as impairment expense.

TABLE OF CONTENTS

Business Combinations. For properties acquired in a business combination, we allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes are recorded for any differences between the assigned values and tax basis of assets and liabilities. Any excess of the purchase price over amounts assigned to assets and liabilities is recorded as goodwill. Any excess of amounts assigned to assets and liabilities over the purchase price is recorded as a gain on bargain purchase. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed.

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. To estimate the fair values of these properties, we prepare estimates of oil and natural gas reserves. We estimate future prices to apply to the estimated reserves quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors.

Estimated deferred taxes are based on available information concerning the tax bases of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Goodwill. Goodwill has an indefinite useful life and is not amortized, but rather is tested for impairment at least annually during the fiscal third quarter, unless events occur or circumstances change between annual tests that would more likely than not reduce the fair value of a related reporting unit below its carrying value. Impairment occurs when the carrying amount of goodwill exceeds its implied fair value. Goodwill arose in fiscal 2014 with pushdown accounting associated with the Merger. Events affecting oil and natural gas prices may cause a decrease in the fair value of the reporting unit, and we could have an impairment of goodwill in future periods.

Asset Retirement Obligations (AROs). Our investment in oil and gas properties includes an estimate of the future cost associated with dismantlement, abandonment and restoration of our properties. The present value of the future costs are added to the capitalized cost of our oil and gas properties and recorded as a long-term or current liability. The capitalized cost is included in oil and natural gas properties cost that are depleted over the life of the assets. The estimation of future costs associated with dismantlement, abandonment and restoration requires the use of estimated costs in future periods that, in some cases, will not be incurred until a number of years in the future. Such cost estimates could be subject to revisions in subsequent years due to changes in regulatory requirements, technological advances and other factors that are difficult to predict.

Derivative Instruments. We utilize derivative instruments in the form of natural gas and crude oil put, swap and collar arrangements and combinations of these instruments in order to manage the price risk associated with future crude oil and natural gas production. Derivative instruments, including certain derivative instruments embedded in other contracts, are recorded at fair value and included as either assets or liabilities in the balance sheet. The accounting for changes in fair value depends on the intended use of the derivative and the resulting designation, which is established at the inception of the derivative.

Prior to the Merger, we did not elect to designate derivative instruments as hedges. Gains and losses resulting from changes in the fair value of derivative instruments were recorded in other income (expense). Gains and losses related to contract settlements were also recorded in other income (expense). Subsequent to the Merger, gains or losses resulting from transactions designated as cash flow hedges, recorded at market value, are deferred and recorded, net of the related tax impact, in Accumulated Other Comprehensive Income (AOCI) as appropriate, until recognized as operating income in our consolidated statement of operations as the physical production hedged by the contracts is delivered. Instruments not qualifying for hedge accounting treatment are recorded in the balance sheet and changes in fair value are recognized directly in earnings.

60

TABLE OF CONTENTS

The net cash flows related to any recognized gains or losses associated with cash flow hedges are reported as oil and natural gas revenue and presented in cash flow from operations. If a hedge is terminated prior to expected maturity, gains or losses are deferred and included in income in the same period as the physical production hedged by the contract is delivered.

The conditions to be met for a derivative instrument to qualify as a cash flow hedge are the following: (i) the item to be hedged exposes us to price risk; (ii) the derivative reduces the risk exposure and is designated as a hedge at the time the derivative contract is entered into; and (iii) at the inception of the hedge and throughout the hedge period there is a high correlation of changes in the market value of the derivative instrument and the fair value of the underlying item being hedged.

When the designated item associated with a derivative instrument matures, is sold, extinguished or terminated, derivative gains or losses are recognized as part of the gain or loss on sale or settlement of the underlying item. When a derivative instrument is associated with an anticipated transaction that is no longer expected to occur or if the correlation no longer exists, we lose our ability to use hedge accounting and the gain or loss on the derivative is recognized in income to the extent the future results have not been offset by the effects of price changes on the hedged item since the inception of the hedge.

Price volatility within a measured month is the primary factor affecting the analysis of effectiveness of our oil and gas derivatives. Volatility can reduce the correlation between the hedge settlement price and the price received for physical deliveries. Secondary factors contributing to changes in pricing differentials include changes in the basis differential which is the difference between the locally indexed price received for daily physical deliveries of the hedged quantities and the index price used in hedge settlement, as well as changes in grade and quality factors of the hedged oil and gas production that would further impact the price received for physical deliveries.

Income Taxes. Provisions for income taxes include deferred taxes resulting primarily from temporary differences due to different reporting methods for oil and natural gas properties and derivative instruments for financial reporting purposes and income tax purposes. For financial reporting purposes, all exploratory and development expenditures are capitalized and depreciated, depleted and amortized on the unit-of-production method. For income tax purposes, only the equipment and leasehold costs relative to successful wells are capitalized and recovered through depreciation or depletion. Generally, most other exploratory and development costs are charged to expense as incurred; however, we may use certain provisions of the Internal Revenue Code which allow capitalization of intangible drilling costs where management deems appropriate.

When recording income tax expense, certain estimates are required to be made by management due to timing and to the impact of future events on when income tax expenses and benefits are recognized by us. We periodically evaluate any tax operating loss and other carryforwards to determine whether a gross tax asset, as well as a valuation allowance, should be recognized in our consolidated financial statements.

See Note 12 Income Taxes in Part II, Item 8 of this Transition Report for more information regarding our deferred taxes.

Share-Based Compensation. Compensation cost for equity awards is based on the fair value of the equity instrument on the date of grant and is recognized over the period during which an employee is required to provide service in exchange for the award. Compensation cost for liability awards is based on the fair value of the vested award at the end of each reporting period. See Note 13, Employee Benefit Plans, in Part II, Item 8 of this Transition Report for a description of methods used to determine our assumptions.

New Accounting Pronouncements

For information regarding new accounting pronouncements, see the information in Note 1 Organization and Summary of Significant Accounting Policies New Accounting Pronouncements in the consolidated financial statements in Part II, Item 8 of this Transition Report.

TABLE OF CONTENTS

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view our ongoing market-risk exposure.

Interest Rate Risk

We are exposed to changes in interest rates which affect the interest earned on our interest-bearing deposits and the interest paid on borrowings under our revolving credit facility. Currently, we do not use interest rate derivative instruments to manage exposure to interest rate changes. At June 30, 2014, we had $475 million drawn under our revolving credit facility. At December 31, 2013, we had $130 million outstanding under our Prior Senior Credit Facility. Borrowings under our revolving credit facility bear interest ranging from a base rate plus a margin of 0.75% to 1.75% on base rate borrowings and LIBOR plus a margin of 1.75% to 2.75% on LIBOR borrowings. The maturity date of the revolving credit facility is April 9, 2018, provided that the facility will mature immediately if the EGC 9.25% senior notes are not retired or refinanced by June 15, 2017 or the 8.25% Senior Notes are not retired or refinanced August 15, 2017.

At June 30, 2014, our total indebtedness outstanding also includes $550.6 million (including the unamortized premium resulting from pushdown accounting of $40.6 million) related to our fixed rate 8.25% Senior Notes. At June 30, 2014, the estimated fair value of our 8.25% Senior Notes was approximately $545.7 million.

Commodity Price Risk

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our revolving credit facility is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may reduce the amount of oil and natural gas that we can economically produce. We currently sell all of our oil and natural gas production under price sensitive or market price contracts.

We use commodity derivative instruments to reduce our exposure to commodity price risks associated with future oil and natural gas production and not for trading purposes. The tables below provide information about our derivative instruments that were outstanding as of June 30, 2014. For a description of assumptions related to our calculations of fair value, please see Note 11, Fair Value Measurements, of the consolidated financial statements in Part II, Item 8 of this Transition Report.

Oil Contracts

Remaining Contract Term	Fixed-Price Swaps Daily Average Volume (Bbls)	Volume (Bbls)	Average Swap Price ($/Bbl)	Fair Value (In thousands)

July 2014	December 2014	8,769	1,613,550	92.84	(23,168)
January 2015	December 2015	1,500	547,500	97.70	(5,230)

62

TABLE OF CONTENTS

Gas Contracts

Remaining Contract Term		Type of Contract	Volume (Mmbtu)	Average Swap Price ($/Mmbtu)	Weighted Average Contract Price Sub Floor	Floor	Ceiling	Fair Value (In thousands)
July 2014	December 2014	Three-Way Collars	1,257,000		3.25	4.00	4.76	(81)
July 2014	December 2014	Put Spreads	583,000		3.25	4.00		(38)
July 2014	December 2014	Fixed Price Swaps	920,000	4.01				(409)
January 2015	December 2015	Fixed Price Swaps	1,569,500	4.31				144

The United States Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new regulation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, required the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation. In July 2012 certain definitions were adopted by the SEC and the CFTC and based on those definitions, we believe we will qualify for the end-user exception related to the clearing requirement for swaps, but we are required to adhere to new reporting and recordkeeping requirements.

TABLE OF CONTENTS

Item 8. ***Financial Statements and Supplementary Data***

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Stockholders of EPL Oil & Gas, Inc.

We have audited the accompanying consolidated balance sheet of EPL Oil & Gas, Inc. and subsidiaries (the Company) as of June 30, 2014, and the related consolidated statements of operations, comprehensive income, stockholders equity and cash flows for the periods from June 4, 2014 to June 30, 2014 and from January 1, 2014 to June 3, 2014. The Company s management is responsible for these consolidated financial statements. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of EPL Oil & Gas, Inc. and subsidiaries as of June 30, 2014, and the consolidated results of their operations and their cash flows for the periods from June 4, 2014 to June 30, 2014 and from January 1, 2014 to June 3, 2014, in conformity with accounting principles generally accepted in the United States of America.

/s/ UHY LLP
Houston, Texas
September 23, 2014

TABLE OF CONTENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of EPL Oil & Gas, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of changes in stockholders equity and of cash flows present fairly, in all material respects, the financial position of EPL Oil & Gas, Inc. and its subsidiaries (the Company) at December 31, 2013 and December 31, 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
New Orleans, Louisiana
February 27, 2014

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	SUCCESSOR COMPANY	PREDECESSOR COMPANY	
	June 30, 2014	December 31, 2013	December 31, 2012
ASSETS			
Current assets:			
Cash and cash equivalents	$ 5,601	$ 8,812	$ 1,521
Trade accounts receivable net	72,301	70,707	67,991
Fair value of commodity derivative instruments		501	3,302
Deferred tax asset	24,587	8,949	3,322
Prepaid expenses	26,521	6,868	9,873
Total current assets	129,010	95,837	86,009
Property and equipment, under the full cost method of accounting, including $908.5 million of unevaluated properties not being amortized at June 30, 2014 and at cost under the successful efforts method of accounting at December 31, 2013 and 2012, net of accumulated depreciation, depletion and amortization	3,205,187	1,736,431	1,598,067
Deposit for Nexen Acquisition		7,040	
Goodwill	327,235		
Restricted cash	6,023	6,023	6,023
Fair value of commodity derivative instruments		238	211
Deferred financing costs net of accumulated amortization of $5,549 and $2,596 at December 31, 2013 and 2012, respectively		10,106	12,386
Other assets	317	2,156	2,931
Total assets	$ 3,667,772	$ 1,857,831	$ 1,705,627
LIABILITIES AND STOCKHOLDERS EQUITY			
Current liabilities:			
Accounts payable	$ 90,923	$ 59,431	$ 34,772
Due to EGC	4,960		
Accrued expenses	161,518	131,125	117,372
Asset retirement obligations	39,831	51,601	30,179
Fair value of commodity derivative instruments	26,440	29,636	10,026
Total current liabilities	323,672	271,793	192,349
Long-term debt	1,025,566	627,355	689,911
Asset retirement obligations	232,864	203,849	204,931
Deferred tax liabilities	483,798	122,812	67,694

Fair value of commodity derivative instruments	2,140	2,136	3,637
Other	6	673	1,132
Total liabilities	2,068,046	1,228,618	1,159,654

See accompanying notes to consolidated financial statements.

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Continued)
(In thousands, except share data)

	SUCCESSOR COMPANY	PREDECESSOR COMPANY	
	June 30, 2014	December 31, 2013	December 31, 2012
Commitments and contingencies (Note 14)			
Stockholders equity:			
Preferred stock, par value $0.001 per share. Authorized 1,000,000 shares; no shares issued and outstanding at June 30, 2014 and December 31, 2013 and 2012			
Common stock, par value $0.001 per share. Authorized 75,000,000 shares; shares issued: 1,000 at June 30, 2014 and 40,970,137 and 40,601,887 at December 31, 2013 and 2012, respectively; 1,000 shares outstanding at June 30, 2014 and 39,097,394 and 39,103,203 at December 31, 2013 and 2012, respectively		41	40
Additional paid-in capital	1,599,341	519,114	510,469
Accumulated other comprehensive loss	(6,252)		
Treasury stock, at cost, no shares at June 30, 2014 and 1,872,743 and 1,498,684 shares at December 31, 2013 and 2012, respectively		(31,157)	(20,477)
Retained earnings	6,637	141,215	55,941
Total stockholders equity	1,599,726	629,213	545,973
Total liabilities and stockholders equity	$3,667,772	$1,857,831	$1,705,627

See accompanying notes to consolidated financial statements.

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS (In thousands, except per share data)

	SUCCESSOR COMPANY	PREDECESSOR COMPANY			
	Period from June 4, 2014 through June 30, 2014	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	2012	2011
Revenue:					
Oil and natural gas	$59,811	$274,772	$688,743	$422,529	$348,207
Other	332	1,628	4,295	1,104	120
Total revenue	60,143	276,400	693,038	423,633	348,327
Costs and expenses:					
Lease operating	17,746	72,302	165,841	94,850	70,281
Transportation	299	1,475	3,568	615	779
Exploration expenditures and dry hole costs		26,239	26,555	18,799	14,268
Impairments		61	2,937	8,883	32,466
Depreciation, depletion and amortization	22,775	85,127	200,359	113,581	104,624
Accretion of liability for asset retirement obligations	2,022	11,771	28,299	15,565	15,942
General and administrative	2,617	51,434	28,137	23,208	18,741
Taxes, other than on earnings	850	4,384	11,490	13,007	14,365
Gain on sales of assets			(28,681)		
Other		44	34,942	4,678	9,735
Total costs and expenses	46,309	252,837	473,447	293,186	281,201
Income from operations	13,834	23,563	219,591	130,447	67,126
Other income (expense):					
Interest income	4	17	99	136	102
Interest expense	(3,627)	(22,621)	(52,368)	(28,568)	(17,548)
Loss on derivative instruments		(19,420)	(32,361)	(13,305)	(5,870)
Loss on early extinguishment of debt					(2,377)
Total other expense	(3,623)	(42,024)	(84,630)	(41,737)	(25,693)
Income (loss) before income taxes	10,211	(18,461)	134,961	88,710	41,433
Deferred income tax expense	(3,574)	(4,495)	(49,687)	(29,900)	(14,822)
Net income (loss)	6,637	(22,956)	85,274	58,810	26,611
Basic earnings (loss) per share		(0.59)	2.18	1.50	0.66

Diluted earnings (loss) per share	(0.59)	2.15	1.50	0.66
Weighted average common shares used in computing earnings (loss) per share:				
Basic	38,730	38,730	38,885	39,946
Diluted	38,730	39,236	39,034	40,050

See accompanying notes to consolidated financial statements.

EPL OIL & GAS, INC. AND SUBSIDIARIES CONSOLIDATED STATEMENTS OF OPERATIONS (In thousands, e

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (In thousands)

	Period from June 4, 2014 through June 30, 2014
Net Income	$ 6,637
Other Comprehensive Income (Loss)	
Crude Oil and Natural Gas Cash Flow Hedges	
Unrealized change in fair value net of ineffective portion	(11,170)
Effective portion reclassified to earnings during the period	1,551
Total Other Comprehensive Loss	(9,619)
Income Tax Benefit	3,367
Net Other Comprehensive Loss	(6,252)
Comprehensive Income	$ 385

See accompanying notes to consolidated financial statements.

69

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY
(In thousands)

	Treasury Stock Shares	Treasury Stock	Common Stock Shares	Common Stock	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total
ance, December 31, 2010 Predecessor npany		$	40,092	$40	$502,556	$(29,480)	$	$473,116
income						26,611		26,611
k options and restricted share awards			217		2,509			2,509
rcise of stock options			13		119			119
chase of shares into treasury	916	(11,353)						(11,353
tricted stock used for tax withholdings	6	(8)						(8
er			4		51			51
ance, December 31, 2011 Predecessor npany	922	$(11,361)	40,326	$40	$505,235	$(2,869)	$	$491,045
income						58,810		58,810
k options and restricted share awards			226		4,717			4,717
rcise of stock options			48		441			441
chase of shares into treasury	549	(8,798)						(8,798
tricted stock used for tax withholdings	28	(318)						(318
er			2		76			76
ance, December 31, 2012 Predecessor npany	1,499	$(20,477)	40,602	$40	$510,469	$55,941	$	$545,973
income						85,274		85,274
k options and restricted share awards	2		258		7,344			7,344
rcise of stock options			108	1	1,384			1,385
chase of shares into treasury	334	(9,640)						(9,640
tricted stock used for tax withholdings	38	(1,040)						(1,040
er			2		(83)			(83
ance, December 31, 2013 Predecessor npany	1,873	$(31,157)	40,970	$41	$519,114	$141,215	$	$629,213
loss						(22,956)		(22,956
k options and restricted share awards			162		11,456			11,456
rcise of stock options					8,248			8,248
tricted stock used for tax withholdings	208	(7,637)						(7,637
er			1		26			26
ance, June 3, 2014 Predecessor Company	2,081	$(38,794)	41,133	$41	$538,844	$118,259	$	$618,350

ndown adjustments		(2,081)	38,794	(41,132)	(41)	965,497	(118,259)		885,991
income							6,637		6,637
nprehensive loss								(6,252)	(6,252
ital contribution from EGC						95,000			95,000
ance, June 30, 2014	Successor Company		$	1	$	$1,599,341	$6,637	$(6,252)	$1,599,72

See accompanying notes to consolidated financial statements.

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (In thousands)

	SUCCESSOR COMPANY	PREDECESSOR COMPANY			
	Period from June 4, 2014 through June 30, 2014	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	2012	2011
Cash flows from operating activities:					
Net income (loss)	$6,637	$(22,956)	$85,274	$58,810	$26,611
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation, depletion and amortization	22,775	85,127	200,359	113,581	104,624
Accretion of liability for asset retirement obligations	2,022	11,771	28,299	15,565	15,942
Change in fair value of derivative instruments		(6,996)	20,884	9,491	(11,475)
Non-cash compensation		19,704	7,344	4,717	2,509
Deferred income taxes	3,574	4,495	49,687	29,900	14,822
Exploration expenditures		14,825	5,520	4,227	11,239
Impairments		61	2,937	8,883	32,466
Amortization of premium, discount and deferred financing costs on debt	(841)	2,359	5,396	2,556	1,657
Gain on sales of assets			(28,681)		
Loss on early extinguishment of debt					2,377
Other		(573)	27,235	2,448	6,984
Changes in operating assets and liabilities:					
Trade accounts receivable	18,238	(21,106)	(1,916)	(33,547)	(10,037)
Other receivables					2,088
Prepaid expenses	2,415	(2,861)	2,081	1,047	(7,623)
Other assets	859	980	790	145	(1,215)
Accounts payable and accrued expenses	(29,683)	52,932	35,658	31,477	12,650
Asset retirement obligation settlements	(3,787)	(32,640)	(53,308)	(35,429)	(32,364)
Other liabilities					(3)
Net cash provided by operating activities	22,209	105,122	387,559	213,871	171,252
Cash flows provided by (used in) investing activities:					
Decrease in restricted cash					2,466
Property acquisitions	(141,886)	(60,495)	(27,560)	(578,372)	(235,486)
Deposit for Nexen Acquisition			(7,040)		

Exploration and development expenditures	(58,976)	(197,968)	(322,040)	(184,850)	(76,003)
Other property and equipment additions	(67)	(251)	(2,016)	(1,743)	(1,568)
Proceeds from sale of assets			52,317		
Net cash used in investing activities	(200,929)	(258,714)	(306,339)	(764,965)	(310,591)
Cash flows provided by (used in) financing activities:					
Proceeds from indebtedness	475,000	345,000		509,313	203,794
Repayments of indebtedness	(475,000)		(65,000)	(20,000)	
Advances to EGC	(15,729)				
Deferred financing costs		(170)	(674)	(8,469)	(6,646)
Purchase of shares into treasury			(9,640)	(8,798)	(11,353)
Exercise of stock options			1,385	441	119
Net cash provided by (used in) financing activities	(15,729)	344,830	(73,929)	472,487	185,914
Net increase (decrease) in cash and cash equivalents	(194,449)	191,238	7,291	(78,607)	46,575
Cash and cash equivalents at beginning of period	200,050	8,812	1,521	80,128	33,553
Cash and cash equivalents at end of period	$5,601	$200,050	$8,812	$1,521	$80,128
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:					
Non-cash investing information:					
Capital contribution from EGC	$95,000	$	$	$	$
Cash paid during the period for:					
Interest	1,559	23,185	47,339	21,129	9,395

See accompanying notes to consolidated financial statements.

EPL OIL & GAS, INC. AND SUBSIDIARIES CONSOLIDATED STATEMENTS OF CASH FLOWS (In thousands) 137

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies

EPL Oil & Gas, Inc. (referred to herein as we, our, us, EPL or the Company) was incorporated as a Delawa corporation on January 29, 1998 and is a wholly-owned subsidiary of Energy XXI Gulf Coast, Inc. (EGC), a Delaware corporation and indirect wholly-owned subsidiary of Energy XXI (Bermuda) Limited, an exempted company under the laws of Bermuda (Energy XXI). We operate as an independent oil and natural gas exploration and production company based in Houston, Texas and New Orleans, Louisiana. Effective September 1, 2012, we changed our legal corporate name from Energy Partners, Ltd. to EPL Oil & Gas, Inc. through a short-form merger pursuant to Section 253 of the General Corporation Law of the State of Delaware.

On June 3, 2014, Energy XXI, EGC, Clyde Merger Sub, Inc., a wholly owned subsidiary of EGC (Merger Sub), and EPL, completed the transactions contemplated by the Agreement and Plan of Merger, dated as of March 12, 2014 (as amended, the Merger Agreement), by and among Energy XXI, EGC, Merger Sub, and EPL, pursuant to which Merger Sub was merged with and into EPL with EPL continuing as the surviving corporation (the Merger). Pursuant to the Merger Agreement, at the effective time of the Merger (the Effective Time), the issued and outstanding shares of EPL common stock, par value $0.001 per share (EPL Common Stock), were converted, in the aggregate, into the right to receive merger consideration (the Merger Consideration) consisting of approximately 65% in cash and 35% in shares of common stock of Energy XXI, par value $0.005 per share (Energy XXI Common Stock). See Note 4, Common Stock for more information regarding the Merger Consideration.

Our current operations are concentrated in the U.S. Gulf of Mexico shelf (the GoM shelf) focusing on state and federal waters offshore Louisiana, which we consider our core area. We have focused on acquiring and developing assets in this region, because the region is characterized by established exploitation, development and exploration opportunities in both productive horizons and deeper geologic formations.

A summary of acquisition activity during 2014, 2013 and 2012 is as follows (purchase prices are before economic effective date adjustments):

On June 3, 2014, we acquired from Energy XXI GOM, LLC, a Delaware limited liability company and wholly-owned subsidiary of Energy XXI (Energy XXI GOM), an asset package consisting of certain shallow water GoM shelf oil and natural gas interests in our South Pass 49 field located for $230 million;
On January 15, 2014, we acquired 100% working interest of certain shallow-water central GoM shelf oil and natural gas assets comprised of five leases in the Eugene Island 258/259 field for $70.4 million;
On September 26, 2013, we acquired an asset package consisting of certain GoM shelf oil and natural gas interests in the West Delta 29 field for $21.8 million;
On October 31, 2012, we acquired from Hilcorp Energy GOM Holdings, LLC 100% of the membership interests of Hilcorp Energy GOM, LLC, which owned certain shallow water GoM shelf oil and natural gas interests for $550.0 million; and

On May 15, 2012, we acquired an asset package consisting of certain shallow-water GoM shelf oil and natural gas interests in our South Timbalier 41 field for $32.4 million.

In addition, on April 2, 2013, we sold certain shallow water GoM shelf oil and natural gas interests located within the non-operated Bay Marchand field for total consideration of $62.8 million. See Note 3, Acquisitions and Disposition for more information regarding these transactions.

A summary of significant accounting policies followed in the preparation of the accompanying consolidated financial statements is set forth below.

72

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies (continued)

(a) Basis of Presentation

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States (GAAP) and include the accounts of EPL and our wholly-owned subsidiaries. All significant intercompany accounts and transactions are eliminated in consolidation. Our interests in oil and natural gas exploration and production ventures and partnerships are proportionately consolidated.

The Merger resulted in EPL becoming an indirect, wholly owned subsidiary of Energy XXI. Therefore, in the preparation of our financial statements, we have applied pushdown accounting, based on guidance from the Securities and Exchange Commission (SEC). Pushdown accounting refers to the use of the acquiring entity s basis of accounting in the preparation of the acquired entity s financial statements. As a result, our separate financial statements reflect the new basis of accounting recorded by the Energy XXI upon acquisition. As such, in accordance with GAAP, due to our new basis of accounting, our financial statements include a black line denoting that our financial statements covering periods prior to the date of the Merger are not comparable to our financial statements as of and subsequent to the date of the Merger. References to the Predecessor Company refer to reporting dates of the Company through June 3, 2014, reflecting results of operations and cash flows of the Company prior to the Merger on our historical accounting basis; subsequent thereto, the Company is referred to as the Successor Company, reflecting the impact of pushdown accounting and the results of operations and cash flows of the Company subsequent to the Merger. See Note 2, Pushdown Accounting for more information regarding these transactions.

Energy XXI follows the full cost method of accounting for its oil and gas producing activities, while we had historically followed the successful efforts method of accounting. Subsequent to the Merger, we converted our accounting method from successful efforts to the full cost method of accounting to be consistent with Energy XXI s method of accounting pursuant to SEC guidance, which requires a reporting entity that follows the full cost method to apply that method to all of its operations and to the operations of its subsidiaries. Under GAAP, a change in accounting method is required to be applied retroactively in order to provide comparable historical period information to users of financial statements. However, due to the new basis of accounting established as a result of the Merger transaction and pushdown accounting, our financial statements are no longer comparable to those of prior periods and we have applied the full cost method of accounting on a prospective basis from the date of the Merger.

Energy XXI has a fiscal year end of June 30, while we historically had a fiscal year end of December 31. Subsequent to the Merger, we changed our year end to June 30 to be consistent with Energy XXI. Therefore, these financial statements include audited statements of operations, cash flows and stockholders equity using the successful efforts method of accounting applied to our historical basis in our assets and liabilities for the five months and three days ended June 3, 2014 and audited statements of operations, cash flows and stockholders equity using the full cost method of accounting applied to EPL s new basis in its assets and liabilities established in the Merger transaction for the twenty-seven days ended June 30, 2014, with a black line between the periods denoting that they are not comparable.

(b) Oil and Natural Gas Property and Equipment

Prior to the Merger, we used the successful efforts method of accounting for oil and natural gas producing activities. Costs to acquire mineral interests in oil and natural gas properties, to drill and complete exploratory wells that find proved reserves, and to drill and complete development wells are capitalized. Exploratory drilling costs were initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. We may have capitalized exploratory well costs beyond one year if (a) we found a sufficient quantity of reserves to justify its completion as a producing well and

73

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies (continued)

(b) we were making sufficient progress assessing the reserves and the economic and operating viability of the project; otherwise, these costs were expensed. Geological and geophysical costs were charged to expense as incurred.

Leasehold acquisition costs were capitalized as unproved properties. If proved reserves were discovered on undeveloped leases, the related leasehold costs were transferred to proved properties and amortized using the units of production method. For individual unevaluated properties with capitalized costs below a threshold amount, we allocated capitalized costs to earnings generally over the primary lease terms. Properties that were subject to amortization and those with capitalized costs greater than the threshold amount were assessed for impairment periodically. Capitalized costs of producing oil and natural gas properties were depreciated and depleted by the units-of-production method.

We evaluated our capitalized costs of proved oil and natural gas properties for potential impairment when circumstances indicated that the carrying values may not have been recoverable. The need to test a property for impairment was based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserve volumes, actual operating and development costs in excess of expected amounts, changes in estimates of future operating and capital expenditure requirements, or other changes to contracts, environmental regulations or tax laws. The calculation was performed on a field-by-field basis, utilizing our current estimates of future revenues and operating expenses. In the event net undiscounted cash flow was less than the carrying value, an impairment loss was recorded based on the present value of expected future net cash flows over the economic lives of the reserves.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depletion, depreciation and amortization were eliminated from the property accounts, along with the related asset retirement obligations, unless retained by us, and the resulting gain or loss was recognized in earnings.

As described above, subsequent to the Merger, we adopted the full cost method of accounting for exploration and development activities. Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to property acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves.

Oil and natural gas properties include costs that are excluded from costs being depleted or amortized. Costs excluded from depletion or amortization represent investments in unevaluated properties and include non-producing leasehold, geological and geophysical costs associated with leasehold or drilling interests and exploration drilling costs. We exclude these costs until the property has been evaluated. We also allocate a portion of our acquisition costs to unevaluated properties based on fair value. Costs are transferred to the full cost pool as the properties are evaluated or over the life of the reservoir.

We evaluate the impairment of our evaluated oil and natural gas properties through the use of a ceiling test as prescribed by SEC Regulation S-X Rule 4-10. Future production volumes from oil and natural gas properties are a significant factor in determining the full cost ceiling limitation of capitalized costs. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. Such cost estimates related to future development costs of proved oil and natural gas reserves could be subject to revisions due to changes in regulatory requirements, technological advances and other factors which are difficult to predict.

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies (continued)

(c) Other Property and Equipment

Other property and equipment include buildings, data processing and telecommunications equipment, office furniture and equipment, vehicle and leasehold improvements and other fixed assets. These items are recorded at cost and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets, which ranges from three to five years. Repairs and maintenance costs are expensed in the period incurred.

(d) Asset Retirement Obligations

Our investment in oil and natural gas properties includes an estimate of the future cost associated with dismantlement, abandonment and restoration of our properties. The present value of the future costs are added to the capitalized cost of our oil and natural gas properties and recorded as a long-term or current liability. The capitalized cost is included in oil and natural gas properties cost that are depleted over the life of the assets. The estimation of future costs associated with dismantlement, abandonment and restoration requires the use of estimated costs in future periods that, in some cases, will not be incurred until a substantial number of years in the future. Such cost estimates could be subject to revisions in subsequent years due to changes in regulatory requirements, technological advances and other factors which may be difficult to predict.

(e) Income Taxes

We account for income taxes under the asset and liability method, which requires that we recognize deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis amounts. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. We recognize the effect on deferred tax assets and liabilities of a change in the tax rates in income in the period that includes the enactment date.

We follow the provisions of Financial Accounting Standards Board Accounting Standards Codification (ASC) Topic 740, Income Taxes, which apply to the accounting for uncertainty in income taxes recognized in an enterprise s financial statements and prescribe a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. These provisions also contain guidance on de-recognition, classification, interest and penalties. Interest, if any, is classified as a component of interest expense, and statutory penalties, if any, are classified as a component of general and administrative expense.

(f) Deferred Financing Costs

We defer costs incurred to obtain debt financing and then amortize such costs as additional interest expense over the maturity period of the related debt using the effective interest rate method.

(g) Earnings Per Share

Basic earnings per share is computed by dividing income or loss available to common stockholders by the weighted average number of common shares outstanding during each period. According to GAAP, we have determined that our unvested restricted share awards, which contain non-forfeitable rights to dividends, are participating securities and should be included in the computation of earnings per share pursuant to the two-class method. The two-class method allocates undistributed earnings between common shares and participating securities. The diluted earnings per share calculation under the two-class method also includes the effect, if dilutive, of potential common shares associated with stock option awards outstanding during each period. The dilutive effect of stock options is determined using the treasury stock method.

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies (continued)

(h) Revenue Recognition

We record revenues from the sales of oil and natural gas when the product is delivered at a determinable price, title has transferred and collectability is reasonably assured. When we have an interest with other producers in properties from which natural gas is produced, we use the entitlement method for recording natural gas sales revenue. Under this method of accounting, revenue is recorded based on our net revenue interest in production. Deliveries of natural gas in excess of our revenue interest are recorded as liabilities and under-deliveries are recorded as receivables. We had natural gas imbalance liabilities of $2.0 million, $2.0 million and $1.7 million at June 30, 2014 and December 31, 2013 and 2012, respectively. We had natural gas imbalance receivables of $0.2 million, $1.9 million and $0.8 million at June 30, 2014 and December 31, 2013 and 2012, respectively.

(i) Cash and Cash Equivalents

We include in cash and cash equivalents our highly-liquid investments with original maturities of three months or less. At December 31, 2013 and 2012, cash and cash equivalents includes investments in overnight interest-bearing deposits of $7.3 million and $2.3 million, respectively. These amounts are reduced by overdraft balances on other operating accounts with legal right of offset in the same banking institution to arrive at the cash and cash equivalent balances reported in our consolidated balance sheets.

(j) Derivative Activities

Derivative instruments, including certain derivative instruments embedded in other contracts, are recorded at fair value and included as either assets or liabilities in the consolidated balance sheets. The accounting for changes in fair value depends on the intended use of the derivative and the resulting designation, which is established at the inception of the derivative. Prior to the Merger, we did not elect to designate derivative instruments as hedges. Gains and losses resulting from changes in the fair value of derivative instruments were recorded in other income (expense). Gains and losses related to contract settlements were also recorded in other income (expense).

Subsequent to the Merger, gains or losses resulting from transactions designated as cash flow hedges, recorded at market value, are deferred and recorded, net of the related tax impact, in Accumulated Other Comprehensive Income (AOCI) as appropriate, until recognized as operating income in our consolidated statement of operations as the physical production hedged by the contracts is delivered. Instruments not qualifying for hedge accounting treatment are recorded in the consolidated balance sheets and changes in fair value are recognized directly in earnings.

The net cash flows related to any recognized gains or losses associated with cash flow hedges are reported as oil and natural gas revenue and presented in cash flow from operations. If a hedge is terminated prior to expected maturity, gains or losses are deferred and included in income in the same period as the physical production hedged by the contract is delivered.

(k) Share-Based Compensation

We recognize share-based compensation expense based on the estimated grant-date fair value of all share-based awards, net of an estimated forfeiture rate, over the requisite service period of the awards, which is generally equivalent to the vesting term. We record share-based compensation expense only for those awards expected to vest. We periodically revise our estimated forfeiture rate if actual forfeitures differ from our estimates. Compensation expense for liability awards is based on the fair value of the vested award at the end of each reporting period.

We are required to report excess tax benefits from the exercise of stock options as financing cash flows. For the period from January 1, 2014 through June 3, 2014 and the years ended December 31, 2013 and 2012, no excess tax benefits were reported in the statement of cash flows as we were in a net operating loss carryforward position. See Note 12, Income Taxes, for additional disclosures.

76

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies (continued)

(l) Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are stated at historical carrying amount net of allowance for doubtful accounts. We establish provisions for losses on accounts receivable if it is determined that collection of all or a part of an outstanding balance is not probable. Collectability is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of June 30, 2014, no allowance for doubtful accounts was necessary. As of December 31, 2013, our allowance for doubtful accounts was $0.7 million, $0.1 million of which was recorded as a recovery in earnings in 2013. As of December 31, 2012, our allowance for doubtful accounts was $0.7 million, $0.1 million of which was recorded as a recovery in earnings in 2012.

(m) Accrued Expenses

As of June 30, 2014, our accrued expenses included accrued exploration costs, development costs and lease operating expenses totaling approximately $127.6 million, other accrued expenses of $18.1 million and interest payable of approximately $15.8 million. As of December 31, 2013, our accrued expenses included accrued exploration costs, development costs and lease operating expenses totaling approximately $107.8 million, other accrued expenses of $7.5 million and interest payable of approximately $15.8 million. As of December 31, 2012, our accrued expenses included accrued exploration costs, development costs and lease operating expenses totaling approximately $84.9 million, other accrued expenses of $16.3 million and interest payable of approximately $16.2 million.

(n) Goodwill

We recorded goodwill during 2014 as a result of pushdown accounting in conjunction with the Merger. Goodwill has an indefinite useful life and is not amortized, but rather is tested for impairment at least annually during the fiscal third quarter, unless events occur or circumstances change between annual tests that would more likely than not reduce the fair value of a related reporting unit below its carrying value. Impairment occurs when the carrying amount of goodwill exceeds its implied fair value. Events affecting crude oil and natural gas prices may cause a decrease in the fair value of the reporting unit, and we could have an impairment of goodwill in future periods.

(o) Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We use historical experience and various other assumptions that are believed to be reasonable under the circumstances to form the basis for making judgments about carrying values of assets and liabilities that are not readily apparent from other sources. Our actual results may differ from these estimates and assumptions used in preparation of our financial statements. Significant estimates with regard to these financial statements and related unaudited disclosures include the estimate of proved oil and natural gas reserve quantities and the related present value of estimated future net cash flows therefrom disclosed in Note 18, Supplementary Oil and Natural Gas Disclosures .

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies (continued)

(p) New Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers* (ASU 2014-09). ASU 2014-09 provides a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and will supersede most current revenue recognition guidance. The standard is effective for public entities for annual and interim periods beginning after December 15, 2016. Early adoption is not permitted. We are currently evaluating the provisions of ASU 2014-09 and assessing the impact, if any, it may have on our financial position, results of operations or cash flows.

In August 2014, the FASB issued Accounting Standards Update No. 2014-15, *Disclosure of Uncertainties about an Entity s Ability to Continue as a Going Concern* (ASU 2014-15). ASU 2014-15 requires management to assess an entity s ability to continue as a going concern, and to provide related footnote disclosures in certain circumstances. The standard is effective for public entities for annual and interim periods beginning after December 15, 2016, with early adoption permitted. We are currently evaluating the provisions of ASU 2014-15 and assessing the impact, if any, it may have on our financial position, results of operations or cash flows.

(2) Pushdown Accounting

As described in Note 1, the Merger resulted in EPL becoming an indirect, wholly owned subsidiary of Energy XXI. Therefore, we have applied pushdown accounting, based on guidance from the SEC. The following table reflects the impact on our condensed consolidated balance sheet of the pushdown accounting adjustments required to reflect the fair value of our assets acquired and liabilities assumed by Energy XXI in the Merger:

	PREDECESSOR COMPANY June 3, 2014	PUSHDOWN ADJUSTMENTS	SUCCESSOR COMPANY June 3, 2014
ASSETS			
Current assets:			
Cash and cash equivalents	$ 200,050	$	$ 200,050
Trade accounts receivable net	91,813	1,194	93,007
Deferred tax asset	8,405	16,182	24,587
Prepaid expenses	9,729	80	9,809
Total current assets	309,997	17,456	327,453
Property and equipment, net of accumulated depreciation,	1,969,382	972,510	2,941,892

depletion and amortization			
Goodwill		327,235	327,235
Restricted cash	6,023		6,023
Fair value of commodity derivative instruments	27		27
Deferred financing costs	9,002	(9,002)	
Other assets	1,175		1,175
Total assets	$ 2,295,606	$ 1,308,199	$ 3,603,805
LIABILITIES AND STOCKHOLDERS EQUITY			
Current liabilities:			
Accounts payable	$ 61,938	$	$ 61,938
Accrued expenses	230,086		230,086
Asset retirement obligations	39,859	3,758	43,617

78

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(2) Pushdown Accounting (continued)

	PREDECESSOR COMPANY June 3, 2014	PUSHDOWN ADJUSTMENTS	SUCCESSOR COMPANY June 3, 2014
Fair value of commodity derivative instruments	22,625		22,625
Total current liabilities	354,508	3,758	358,266
Long-term debt	973,440	52,967	1,026,407
Asset retirement obligations	220,302	9,453	229,755
Deferred tax liabilities	126,764	356,827	483,591
Fair value of commodity derivative instruments	1,439		1,439
Other	803	(797)	6
Total liabilities	1,677,256	422,208	2,099,464
Commitments and contingencies			
Stockholders equity:			
Preferred stock, par value $0.001 per share.			
Common stock, par value $0.001 per share.	41	(41)	
Additional paid-in capital	538,844	965,497	1,504,341
Treasury stock, at cost	(38,794)	38,794	
Retained earnings	118,259	(118,259)	
Total stockholders equity	618,350	885,991	1,504,341
Total liabilities and stockholders equity	$ 2,295,606	$ 1,308,199	$ 3,603,805

In accordance with the acquisition method of accounting, the purchase price established in the Merger has been allocated to the assets acquired and liabilities assumed based on their estimated fair values on the acquisition date. The fair value estimates were based on, but not limited to quoted market prices, where available; expected future cash flows based on estimated reserve quantities; estimated costs to produce and develop reserves; current replacement cost for similar capacity for certain fixed assets; market rate assumptions for contractual obligations; appropriate discount rates and growth rates; and crude oil and natural gas forward prices. Deferred income taxes have been recognized based on the estimated fair value adjustments to net assets using a 37 percent tax rate, which reflected the 35 percent federal statutory rate and a 2 percent weighted-average of the applicable statutory state tax rates (net of federal benefit). The excess of the total consideration over the estimated fair value of the amounts initially assigned to the identifiable assets acquired and liabilities assumed has been recorded as goodwill. Goodwill recorded in connection with the acquisition is not deductible for income tax purposes.

The final valuation of assets acquired and liabilities assumed is not complete and the net adjustments to those values may result in changes to goodwill and other carrying amounts initially assigned to the assets and liabilities based on the preliminary fair value analysis. The principal remaining items to be valued are tax assets and liabilities, and any related valuation allowances, which will be finalized in connection with the filing of related tax returns.

The fair value measurements of the oil and natural gas properties and the asset retirement obligations included in other long-term liabilities were based, in part, on significant inputs not observable in the market and thus represent Level 3 measurements. The fair value measurement of long-term debt was based on prices obtained from a readily available pricing source and thus represents a Level 2 measurement.

Goodwill primarily resulted from the requirement to recognize deferred taxes on the difference between the fair value and the historical tax basis of the acquired assets. At June 30, 2014, we conducted a qualitative goodwill impairment assessment by examining relevant events and circumstances that could have a negative impact on our goodwill, such as macroeconomic conditions, industry and market conditions, cost factors that have a negative effect on earnings and cash flows, overall financial performance, dispositions and acquisitions,

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(2) Pushdown Accounting (continued)

and any other relevant events or circumstances. After assessing the relevant events and circumstances for the qualitative impairment assessment, we determined that performing a quantitative goodwill impairment test was unnecessary, and no goodwill impairment was recognized.

(3) Acquisitions and Dispositions

The South Pass 49 Acquisition

On June 3, 2014 we acquired from Energy XXI GOM an asset package consisting of certain shallow-water GoM shelf oil and natural gas interests in our South Pass 49 field (the SP49 Interests) for $230.0 million, subject to customary adjustments to reflect an economic effective date of June 1, 2014 (the SP49 Acquisition). We estimate that the proved reserves as of the June 1, 2014 economic effective date totaled approximately 11.3 Mmboe, of which 74% were oil and 73% were proved developed reserves. Prior to the SP49 Acquisition, we owned a 43.5% working interest in certain of these assets, and Energy XXI owned a 56.5% working interest in certain of these assets as well as 100% interest in additional assets in the field. As a result of the SP49 Acquisition, we have become the sole working interest owner of the South Pass 49 field. We financed the SP49 Acquisition with borrowings of approximately $135 million under our credit facility and a $95 million capital contribution from EGC. See Note 8, Indebtedness for more information regarding our credit facility.

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects management s estimate of customary adjustments of $0.2 million to reflect an economic effective date of June 1, 2014.

(In thousands)	June 1, 2014
Oil and natural gas properties	$ 231,271
Asset retirement obligations	(1,086)
Net assets acquired	$ 230,185

The Nexen Acquisition

On January 15, 2014, we acquired from Nexen Petroleum Offshore U.S.A., Inc. (Nexen) 100% working interest of certain shallow-water central GoM shelf oil and natural gas assets for $70.4 million, subject to customary adjustments to reflect the September 1, 2013, economic effective date (the Nexen Acquisition). The assets we acquired comprise five leases in the Eugene Island 258/259 field (the EI Interests). Estimated proved reserves as of the September 1, 2013 effective date consist of approximately 2.6 Mmboe of proved developed producing reserves, about 91% of which is oil. The Nexen Acquisition was financed with borrowings under our senior secured credit facility with BMO Capital Markets, as lead arranger, and Bank of Montreal, as administrative agent and a lender, and the other lender parties thereto (as amended and restated, the Prior Senior Credit Facility).

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects management s estimate of customary adjustments of $5.7 million to reflect an economic effective date of September 1, 2013.

(In thousands)	September 1, 2013
Oil and natural gas properties	$ 82,897
Asset retirement obligations	(18,165)
Net assets acquired	$ 64,732

80

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(3) Acquisitions and Dispositions (continued)

The West Delta 29 Acquisition

On September 26, 2013, we acquired from W&T Offshore, Inc. (W&T) an asset package consisting of certain GoM shelf oil and natural gas interests in the West Delta 29 field (the WD29 Interests) for $21.8 million in cash, subject to customary adjustments to reflect an economic effective date of January 1, 2013 (the WD29 Acquisition). We estimate that the proved reserves as of the January 1, 2013 economic effective date totaled approximately 0.7 Mmboe, of which 95% were oil and 58% were proved developed reserves. The WD29 Acquisition was funded with a portion of the proceeds from the sale of the BM Interests held by the qualified intermediary as described below.

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects final adjustments to purchase price provided for by the purchase and sale agreement of approximately $7.1 million to reflect an economic effective date of January 1, 2013.

(In thousands)	January 1, 2013
Oil and natural gas properties	$ 16,544
Asset retirement obligations	(1,398)
Net assets acquired	$ 15,146

Sale of Non-Operated Bay Marchand Asset

On April 2, 2013, we sold certain shallow water GoM shelf oil and natural gas interests located within the non-operated Bay Marchand field (the BM Interests) to the property operator for $51.5 million in cash and the buyer s assumption of liabilities recorded on our balance sheet of $11.3 million resulting in total consideration of $62.8 million, subject to customary adjustments to reflect the January 1, 2013 economic effective date. Our results for the year ended December 31, 2013 reflect a pre-tax gain of $28.1 million from this sale.

The following table summarizes the carrying amount of the net assets sold and reflects final adjustments to the sale price provided for by the purchase and sale agreement of approximately $0.7 million to reflect the economic effective date of January 1, 2013.

(In thousands)	January 1, 2013
Oil and natural gas properties	$ 35,298
Asset retirement obligations	(3,959)
Other liabilities	(7,311)
Net assets sold	$ 24,028

The cash proceeds from this sale of assets were held on deposit with a qualified intermediary in contemplation of a potential tax-deferred exchange of properties and classified as restricted cash at June 30, 2013. On September 26, 2013, we used $16.5 million of these proceeds to fund the WD29 Acquisition (defined and described above), which was a qualifying purchase for tax-deferral purposes. On September 29, 2013, the underlying escrow agreement expired, and the remaining amount of the deposit became unrestricted.

The Hilcorp Acquisition

On October 31, 2012, we acquired from Hilcorp Energy GOM Holdings, LLC (Hilcorp) 100% of the membership interests of Hilcorp Energy GOM, LLC (the Hilcorp Acquisition), which owned certain shallow water GoM shelf oil and natural gas interest (the Hilcorp Properties) for $550.0 million in cash, subject to customary adjustments to reflect an economic effective date of July 1, 2012. As of December 31, 2012, the Hilcorp Properties had estimated proved reserves of approximately 37.2 Mmboe, of which 49% were oil and 58% were proved developed reserves.

81

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(3) Acquisitions and Dispositions (continued)

The Hilcorp Acquisition was financed with cash on hand, the net proceeds from the sale of $300 million in aggregate principal amount of 8.25% senior notes due 2018 (the 2012 Senior Notes) and borrowings under our Prior Senior Credit Facility. See Note 8, Indebtedness, for more information regarding our 2012 Senior Notes.

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects final adjustments to purchase price provided for by the purchase and sale agreement of approximately $5.7 million to reflect an economic effective date of July 1, 2012.

(In thousands)	July 1, 2012
Oil and natural gas properties	$ 698,660
Asset retirement obligations	(150,959)
Net assets acquired	$ 547,701

During the quarter ended December 31, 2013, we completed the allocation of the Hilcorp Acquisition purchase price resulting in an increase in the acquired asset retirement obligation of $22.1 million. This change was due primarily to changes in the timing of expected cash flows for the related abandonment and decommissioning activities.

The South Timbalier Acquisition

On May 15, 2012, we acquired from W&T an asset package consisting of certain shallow-water GoM shelf oil and natural gas interests in our South Timbalier 41 field (the ST41 Interests) for $32.4 million in cash, subject to customary adjustments to reflect an economic effective date of April 1, 2012. We estimate that the proved reserves as of the April 1, 2012 economic effective date totaled approximately 1.0 Mmboe, of which 51% were oil and 84% were proved developed reserves. Prior to the ST41 Acquisition, we owned a 60% working interest in these properties, and W&T owned a 40% working interest. As a result of the ST41 Acquisition, we have become the sole working interest owner of the South Timbalier 41 field. We funded the ST41 Acquisition with cash on hand.

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects final adjustments to purchase price provided for by the purchase and sale agreement of approximately $0.4 million to reflect an economic effective date of April 1, 2012.

(In thousands)	April 1, 2012
Oil and natural gas properties	$ 33,206
Asset retirement obligations	(1,878)
Net assets acquired	$ 31,328

We have accounted for our acquisitions using the acquisition method of accounting for business combinations, and therefore we have estimated the fair value of the assets acquired and the liabilities assumed as of their respective acquisition dates. In the estimation of fair value, management uses various valuation methods including (i) comparable company analysis, which estimates the value of the acquired properties based on the implied valuations of other similar operations; (ii) comparable asset transaction analysis, which estimates the value of the acquired operations based upon publicly announced transactions of assets with similar characteristics; (iii) comparable merger transaction analysis, which, much like comparable asset transaction analysis, estimates the value of operations based upon publicly announced transactions with similar characteristics, except that merger analysis analyzes public to public merger transactions rather than solely asset transactions; and (iv) discounted cash flow analysis. The fair value is based on subjective estimates and assumptions, which are inherently subject to significant uncertainties which are beyond our control. These assumptions represent Level 3 inputs, as further discussed in Note 11, Fair Value Measurements.

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(3) Acquisitions and Dispositions (continued)

Results of Operations and Pro Forma Information

Revenues and lease operating expenses attributable to acquired interests and properties were as follows:

	Period from June 4, 2014 through June 30, 2014	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	2012
	(In thousands)	(In thousands)		
SP49 Interests:				
Revenues	$ 5,126	$	$	$
Lease operating expenses	$ 600	$	$	$
EI Interests:				
Revenues	$ 4,379	$ 17,565	$	$
Lease operating expenses	$ 1,151	$ 7,264	$	$
WD29 Interests:				
Revenues	$ 1,232	$ 5,681	$ 3,011	$
Lease operating expenses	$ 12	$ 89	$ 44	$
Hilcorp Properties:				
Revenues	$ 22,455	$ 100,571	$ 208,241	$ 37,978
Lease operating expenses	$ 7,489	$ 29,189	$ 74,404	$ 10,982
ST41 Interests:				
Revenues	$ 843	$ 3,406	$ 11,189	$ 9,262
Lease operating expenses	$ 148	$ 1,217	$ 2,468	$ 1,760

We have determined that the presentation of net income attributable to the acquired interests and properties is impracticable due to the integration of the related operations upon acquisition. We incurred fees of approximately $0.3 million related to the SP49 Acquisition which were included in general and administrative expenses in the accompanying consolidated statement of operations for the period June 4, 2014 through June 30, 2014. We incurred fees of approximately $0.1 million related to the Nexen Acquisition which were included in general and administrative expenses in the accompanying consolidated statement of operations for the period January 1, 2014 through June 3, 2014. We incurred fees of approximately $0.5 million related to the Hilcorp Acquisition and approximately $0.1 million related to the ST41 Acquisition, which were included in general and administrative expenses in the accompanying consolidated statement of operations for the year ended December 31, 2012.

The following supplemental pro forma information presents consolidated results of operations as if the WD 29 Acquisition, the Nexen Acquisition and SP 49 Acquisition had occurred on January 1, 2013. The supplemental unaudited pro forma information was derived from a) our historical consolidated statements of operations, b) the audited statement of revenues and direct operating expenses of the SP49 Interests for the year ended December 31, 2013, c) the unaudited statement of revenues and direct operating expenses of the SP49 Interests for the five month and three day period ended June 3, 2014, and d) unaudited revenues and direct operating expenses of the WD 29 Interests and the EI Interests as derived from the records of the applicable seller provided to us in connection with the acquisitions. This information does not purport to be indicative of results of operations that would have occurred had the acquisitions occurred on January 1, 2013, nor is such information indicative of any expected future results of operations.

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(3) Acquisitions and Dispositions (continued)

	PRO FORMA Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013
	(in thousands, except per share data)	
Revenue	$ 303,742	$ 823,436
Net income (loss)	(15,546)	122,391
Basic earnings (loss) per share	(0.40)	3.13
Diluted earnings (loss) per share	(0.40)	3.09

(4) Common Stock

The Merger became effective on June 3, 2014. For each share of our common stock held, shareholders had the right to elect to receive $39.00 in cash or 1.669 shares of Energy XXI common stock or $25.35 in cash and 0.584 of a share of Energy XXI common stock. As a result of the Merger our securities were suspended from trading on June 4, 2014. Our common stock was then removed from listing and registration on the New York Stock Exchange (the NYSE) on July 15, 2014.

We had reserved up to 3,574,000 shares of common stock for the issuance of restricted shares and option shares under our 2009 Long-Term Incentive Plan, with 1,087,347 shares remaining for issuance. See Note 13, Employee Benefit Plans for information regarding the 2009 Long-Term Incentive Plan.

In August 2011, the former Board of Directors of EPL authorized a program for the repurchase of our outstanding common stock for up to an aggregate cash purchase price of $20.0 million and increased the program to $40.0 million in May 2012. In July 2013, the former Board of Directors increased the program to $80.0 million. Through December 31, 2013, we executed trades to repurchase 1,799,000 shares at an aggregate cash purchase price of approximately $29.7 million. Such shares were held in treasury and could be used to provide available shares for possible resale in future public or private offerings and our employee benefit plans. The repurchases were carried out in accordance with certain volume, timing and price constraints imposed by the SEC rules applicable to such transactions. In July 2013, our Prior Senior Credit Facility was amended to increase the limit applicable to certain restricted payments, which includes share repurchases, permitted by the agreement.

Covenants in certain debt instruments to which we are a party, including the indenture related to our 8.25% Senior Notes, place certain restrictions and conditions on our ability to pay dividends on our common stock.

(5) Earnings Per Share

The following table sets forth the calculation of basic and diluted weighted average shares outstanding and earnings per share for the indicated periods.

	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	2012	2011
		(in thousands, except per share data)		
Income (numerator):				
Net income (loss)	$ (22,956)	$ 85,274	$ 58,810	$ 26,611
Net income attributable to participating securities		(943)	(455)	(77)
Net income (loss) attributable to common shares	$ (22,956)	$ 84,331	$ 58,355	$ 26,534

84

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(5) Earnings Per Share (continued)

	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	2012	2011
		(in thousands, except per share data)		
Weighted average shares (denominator):				
Weighted average shares basic	38,730	38,730	38,885	39,946
Dilutive effect of stock options		506	149	104
Weighted average shares diluted	38,730	39,236	39,034	40,050
Basic earnings (loss) per share	$ (0.59)	$ 2.18	$ 1.50	$ 0.66
Diluted earnings (loss) per share	$ (0.59)	$ 2.15	$ 1.50	$ 0.66

The following table indicates the number of shares underlying outstanding stock-based awards excluded from the computation of dilutive weighted average shares because their effect was antidilutive for the periods indicated.

	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	2012	2011
	(in thousands)		(in thousands)	
Weighted average shares	941	273	687	442

(6) Property and Equipment

The following table summarizes our property and equipment.

	June 30, 2014
	(In thousands)
Proved oil and natural gas properties	$2,316,306
Unevaluated oil and natural gas properties	908,483
Other	3,173

Less: accumulated depreciation, depletion and amortization	(22,775)
Total property and equipment, net of accumulated depreciation, depletion and amortization	$3,205,187

	December 31, 2013	2012
	(In thousands)	
Proved oil and natural gas properties	$2,307,891	$1,982,657
Unproved oil and natural gas properties	39,191	36,992
Other	8,137	5,998
Less: accumulated depreciation, depletion and amortization	(618,788)	(427,580)
Total property and equipment, net of accumulated depreciation, depletion and amortization	$1,736,431	$1,598,067

85

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(6) Property and Equipment (continued)

At June 30, 2014 and December 31, 2013, we did not have any exploratory projects that were suspended for a period greater than one year.

Substantially all of our oil and natural gas properties serve as collateral under our credit facility.

We recognized impairments of $0.1 million, $2.9 million, $8.9 million and $32.5 million in the period from January 1, 2014 through June 3, 2014 and the years ended December 31, 2013, 2012 and 2011, respectively.

Impairments for the year ended December 31, 2013 were primarily related to reservoir performance at a gas well in one of our smaller producing fields. This field was determined to have future net cash flows less than its carrying value resulting in the write down of this property to its estimated fair value.

Impairments for the year ended December 31, 2012 were primarily due to the decline in our estimate of future natural gas prices affecting certain of our natural gas producing fields and to reservoir performance at two of those fields. These fields were determined to have future net cash flows less than their carrying values resulting in the write down of these properties to their estimated fair values. We also recorded impairments for undeveloped leases that are expiring in 2013 for which we had no development plans.

Impairments for the year ended December 31, 2011 were primarily related to our natural gas producing fields and our deepwater producing well (primarily natural gas). Impairments related to our deepwater producing well were primarily due to the decline in our estimate of future natural gas prices, reservoir performance and higher estimated operating costs. Additional impairments for the year ended December 31, 2011 were primarily related to reservoir performance at other natural gas producing fields.

(7) Asset Retirement Obligations

The following table reconciles the beginning and ending aggregate recorded amount of our asset retirement obligations (ARO).

	Period from June 4, 2014 through June 30, 2014	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	Year Ended December 31, 2012
	(in thousands)	(in thousands)		

Beginning of period total	$ 260,161	$ 255,450	$ 235,110	$ 99,347
Accretion expense	2,022	11,771	28,299	15,565
Liabilities assumed in acquisitions	1,086	18,165	23,541	132,109
Pushdown accounting fair value adjustment	13,213			
Liabilities incurred			1,187	1,210
Revisions		7,415	24,586	22,308
Liabilities associated with assets sold			(3,965)	
Liabilities settled	(3,787)	(32,640)	(53,308)	(35,429)
End of period total	272,695	260,161	255,450	235,110
Less: End of period, current portion	(39,831)	(39,859)	(51,601)	(30,179)
End of period, noncurrent portion	$ 232,864	$ 220,302	$ 203,849	$ 204,931

The fair value adjustment recorded in pushdown accounting resulted from conforming to Energy XXI s inflation and discount rate assumptions.

86

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(7) Asset Retirement Obligations (continued)

We revise our estimates of ARO as information about material changes to the liability becomes known. During the year ended December 31, 2013, our revisions include an increase to our estimated ARO of $20.8 million related to our only remaining four non-producing wellbores in our non-operated deepwater properties. These deepwater abandonment costs were primarily attributable to changes in regulatory interpretations and enforcement by the Bureau of Safety and Environmental Enforcement (BSEE) in the deepwater that increased the required scope of work. As a result, we recorded an associated $20.8 million loss on abandonment activities, which is included in Other costs and expenses in our consolidated statements of operations for the year ended December 31, 2013.

(8) Indebtedness

The following table sets forth our indebtedness.

	June 30, 2014	December 31, 2013	December 31, 2012
	(In thousands)	(In thousands)	
8.25% senior notes due 2018	$ 550,566	$ 497,355	$ 494,911
Revolving credit sub-facility	475,000		
Senior credit facility		130,000	195,000
Total indebtedness	1,025,566	627,355	689,911
Current portion of indebtedness			
Noncurrent portion of indebtedness	$ 1,025,566	$ 627,355	$ 689,911

8.25% Senior Notes

The 8.25% senior notes consist of $510.0 million in aggregate principal amount ($550.6 million carrying value) of our 8.25% senior notes due 2018 (the 8.25% Senior Notes) issued under an Indenture dated February 14, 2011 (the 2011 Indenture). The 8.25% Senior Notes bear interest from the date of their issuance at an annual rate of 8.25% with interest due semi-annually, in arrears, on February 15th and August 15th of each year. The 8.25% Senior Notes are fully and unconditionally guaranteed, jointly and severally, on an unsecured senior basis initially by each of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries). The 8.25% Senior Notes will mature on February 15, 2018. At June 30, 2014, the effective interest rate on the 8.25% Senior Notes was approximately 5.8%, reflecting the fair value adjustment recorded in pushdown accounting. Prior to pushdown accounting, the effective interest rate was approximately 9.1%. We issued the 8.25% Senior Notes in two different private placements, described below.

On February 14, 2011, we issued the $210.0 million in aggregate principal amount of our 8.25% senior notes due 2018 (the 2011 Senior Notes) under the 2011 Indenture. We used the net proceeds from the offering of the 2011

Senior Notes of $202.0 million, after deducting the initial purchasers discount and offering expenses payable by us, to acquire an asset package for a purchase price of $200.7 million, before adjustments to reflect an economic effective date of January 1, 2011.

On October 25, 2012, we issued the $300.0 million in aggregate principal amount of our 2012 Senior Notes under an Indenture dated as of October 25, 2012 (the 2012 Indenture). We used the net proceeds from the offering of the 2012 Senior Notes of $289.5 million, after deducting the initial purchasers discount, to fund a portion of the Hilcorp Acquisition. The purchase price of the 2012 Senior Notes included $4.8 million of accrued interest for the period from August 15, 2012 to October 25, 2012, which we recorded as interest payable.

The 2012 Senior Notes were offered in a private placement only to qualified institutional buyers under Rule 144A promulgated under the Securities Act of 1933, as amended (the Securities Act), or to persons outside of the United States in compliance with Regulation S promulgated under the Securities Act. The 2012 Senior Notes had terms that were substantially identical to the terms of our 2011 Senior Notes. Pursuant to a registration rights agreement executed as part of the sale of the 2012 Senior Notes, we issued publicly

87

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(8) Indebtedness (continued)

registered additional notes under our 2011 Indenture in exchange for the 2012 Senior Notes. As a result of this exchange offer, 100% in aggregate principal amount of the 2012 Senior Notes was exchanged for the notes under the 2011 Indenture, effective as of June 10, 2013. All of the 8.25% Senior Notes are now issued under the 2011 Indenture, regardless of which private placement they were issued under.

On April 18, 2014, we entered into a supplemental indenture (the Supplemental Indenture) to the 2011 Indenture, by and among us, the guarantors party thereto, and U.S. Bank National Association, as trustee (the 8.25% Senior Notes Trustee), governing our 8.25% Senior Notes. We entered into the Supplemental Indenture after the receipt of consents from the requisite holders of the 8.25% Senior Notes in accordance with the terms and conditions of the Consent Solicitation Statement dated April 7, 2014, pursuant to which Energy XXI had solicited consents (the Consent Solicitation) from the holders of the 8.25% Senior Notes to make certain proposed amendments to certain definitions set forth in the Indenture (the Proposed COC Amendments), as reflected in the Supplemental Indenture. The Consent Solicitation was made as permitted by the Merger Agreement. On April 18, 2014, Energy XXI had received valid consents from holders of an aggregate principal amount of $484.1 million of the 8.25% Senior Notes and those consents had not been revoked prior to the Consent Time. As a result, the requisite holders of the 8.25% Senior Notes had consented to the Proposed COC Amendments, upon the terms and subject to the conditions set forth in the Consent Solicitation Statement. Accordingly, we, the guarantors party thereto and the Trustee entered into the Supplemental Indenture. Subject to the terms and conditions set forth in the Statement, Energy XXI paid an aggregate cash payment equal to $2.50 per $1,000 principal amount of 8.25% Senior Notes for which consents to the Proposed COC Amendments were validly delivered and unrevoked.

On or after February 15, 2015, we may on any one or more occasions redeem all or a part of the 8.25% Senior Notes upon not less than 30 nor more than 60 days notice, at the redemption prices (expressed as percentages of principal amount) set forth below, plus accrued and unpaid interest and special interest, if any, on the notes redeemed, to the applicable date, if redeemed during the twelve-month period beginning on February 15 of the years indicated below, subject to the rights of holders of notes on the relevant record date to receive interest on the relevant interest payment date:

Year	Percentage
2015	104.125 %
2016	102.063 %
2017 and thereafter	100.000 %

Any such redemption and notice may, in our discretion, be subject to the satisfaction of one or more conditions, precedent, including, but not limited to, the occurrence of a change of control. Unless we default in the payment of the redemption price, interest will cease to accrue on the 8.25% Senior Notes or portions thereof called for redemption on the applicable redemption date. In addition, we may, at our option, on any one or more occasions redeem all or a part of the 8.25% Senior Notes prior to February 15, 2015 at a redemption price equal to 100% of the principal amount of the 8.25% Senior Notes redeemed plus a make-whole premium as of, and accrued and unpaid interest to the redemption date.

If we experience a change of control (as defined in the 2011 Indenture), each holder of the 8.25% Senior Notes will have the right to require us to repurchase all or any part (equal to $2,000 or an integral multiple of $1,000 in excess thereof) of the 8.25% Senior Notes at a price in cash equal to 101% of the aggregate principal amount of the 8.25% Senior Notes repurchased, plus accrued and unpaid interest to the date of repurchase. If we engage in certain asset sales, within 360 days of such sale, we generally must use the net cash proceeds from such sales to repay outstanding senior secured debt (other than intercompany debt or any debt owed to an affiliate), to acquire all or substantially all of the assets, properties or capital stock of one or more companies in our industry, to make capital expenditures or to invest in our business. When any such net proceeds that are not so applied or invested exceed $20.0 million, we must make an offer to purchase the

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(8) Indebtedness (continued)

8.25% Senior Notes and other pari passu debt that is subject to similar asset sale provisions in an aggregate principal amount equal to the excess net cash proceeds. The purchase price of each 8.25% Senior Note (or other pari passu debt) so purchased will be 100% of its principal amount, plus accrued and unpaid interest to the repurchase date, and will be payable in cash.

The 2011 Indenture, among other things, limits our ability to: (i) declare or pay dividends, redeem subordinated debt or make other restricted payments; (ii) incur or guarantee additional debt or issue preferred stock; (iii) create or incur liens; (iv) incur dividend or other payment restrictions affecting restricted subsidiaries; (v) consummate a merger, consolidation or sale of all or substantially all of our assets; (vi) enter into sale-leaseback transactions, (vii) enter into transactions with affiliates; (viii) transfer or sell assets; (ix) engage in business other than our current business and reasonably related extensions thereof; or (x) issue or sell capital stock of certain subsidiaries. These covenants are subject to a number of important exceptions and qualifications set forth in the 2011 Indenture.

Prior Senior Credit Facility

On February 14, 2011, we entered into our senior secured credit facility with BMO Capital Markets, as lead arranger, and Bank of Montreal, as administrative agent and a lender, and the other lender parties thereto (as amended and restated, the Prior Senior Credit Facility). The original terms of our Prior Senior Credit Facility established a revolving credit facility with a four-year term that could be used for revolving credit loans and letters of credit up to an aggregate principal amount of $250.0 million. On October 31, 2012, in connection with the Hilcorp Acquisition, through an amendment and restatement of our Prior Senior Credit Facility, the aggregate commitment under this facility was increased to a maximum of $750.0 million and the maturity date was extended to October 31, 2016. The maximum amount of letters of credit that could be outstanding at any one time was $20.0 million. The amount available under the revolving credit facility was limited by the borrowing base. The borrowing base under our Prior Senior Credit Facility had been determined at the discretion of the lenders, based on the collateral value of our proved reserves and was subject to potential special and regular semi-annual redeterminations. On October 31, 2012, the borrowing base under the expanded credit facility was increased from $200.0 million to $425.0 million. On November 26, 2013, we completed our semi-annual redetermination and our borrowing base remained at $425.0 million. In January 2014, our lenders approved a $50.0 million increase in our borrowing base under the $750.0 million facility, increasing our borrowing base to $475.0 million. In addition, in July 2013, our Prior Senior Credit Facility was amended to increase the limit applicable to certain restricted payments permitted by the agreement to accommodate our expanded stock repurchase program. Prior to the Merger, we had increased our borrowings under our Prior Senior Credit Facility to $475.0 million in order to fund the purchase of the SP49 Interests and certain costs associated with the Merger. Immediately prior to the Merger, we had $475 million outstanding under our Prior Senior Credit Facility. As of December 31, 2013, we had $130.0 million outstanding under our Prior Senior Credit Facility. Our Prior Senior Credit Facility was refinanced in connection with the Merger. See Revolving Credit Sub-Facility described below.

The interest rate spread on loans and letters of credit under our Prior Senior Credit Facility was based on the level of utilization and ranged from a base rate plus a margin of 0.75% to 1.75% for base rate borrowings and LIBOR plus a margin of 1.75% to 2.75% for LIBOR borrowings. Commitment fees ranging from 0.375% to 0.50% were payable on the unused portion of the borrowing base.

Revolving Credit Sub-Facility

On June 3, 2014, EGC, EPL, the lenders thereunder and the other parties thereto entered into, entered into the Eighth Amendment dated May 23, 2014 (the Eighth Amendment) to the second amended and restated first lien credit agreement (First Lien Credit Agreement). The Eighth Amendment generally set out the consent of the lenders thereunder to the consummation of the acquisition of EPL by EGC on such date and contained provisions facilitating such acquisition, including providing some of the financing for it. Most of the terms of the Eighth Amendment generally are in regards to incorporating the concept of EPL as a separate borrower for purposes of the First Lien Credit Agreement as described below.

89

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(8) Indebtedness (continued)

Pursuant to the Eighth Amendment, the borrowing base for EGC was established at $1.5 billion until the next redetermination of such borrowing base pursuant to the terms of the First Lien Credit Agreement. Of this borrowing base amount, EGC established a sub-facility pursuant to the Eighth Amendment for us with a borrowing base of $475 million. The maturity date of the revolving credit facility is April 9, 2018, provided that the facility will mature immediately if the EGC 9.25% senior notes are not retired or refinanced by June 15, 2017 or the 8.25% Senior Notes are not retired or refinanced by August 15, 2017. Upon the effectiveness of the Eighth Amendment, we immediately borrowed the entire $475 million to refinance the outstanding indebtedness we had under the terms of our Prior Senior Credit Facility. As a result, on June 3, 2014, we repaid all amounts outstanding under the Prior Senior Credit Facility and our Prior Senior Credit Facility was terminated on June 3, 2014. As of June 30, 2014, we had $475.0 million outstanding under the Eighth Amendment.

The borrowing base for this sub-facility is subject to redetermination from time to time generally on the same basis as is the overall borrowing base under the First Lien Credit Agreement. Under the Eighth Amendment, EGC and its subsidiaries, other than EPL, have guaranteed and secured the indebtedness of EPL and its subsidiaries, but EPL and its subsidiaries have not commensurately guaranteed the obligations of EGC and its other subsidiaries. However, per the terms of the First Lien Credit Agreement, immediately upon our retirement of our obligations in respect of our outstanding 8.25% Senior Notes due 2018, we are required to guarantee and secure the obligations generally of EGC and its subsidiaries and our sub-facility shall terminate and the entire borrowing base amount shall thereupon be available to EGC for credit extensions under the terms of the First Lien Credit Agreement.

Interest accrues and is payable on the EPL sub-facility on the same basis as principal amounts outstanding generally under the First Lien Credit Agreement, which bears interest based on the borrowing base usage, at the applicable LIBOR, plus applicable margins ranging from 1.75% to 2.75% or an alternate base rate, based on the federal funds effective rate plus applicable margins ranging from 0.75% to 1.75%.

On September 5, 2014, we and EGC received written confirmation from the administrative agent under the First Lien Credit Agreement that they had received signature pages from all of the lenders under the First Lien Credit Agreement for the Ninth Amendment to the Second Amended and Restated First Lien Credit Agreement, dated as of September 5, 2014 (the Amendment). The Amendment also became effective as of such date based on satisfaction of the conditions to such effectiveness provided in the Amendment. The Amendment provides for, among other things, an adjustment to the total leverage ratio covenant under the First Lien Credit Agreement as requested by EGC. Under the Amendment, the total leverage of EGC and its consolidated subsidiaries may not exceed 4.25 times the amount of EBITDA of EGC and its consolidated subsidiaries for the fiscal quarters ended June 30, 2014, September 30, 2014, December 31, 2014 and March 31, 2015 and may not exceed 4.00 times the amount of EBITDA for each fiscal quarter ending June 30, 2015 and thereafter. Prior to the Amendment, the total leverage ratio of EGC and its consolidated subsidiaries was required not to exceed 3.50 times EBITDA, although EGC and EPL had obtained a waiver to such requirement for the fiscal quarters ended June 30, 2014 and September 30, 2014 on August 22, 2014. The Amendment also provides for a further covenant of EGC and its subsidiaries to limit the amount of their secured debt to an amount not to exceed 1.75 times the EBITDA of EGC and its consolidated subsidiaries for the fiscal quarters ended

September 30, 2014, December 31, 2014 and March 31, 2015 and 1.50 times EBITDA for any fiscal quarter ending June 30, 2015 and thereafter. Generally, the foregoing amendments under the First Lien Credit Agreement have arisen as EGC continues to consolidate our financial condition and results of operations within the scope of EGC and its subsidiaries.

Pursuant to the terms of the Amendment, the lenders under the First Lien Credit Agreement also maintained the borrowing base for EGC at $1,500,000,000, of which such amount $475,000,000 is the borrowing base for EPL under the sub-facility established for EPL under the First Lien Credit Agreement. These respective borrowing bases were set in accordance with the regular annual process for determination of the borrowing bases and the borrowing bases are to remain effective until the next redetermination thereof under the terms of the First Lien Credit Agreement.

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(9) Concentrations

Significant Customers

We had oil and natural gas sales to three customers accounting for 55%, 23% and 11%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the period from June 4, 2014 through June 30, 2014. We had oil and natural gas sales to three customers accounting for 52%, 23% and 10%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the period from January 1, 2014 through June 3, 2014. We had oil and natural gas sales to three customers accounting for 63%, 24% and 6%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2013. We had oil and natural gas sales to three customers accounting for 45%, 31% and 11%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2012.

Geographic Concentration

Virtually all of our current operations and proved reserves are concentrated in the Gulf of Mexico region. Therefore, we are exposed to operational, regulatory and other risks associated with the Gulf of Mexico, including the risk of adverse weather conditions. We maintain insurance coverage against some, but not all, of the operating risks to which our business is exposed.

(10) Derivative Instruments and Hedging Activities

We enter into derivative instruments to reduce exposure to fluctuations in the price of oil and natural gas for a portion of our production. Our fixed-price swaps fix the sales price for a limited amount of our production and, for the contracted volumes, eliminate our ability to benefit from increases in the sales price of the production. Derivative instruments are carried at their fair value on the consolidated balance sheets as Fair value of commodity derivative instruments. Prior to the Merger, we did not designate derivative instruments as hedges. All gains and losses due to changes in fair market value and contract settlements were recorded in Gain (loss) on derivative instruments in Other income (expense) in the consolidated statements of operations.

Subsequent to the Merger, we designate our derivative financial instruments as cash flow hedges. No components of the cash flow hedging instruments are excluded from the assessment of hedge ineffectiveness. Any gains or losses resulting from the change in fair value from hedging transactions that are determined to be ineffective are recorded as a loss (gain) on derivative financial instruments, whereas gains and losses from the settlement of cash flow hedging contracts are recorded in crude oil and natural gas revenue in the same period during which the hedged transactions are settled. See Note 11 for information regarding fair values of our derivative instruments.

Energy XXI assumed our existing hedges and expects to carry those hedges through the end of contract term beginning from June 2014 through December 2015. Our oil contracts are primarily swaps and benchmarked to Argus-LLS and Brent.

The energy markets have historically been very volatile, and there can be no assurances that crude oil and natural gas prices will not be subject to wide fluctuations in the future. While the use of hedging arrangements helps to limit the downside risk of adverse price movements, they may also limit future gains from favorable price movements.

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(10) Derivative Instruments and Hedging Activities (continued)

The following tables set forth our derivative instruments outstanding as of June 30, 2014 for periods prior to the Merger. Prior to the Merger, we did not elect to designate derivative instruments as hedges.

Oil Contracts

Remaining Contract Term	Fixed-Price Swaps Daily Average Volume (Bbls)	Volume (Bbls)	Average Swap Price ($/Bbl)
July 2014 December 2014	8,769	1,613,550	92.84
January 2015 December 2015	1,500	547,500	97.70

Gas Contracts

Remaining Contract Term	Type of Contract	Volume (Mmbtu)	Average Swap Price ($/Mmbtu)	Weighted Average Contract Price ($/Mmbtu) Sub Floor	Floor	Ceiling
July 2014 December 2014	Three-Way Collars	1,257,000		3.25	4.00	4.76
July 2014 December 2014	Put Spreads	583,000		3.25	4.00	
July 2014 December 2014	Fixed Price Swaps	920,000	4.01			
January 2015 December 2015	Fixed Price Swaps	1,569,500	4.31			

For the period from June 4, 2014 through June 30, 2014, we reclassified from AOCI a loss of approximately $1.6 million to oil and natural gas revenue. The amount expected to be reclassified from other comprehensive income to income in the next 12 months is a gain of $8.8 million ($5.7 million net of tax) on our commodity hedges. The estimated and actual amounts are likely to vary significantly due to changes in market conditions.

The following table presents information about the components of loss on derivative instruments for periods prior to the Merger, during which we did not elect to designate derivative instruments as hedges.

	Period from January 1, 2014 through June 3, 2014	Years Ended December 31, 2013	2012	2011
	(in thousands)			
Change in fair market value	$ 6,996	$ (20,884)	$ (9,491)	$ 11,475
Loss on settlement	(26,416)	(11,477)	(3,814)	(17,345)
Total loss on derivative instruments	$ (19,420)	$ (32,361)	$ (13,305)	$ (5,870)

We monitor the creditworthiness of our counterparties. However, we are not able to predict sudden changes in counterparties creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Possible actions would be to transfer our position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices, and could incur a loss. At June 30, 2014, we had no deposits for collateral with our counterparties.

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(11) Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. ASC Topic 820, Fair Value Measurements and Disclosures, establishes a fair value hierarchy with three levels based on the reliability of the inputs used to determine fair value. These levels include: Level 1, defined as inputs such as unadjusted quoted prices in active markets for identical assets and liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions.

As of June 30, 2014 and December 31, 2013, we held certain financial assets and liabilities that are required to be measured at fair value on a recurring basis, primarily our commodity derivative instruments. We estimate the fair values of these instruments based on published forward commodity price curves, market volatility and contract terms as of the date of the estimate. The discount rate used in the discounted cash flow projections is based on published LIBOR rates. The fair values of commodity derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published issuer-weighted corporate default rates. These price inputs are quoted prices for assets and liabilities similar to those held by us and meet the definition of Level 2 inputs within the fair value hierarchy. The following table sets forth our financial assets and liabilities that are accounted for at fair value on a recurring basis.

	June 30,	December 31,	
	2014	2013	2012
	(in thousands)	(in thousands)	
Assets:			
Current	$	$ 501	$ 3,302
Noncurrent		238	211
Total gross fair value		739	3,513
Less: counterparty set-off		(739)	(3,513)
Total net fair value	$	$	$
Liabilities:			
Current	$ 26,440	$ 29,636	$ 10,026
Noncurrent	2,140	2,136	3,637
Total gross fair value	28,580	31,772	13,663
Less: counterparty set-off		(739)	(3,513)
Total net fair value	$ 28,580	$ 31,033	$ 10,150

The carrying values reported in the consolidated balance sheet for cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short term maturities of these instruments. The fair value for the 8.25% Senior Notes is based on quoted prices, which are Level 1 inputs within the fair value hierarchy. The carrying value of the Senior Credit Facility approximates its fair value because the interest rates are variable and reflective of market rates, which are Level 2 inputs within the fair value hierarchy.

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(11) Fair Value Measurements (continued)

The following table sets forth the carrying values and estimated fair values of our long-term indebtedness.

	June 30, 2014 (In thousands)		December 31, 2013 (In thousands)		December 31, 2012	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
8.25% Senior Notes	$550,566	$545,700	$497,355	$546,338	$494,911	$524,600
Revolving credit sub-facility	475,000	475,000				
Prior Senior Credit Facility			130,000	130,000	195,000	195,000
Total	$1,025,566	$1,020,700	$627,355	$676,338	$689,911	$719,600

Under the successful efforts method of accounting, our assessment of possible impairment of proved oil and natural gas properties was based on our best estimate of future prices, costs and expected net future cash flows by property (generally analogous to a field or lease). An impairment loss was indicated if undiscounted net future cash flows were less than the carrying value of a property. The impairment expense was measured as the shortfall between the net book value of the property and its estimated fair value, which was measured based on the discounted net future cash flows from the property. The inputs used to estimate the fair value of our oil and natural gas properties were based on our estimates of future events, including projections of future oil and natural gas sales prices, amounts of recoverable oil and natural gas reserves, timing of future production, future costs to develop and produce our oil and natural gas and discount factors. These inputs were Level 3 inputs within the fair value hierarchy. Impairments for the year ended December 31, 2013 were primarily related to reservoir performance at a gas well in one of our smaller producing fields. This field was determined to have future net cash flows less than its carrying value resulting in the write down of this property to its estimated fair value. Impairments for the year ended December 31, 2012 were primarily due to the decline in our estimate of future natural gas prices, which affected three of our natural gas producing fields and reservoir performance at two of those fields. These fields were determined to have future net cash flows less than their carrying values resulting in the write downs of these properties to their estimated fair values. We also recorded impairments for undeveloped leases that were expiring in 2013 for which we had no development plans.

As addressed in Note 2, Pushdown Accounting, and Note 3, Acquisitions, we apply fair value concepts in estimating and allocating the fair value of assets acquired and liabilities assumed by Energy XXI in the Merger and assumed in acquisitions in accordance with acquisition accounting for business combinations. The inputs to the estimated fair values of assets acquired and liabilities assumed are described in Notes 2 and 3.

(12) Income Taxes

We are a (U.S.) Delaware company and, as a result of the Merger, a direct subsidiary of EGC. We are a member of a consolidated group of corporations for U.S. federal income tax purposes where Energy XXI, Inc., (the U.S. Parent) is the parent entity. Energy XXI (Bermuda) Limited (the Foreign Parent) indirectly owns 100% of U.S. Parent, but is not a member of the U.S. consolidated group. We operate through our various subsidiaries in the United States as they apply to our current ownership structure. ASC Topic 740 provides that the income tax amounts presented in the separate financial statements of a subsidiary entity that is a member of a consolidated group should be based upon a reasonable allocation of the income tax amounts of that group. We allocate income tax expense/benefit and deferred tax items between affiliates as if each affiliate prepared a separate U.S. income tax return for the reporting period. We have recorded no income tax-related intercompany balances with affiliates.

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(12) Income Taxes (continued)

The components of our income tax provision (reflecting pushdown accounting as described in Notes 1 and 2) are as follows (in thousands):

	Period from June 4, 2014 through June 30, 2014	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	2012	2011
	(In thousands)	(In thousands)			
Current:					
Federal	$	$	$	$	$
State					
Total current	$	$	$	$	$
Deferred:					
Federal	$ (3,574)	$ (4,318)	$ (47,723)	$ (28,719)	$ (14,468)
State		(177)	(1,964)	(1,181)	(354)
Total deferred	$ (3,574)	$ (4,495)	$ (49,687)	$ (29,900)	$ (14,822)
Total:					
Federal	$ (3,574)	$ (4,318)	$ (47,723)	$ (28,719)	$ (14,468)
State		(177)	(1,964)	(1,181)	(354)
Total provision for income taxes.	$ (3,574)	$ (4,495)	$ (49,687)	$ (29,900)	$ (14,822)

The following is a reconciliation of the statutory federal income tax rate to our effective income tax rate:

	Percentage of Pretax Earnings				
	Period from June 4, 2014 through June 30, 2014	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	2012	2011
Statutory federal income tax rate	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %
State taxes		1.4	1.4	1.4	2.3
Non-deductible items		(59.5)			

Change in state tax rate				(2.7)	(1.7)
Statutory depletion			(0.3)	(0.4)	(1.0)
Other		(1.2)	0.7	0.4	1.2
Effective income tax rate	35.0 %	(24.3)%	36.8 %	33.7 %	35.8 %

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(12) Income Taxes (continued)

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of our deferred taxes are detailed in the table below (*in thousands*):

	June 30, 2014	December 31, 2013	2012
	(In thousands)	(In thousands)	
Deferred tax assets:			
Federal and state net operating loss carryforwards	$ 61,546	$ 62,015	$ 62,130
Fair value of commodity derivative instruments	12,136	11,578	3,912
Restricted stock awards and options		3,843	2,313
Percentage depletion carryforward		5,003	4,575
Basis differences in indebtedness	19,651		
Accruals and other	701	1,130	2,613
Deferred tax asset	94,034	83,569	75,543
Deferred tax liabilities:			
Property, plant and equipment, principally due to differences in depreciation	$ 550,435	$ 193,191	$ 136,016
Fair value of commodity derivative instruments		182	214
Prepaid assets	1,663	1,482	1,778
Accruals and other	1,147	2,577	1,907
Deferred tax liabilities	553,245	197,432	139,915
Net deferred tax liability	459,211	113,863	64,372
Reflected in accompanying balance sheets as:			
Current deferred asset	24,587	8,949	3,322
Non-current deferred liability	483,798	122,812	67,694
Total net deferred tax liability	$ 459,211	$ 113,863	$ 64,372

As a result of our reorganization under Chapter 11 in 2009, the income from the discharge of indebtedness, represented for tax purposes as the excess of the principal and accrued interest on the debt discharged over the fair value of the stock of the reorganized company received in exchange for the discharged obligations, as defined by Internal Revenue Code (the IRC) Section 108 (IRC 108), reduced our net operating loss carryforwards (NOLs) by $97 million (Tax Attribute Reduction). Our remaining NOLs as of June 30, 2014 were approximately $191 million.

At June 30, 2014, we had approximately $191 million of federal NOLs, of which approximately $28.8 million relates to excess tax benefits with respect to share-based compensation that have not been recognized in our consolidated financial statements. Our federal NOLs are available to reduce future federal taxable income subject to the limitations and estimates described below and the application of the tax rules and regulations. The NOLs begin expiring in the years 2025 through 2034.

Ownership changes, as defined in IRC Section 382, limit the amount of NOLs that can be utilized annually to offset future taxable income and reduce our tax liability (Section 382 Limitation). In 2009, as part of our Chapter 11 reorganization, we had an ownership change which resulted in a Section 382 Limitation on the amount of NOLs available annually for use. Unused NOLs (those NOLs in existence immediately after the application of IRC 108) totaled $137 million. The annual limitation is approximately $21 million per year beginning in 2010 and, if unused, can be carried over and aggregated with limited NOLs in future years subject to the ultimate expiration of the NOLs. We have not used any limited NOLs since the

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(12) Income Taxes (continued)

reorganization. The amount of limited NOLs available for our 2014 short period federal tax return (for the period ending with the Merger) is approximately $130 million. We believe that we will be able to utilize all of our federal NOLs prior to their expiration.

As of June 30, 2014, our 2010 2014 income tax years remain open to examination by the Internal Revenue Service. However, the statute of limitations for examination of NOLs and other similar attribute carryforwards does not begin to run until the year the attribute is utilized. In some instances, state statutes of limitations are longer than those under U.S. federal tax law. As of the date of these financial statements, our 2013 state income tax returns have not been filed, although management expects to file such returns in a timely manner during 2014. We have no material uncertain tax positions as of June 30, 2014. As of June 30, 2014, there is a cash credit carryforward of $36 thousand.

(13) Employee Benefit Plans

Employee Retention Plans

We have two plans which provide that in the event of termination of employment in connection with a change of control of our company, our officers and employees are entitled to receive a multiple of their salaries and bonuses (typically 1.0 to 2.99 times such amount) and certain other benefits in a lump sum cash payment (the EPL COC Plan). Additionally, all equity awards granted to participants would become fully vested, all stock options would become fully exercisable, and all restrictions on restricted shares and restricted share units would lapse. Upon a change of control, a participant would receive these acceleration benefits regardless of whether the participant s employment was terminated.

The Merger resulted in a change of control pursuant to the EPL COC Plan. During the period January 1, 2014 through June 3, 2014, we recorded approximately $11.9 million for the cost of salaries, bonuses and certain other benefits under the EPL COC Plan. Additionally, in March 2014 the former Compensation Committee established two cash bonus pools under the annual incentive plan to cover the period from January 1, 2014 until the effective date of the Merger. In order to receive such bonus, a participant was required to perform services for the Company through the merger effective date. During the period January 1, 2014 through June 3, 2014, we recorded approximately $5.5 million for the cost of these bonuses.

Share-Based Compensation Plans

In September 2009 the former Board of Directors adopted the 2009 Long Term Incentive Plan (the 2009 LTIP). The purpose of the 2009 LTIP was to provide a means to enhance our profitable growth by attracting and retaining directors, officers and other key employees through affording such individuals a means to acquire and maintain stock ownership or awards the value of which is tied to the performance of our common stock. All directors, officers and other key employees providing services to the Company were potentially eligible to participate in the 2009 LTIP. The

2009 LTIP provided for grants of (i) incentive stock options qualified as such under income tax rules and regulations, (ii) stock options that do not qualify as incentive stock options, (iii) restricted stock awards, (iv) restricted stock units, (v) stock appreciation rights, (vi) bonus stock and awards in lieu of Company obligations, (vii) dividend equivalents in connection with other awards, (viii) deferred shares, (ix) performance units or shares, or (x) any combination of such awards (collectively referred to as Awards). The 2009 LTIP was administered by the former Compensation Committee of our Board of Directors prior to the Merger.

Without stockholder or participant approval, the Board of Directors may amend, alter, suspend, discontinue or terminate the 2009 LTIP or the Compensation Committee s authority to grant awards under the 2009 LTIP, except that any amendment or alteration of the 2009 LTIP, including any increase in any share limitation, shall be subject to the approval of the stockholders not later than the next annual meeting if stockholder approval is required by any state or federal law or regulation or the rules of any stock exchange or automated quotation system on which the common stock may then be listed or quoted.

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(13) Employee Benefit Plans (continued)

On the date of the 2013 Annual Meeting of Stockholders, the stockholders approved an increase in the maximum aggregate number of shares of our common stock that may be issued pursuant to any and all Awards under the 2009 LTIP from 2,474,000 shares to 3,574,000 shares, subject to adjustment due to recapitalization or reorganization, or related to forfeitures or the expiration of Awards, as provided under the 2009 LTIP. As of June 30, 2014, 1,087,347 shares remained available for future grants.

The 2009 LTIP provides for the grant of stock options for which the exercise price, set at the time of the grant, will not be less than the fair market value per share at the date of grant. Stock options granted under the 2009 LTIP generally had a term of 10 years and vested ratably on an annual basis over a three-year period from the date of grant, other than the stock option grant to our former chief executive officer described in the following paragraph.

Pursuant to an employment agreement and the 2009 LTIP, on September 30, 2009, our former chief executive officer was granted an option to purchase 68,116 shares of our common stock, which was memorialized in an option award agreement dated as of October 1, 2009 (the Option Agreement). The terms of the Option Agreement provided for an exercise price equal to $10.00 per share. The closing price of our common stock on the NYSE on September 30, 2009 was $7.46 per share. The option vested ratably on a monthly basis over a 36-month period from the date of grant; however, the vesting for the first six months of the vesting period (the Initial Period) was deferred until the end of the Initial Period and any remaining unvested portion vested ratably on a monthly basis over the remainder of the 36-month vesting period, subject to the executive remaining continuously employed. Under the original terms of the award agreement, vested stock options under the Option Agreement were to expire 30 months following the applicable vesting date of such stock options. On May 1, 2012, the former Compensation Committee modified the terms of the Option Agreement to extend the expiration of the stock options granted thereunder to September 30, 2019, resulting in additional compensation expense of $0.1 million in the year ended December 31, 2012. Upon a change in control as defined in the 2009 LTIP, all stock options under the Option Agreement remain exercisable for a period of not less than 30 months following the change in control.

Prior to February 2014, the former Compensation Committee approved a compensation program for each of our former non-employee directors which provided for the annual grant of a stock award with a market value of $100,000 (as measured on the date of the grant and prorated from the date of the grant, if applicable). In February 2014, the former Compensation Committee approved an increase in the annual grant of a stock award from a market value of $100,000 to a market value of $125,000 (as measured on the date of the grant and prorated from the date of the grant, if applicable) for each of our former non-employee directors. Pursuant to the terms of the program, one-half of each stock award vested immediately on the date of grant, and the remaining one-half vested immediately prior to the next annual meeting of stockholders held after the grant date. The grant date for these awards was typically on the date of our annual meeting of stockholders. Pursuant to this program and the 2009 LTIP, the four members of the former Board of Directors were awarded, in the aggregate, a total of 12,984 shares during the period from January 1, 2014 through June 3, 2014 and a total of 15,305 shares and 31,095 shares during the years ended December 31, 2013 and 2012, respectively. Pursuant to elections made by two directors applicable to certain of these awards, the receipt of such awards totaling 39,009 shares was deferred until such directors ceased to serve on our Board of Directors.

In conjunction with the Merger, each option to purchase shares of Common Stock outstanding immediately prior to the effective date of the Merger under the 2009 LTIP, whether or not then exercisable or vested, was deemed exercised pursuant to a cashless exercise for that number of shares of Common Stock (the net exercise shares) equal to (i) the number of shares of Common Stock subject to such stock option immediately prior to the effective date minus (ii) the number of whole and partial shares of Common Stock subject to such stock option that, when multiplied by $39.00 per share, was equal to the aggregate exercise price of such stock option. Each net exercise share deemed to be an outstanding share of Common Stock

98

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(13) Employee Benefit Plans (continued)

received merger consideration of $39.00 in cash and was not subject to proration like other holders of Common Stock that elected to receive all cash in the Merger.

The following table sets forth our stock option activity for the period from January 1, 2014 through June 3, 2014.

	Options	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contractual Terms	Aggregate Intrinsic Value
			(in years)	(in thousands)
Outstanding on December 31, 2013	1,453,173	$ 17.76		
Granted	143,114	26.79		
Exercised	(1,596,287)	18.57		
Outstanding on June 3, 2014		$		$
Exercisable on June 3, 2014		$		$

The fair value of each stock option award was estimated on the date of grant using the Black-Scholes option valuation model using the weighted average assumptions in the table below.

	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	2012	2011
Black-Scholes option pricing model assumptions:				
Risk free interest rate	2.0 %	1.4 %	1.0 %	1.9 %
Expected life (years)	6.0	6.0	6.0	6.0
Expected volatility	57 %	56 %	56 %	53 %
Dividend yield				

Expected volatility is generally based on the historical volatility of our stock over the period of time equivalent to the expected term of the options granted. As a result of our Chapter 11 reorganization in 2009 for purposes of determining expected volatility in 2014, 2013, and 2012, we included consideration of the historical volatility of the share prices of our peers over the relevant time periods in addition to our historical volatility before, during and after our reorganization. We disregarded our share price for the periods during which our stock price was impacted by factors leading up to the Chapter 11 filing and during the period of the Chapter 11 reorganization proceedings because we did not expect these events to reoccur during the expected term of the options. The expected term of options granted is generally derived from historical exercise patterns over a period of time, with consideration of the expected term of unvested options. However, because we did not have sufficient historical stock option exercise experience upon which to base an estimate of expected term, we used the simplified method for estimating expected term in 2014, 2013, and 2012. The risk-free interest rate was based on the interest rate on constant maturity bonds published by the Federal Reserve with a maturity commensurate with the expected term of the options granted.

The weighted-average grant-date fair value of stock options granted during the period from January 1, 2014 through June 3, 2014, and the years ended December 31, 2013, 2012 and 2011 was $14.57, $14.50, $8.84 and $7.97, respectively. The aggregate intrinsic value (the amount by which the market price of the stock on the date of exercise exceeded the market price of the stock on the date of grant) of stock options deemed exercised or exercised during the period from January 1, 2014 through June 3, 2014, and the years ended December 31, 2013, 2012 and 2011 was $32.6 million, $2.1 million, $0.5 million, and $0.1 million respectively.

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(13) Employee Benefit Plans (continued)

As provided by the EPL COC Plan, in conjunction with the Merger, each outstanding restricted stock award granted by the Company under the 2009 LTIP became fully vested and each holder had the right to make an election to receive the same types of merger consideration that each other holder of Common Stock had the right to receive. The number of shares of the Company s common stock that were issued as a result of the accelerated vesting of prior restricted stock grants totaled 471,080 shares.

The following table sets forth the activity related to our non-vested share awards for the period from January 1, 2014 through June 3, 2014.

	Shares	Weighted-Average Grant-Date Fair Value
Non-vested share awards outstanding at December 31, 2013	444,495	$ 21.98
Granted	161,370	25.08
Vested	(605,865)	22.81
Non-vested share awards outstanding at June 3, 2014		

With the accelerated vesting of all non-vested share awards and the exercise of all outstanding stock options under the EPL COC Plan, all previously unrecognized share-based compensation expense related to these awards was recognized as of June 3, 2014. The following table sets forth share-based compensation expense and related recognized tax benefits.

	Period from January 1, 2014 through June 3, 2014	Year Ended December 31, 2013	2012	2011
Compensation Expense:				
Stock Options	$ 8,248	$ 3,426	$ 2,621	$ 1,497
Non-vested share awards	11,456	3,918	2,096	1,012
Deferred Income Tax Benefit		2,704	1,726	936

The Energy XXI Services, LLC 2006 Long-Term Incentive Plan

Energy XXI maintains an incentive and retention program for their employees. Participation shares (or Restricted Stock Units) are issued from time to time at a value equal to Energy XXI s common share price at the time of issue. The Restricted Stock Units generally vest equally over a three-year period. When vesting occurs, employees are paid an amount equal to the then current common share price times the number of Restricted Stock Units. In conjunction with the Merger, a total of 349,481 Restricted Stock Units were granted to our employees. We recognized compensation expense related to Restricted Stock Units of $0.4 million in the period from June 4, 2014 through June 30, 2014.

401(k) Plan

We also have a 401(k) Plan that covers all employees. We match 100% of each individual participant s contribution not to exceed 6% of the participant s compensation. Our matching contributions are made in cash. For the period from January 1, 2014 through June 30, 2014 and the years ended December 31, 2013, 2012 and 2011, we made matching contributions to the 401(k) Plan of approximately $0.3 million, $0.9 million, $0.8 million and $0.7 million, respectively.

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(14) Commitments and Contingencies

Lease Commitments. We have operating leases for office space and equipment, which expire on various dates through September 2019. Expense relating to operating obligations for the period from June 4, 2014 through June 30, 2014, the period from January 1, 2014 through June 3, 2014, and the years ended December 31, 2013, 2012 and 2011 was $1.7 million, $3.0 million, $7.5 million, $2.4 million and $1.8 million, respectively. Future minimum commitments as of June 30, 2014 under these operating obligations are as follows (in thousands):

2015	$ 1,199
2016	1,231
2017	1,010
2018	542
2019	542
Thereafter	135
Future minimum commitments	$ 4,659

Seismic Commitments. In connection with our exploration and development efforts, we are contractually committed to the acquisition of seismic data in the aggregate amount of $38 million to be incurred over the next three years.

Drilling Rig Commitments. The drilling rig commitments represent minimum future expenditures for drilling rig services. The expenditures for drilling rig services will exceed such minimum amounts to the extent we utilize the drilling rigs subject to a particular contractual commitment for a period greater than the period set forth in the governing contract. As of June 30, 2014, we have entered into five drilling rig commitments:

1) January 1, 2014 to July 15, 2014 at $107,500 per day.

2) February 15, 2014 to August 15, 2014 at $111,380 per day.

3) April 11, 2014 to September 15, 2014 at $112,000 per day.

4) July 1, 2014 to September 1, 2014 at $107,500 per day.

5) September 1, 2014 to October 1, 2014 at $107,500 per day.

Litigation. We are a defendant in a number of lawsuits and are involved in governmental and regulatory proceedings, all of which arose in the ordinary course of business, including, but not limited to, personal injury claims, royalty claims, contract claims, and environmental claims, including claims involving assets owned by acquired companies. While the ultimate outcome and impact on us cannot be predicted with certainty, management believes that the resolution of pending proceedings will not have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

In March and April, 2014, three alleged stockholders (the Plaintiffs) filed three separate class action lawsuits in the Court of Chancery of the State of Delaware on behalf of our stockholders against our Company, our directors, Energy XXI, EGC, and Clyde Merger Sub, Inc., a Delaware corporation and wholly owned subsidiary of EGC (Merger Sub and collectively, the defendants). The Court of Chancery of the State of Delaware consolidated these lawsuits on May 5, 2014. The consolidated lawsuit is styled In re *EPL Oil & Gas Inc. Shareholders Litigation*, C.A. No. 9460-VCN, in the Court of Chancery of the State of Delaware (the lawsuit).

Plaintiffs allege a variety of causes of action challenging the Agreement and Plan of Merger between Energy XXI, EGC, Merger Sub, and EPL (the Merger Agreement), including that (a) our directors have allegedly breached fiduciary duties in connection with the Merger and (b) we along with Energy XXI, EGC, and Merger Sub, allegedly aided and abetted in these alleged breaches of fiduciary duties. Plaintiffs causes of

101

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(14) Commitments and Contingencies (continued)

action are based on their allegations that (i) the Merger allegedly provided inadequate consideration to our stockholders for their shares of our common stock; (ii) the Merger Agreement contained contractual terms including, among others, the (A) no solicitation, (B) competing proposal, and (C) termination fee provisions that allegedly dissuaded other potential acquirers from making competing offers for shares of our common stock; (iii) certain of our officers and directors allegedly received benefits including (A) an offer for one of our directors to join the Energy XXI board of directors and (B) the triggering of change-in-control provisions in notes held by our executive officers that were not equally shared by our stockholders; (iv) Energy XXI required our officers and directors to agree to vote their shares of our common stock in favor of the Merger; and (v) we provided, and Energy XXI obtained, non-public information that allegedly allowed Energy XXI to acquire us for inadequate consideration. Plaintiffs also allege that the Registration Statement filed on Form S-4 by us and Energy XXI on April 1, 2014 omits information concerning, among other things, (i) the events leading up to the Merger, (ii) our efforts to attract offers from other potential acquirors, (iii) our evaluation of the Merger; (iv) negotiations between us and Energy XXI, and (v) the analysis of our financial advisor. Based on these allegations, plaintiffs seek to have the Merger agreement rescinded. Plaintiffs also seek damages and attorneys fees.

Defendants date to answer, move to dismiss, or otherwise respond to the lawsuit has been indefinitely extended. We cannot predict the outcome of the lawsuit or any others that might be filed subsequent to the date of the filing of this Transition Report; nor can we predict the amount of time and expense that will be required to resolve the lawsuit. The defendants intend to vigorously defend the lawsuit.

Other. We maintain restricted escrow funds in a trust for future abandonment costs at our East Bay property. The trust was originally funded with $15.0 million and, with accumulated interest, increased to $16.7 million at December 31, 2008. We may draw from the trust upon completion of qualifying abandonment activities at our East Bay field. At June 30, 2014, we had $6.0 million remaining in restricted escrow funds for decommissioning work in our East Bay field, which will remain restricted until substantially all required decommissioning in the East Bay field is complete. Amounts on deposit in the trust account are reflected in Restricted cash on our consolidated balance sheets.

We record liabilities when we deliver production that is in excess of our interest in certain properties. In addition to these imbalances, we may, from time to time, be allocated cash sales proceeds in excess of amounts that we estimate are due to us for our interest in production. These allocations may be subject to further review, may require more information to resolve or may be in dispute. In July 2010, we were notified by a purchaser of oil production from one of our non-operated fields that we were allocated, and received sales proceeds from, more oil production than we actually sold to that purchaser. The oil purchaser s initial estimate of the oil volumes misallocated to us was approximately 74,000 barrels, which may have been valued at up to $6.9 million based on information provided by the oil purchaser. We had previously recorded an amount that we believed may have been payable related to a potential reallocation, which amount was reflected in Accrued expenses in the accompanying consolidated balance sheet as of December 31, 2012. In connection with the sale of the BM Interests in 2013, the buyer assumed any liability we may have had related to this matter.

We and our oil and gas joint interest owners are subject to periodic audits of the joint interest accounts for leases in which we participate and/or operate. As a result of these joint interest audits, amounts payable or receivable by us for costs incurred or revenue distributed by the operator or by us on a lease may be adjusted, resulting in adjustments, increases or decreases, to our net costs or revenues and the related cash flows. Such adjustments may be material. When they occur, these adjustments are recorded in the current period, which generally is one or more years after the related cost or revenue was incurred or recognized by the joint account.

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(15) Related Party Transactions

On June 3, 2014 we acquired from Energy XXI GOM the SP49 Interests located in the Gulf of Mexico for $230.0 million, subject to customary adjustments to reflect an economic effective date of June 1, 2014. As a result of the SP49 Acquisition, we have become the sole working interest owner of the South Pass 49 field. We financed the SP49 Acquisition with borrowings of approximately $135 million under our Prior Senior Credit Facility and a $95 million capital contribution from EGC. See Note 3, Acquisitions and Dispositions for more information.

(16) Comparative Period Information

The following tables present certain financial information for the six months ended June 30, 2014 and 2013, respectively. As more fully described in Note 1, Organization and Summary of Significant Accounting Policies Basis of Presentation, due to our new basis of accounting resulting from the Merger, financial information for periods prior to the Merger is not comparable to such information for periods subsequent to the Merger.

	Period from June 4, 2014 through June 30, 2014	Period from January 1, 2014 through June 3, 2014	Six Months Ended June 30, 2013 (Unaudited)
	(in thousands)	(in thousands)	
Total revenue	$ 60,143	$ 276,400	$ 366,436
Income from operations	13,834	23,563	158,244
Income (loss) before income taxes	10,211	(18,461)	155,057
Deferred income tax expense	(3,574)	(4,495)	(56,441)
Net income (loss)	$ 6,637	$ (22,956)	$ 98,616
Basic earnings (loss) per share		$ (0.59)	$ 2.51
Diluted earnings (loss) per share		$ (0.59)	$ 2.48
Weighted average common shares used in computing earnings (loss) per share:			
Basic		38,730	38,847
Diluted		38,730	39,302

	Period from June 4,	Period from January 1,	Six Months Ended

	2014 through June 30, 2014	2014 through June 3, 2014	June 30, 2013 (Unaudited)
	(in thousands)	(in thousands)	
Net cash provided by operating activities	$ 22,209	$ 105,122	$ 192,476
Net cash used in investing activities	(200,929)	(258,714)	(154,969)
Net cash provided by (used in) financing activities	(15,729)	344,830	(35,143)
Net increase (decrease) in cash and cash equivalents	(194,449)	191,238	2,364
Cash and cash equivalents at beginning of period	200,050	8,812	1,521
Cash and cash equivalents at end of period	$ 5,601	$ 200,050	$ 3,885

103

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(17) Interim Financial Information (Unaudited)

The following tables summarize our consolidated unaudited interim financial information for the six months ended June 30, 2014 and the year ended December 31, 2013.

	Three Months Ended March 31[1]	Period from April 1 through June 3[2]	Period from June 4 through June 30
	(In thousands, except per share data)		(In thousands)
2014			
Revenues	$ 159,491	$ 116,909	60,143
Costs and expenses	112,095	140,742	46,309
Income (loss) from operations	47,396	(23,833)	13,834
Net income (loss)	13,331	(36,287)	6,637
Earnings (loss) per share:			
Basic	$ 0.34	$ (0.94)	
Diluted	0.34	(0.94)	

(1) Included in costs and expenses for the three months ended March 31, 2014 are merger related costs totaling $2.2 million.

(2) Included in costs and expenses for the period from April 1, 2014 through June 3, 2014 are merger related costs totaling $43.5 million.

	Three Months Ended			
	March 31	June 30	September 30[1]	December 31[2]
	(In thousands, except per share data)			
2013				
Revenues	$ 182,349	$ 184,087	$ 183,992	$ 142,610
Costs and expenses	109,657	98,535	143,178	122,077
Income from operations	72,692	85,552	40,814	20,533
Net income (loss)	29,037	69,579	(1,284)	(12,058)
Earnings (loss) per share:				
Basic	$ 0.74	$ 1.77	$ (0.03)	$ (0.31)
Diluted	0.73	1.75	(0.03)	(0.31)

(1)

Included in net income (loss) for the three months ended September 30, 2013 is the loss on abandonment activities totaling $22.6 million resulting from an increase in required scope of work attributable to changes in regulatory interpretations and enforcement by BSEE in the deepwater.

(2) The decrease in revenue for the quarter ended December 31, 2013 compared to the quarter ended September 30, 2013 is primarily due to a decrease in oil production and a decrease in the average selling prices of our oil.

(18) Supplementary Oil and Natural Gas Disclosures (Unaudited)

Our estimates of proved reserves are based on a reserve report prepared as of June 30, 2014 by the independent petroleum engineering firm Netherland, Sewell & Associates, Inc. Users of this information should be aware that the process of estimating quantities of proved and proved developed natural gas and crude oil reserves is very complex, requiring significant professional judgment in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(18) Supplementary Oil and Natural Gas Disclosures (Unaudited) (continued)

under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the professional judgment required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. Proved reserves are estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

The following table sets forth our estimated net proved reserves, changes in our estimated net proved reserves and our net proved developed and undeveloped reserves.

	Oil (Mbbls)	Gas (Mmcf)	Oil Equivalent (Mboe)
Estimated Proved Reserves:			
December 31, 2011	27,301	58,785	37,099
Acquisitions[a]	16,430	115,876	35,742
Extensions and discoveries[b]	6,388	10,241	8,095
Revisions	1,128	4,033	1,800
Production	(3,805)	(8,996)	(5,304)
December 31, 2012	47,442	179,939	77,432
Acquisitions	366	209	401
Sales	(1,415)	(916)	(1,568)
Extensions and discoveries[c]	7,354	20,247	10,729
Revisions	3,952	(10,128)	2,264
Production	(6,182)	(15,767)	(8,810)
December 31, 2013	51,517	173,584	80,448
Acquisitions[d]	11,640	32,731	17,095
Extensions and discoveries[e]	418	5,352	1,310
Revisions[f]	386	(34,791)	(5,413)
Production	(3,129)	(4,795)	(3,928)
June 30, 2014	60,832	172,081	89,512
Proved developed reserves:			
December 31, 2012	37,908	120,687	58,022
December 31, 2013	39,439	107,687	57,387

June 30, 2014	45,232	101,361	62,126
Proved undeveloped reserves:			
December 31, 2012	9,534	59,252	19,409
December 31, 2013	12,078	65,897	23,061
June 30, 2014	15,600	70,720	27,386

105

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(18) Supplementary Oil and Natural Gas Disclosures (Unaudited) (continued)

(a) Reserves acquired in the acquisitions of the Hilcorp Properties and the ST41 Interests.

(b) Includes extensions and discoveries across 6 different fields, primarily within our West Delta and Ship Shoal areas. These extensions and discoveries added volumes ranging from 18 Mboe to 1.2 Mmboe each, with three exceeding 1.0 Mmboe each.

(c) Includes extensions and discoveries across 12 different fields, primarily within our Ship Shoal and West Delta areas. The Ship Shoal 208 field accounts for 46% of our total extensions and discoveries with 4,973 Mboe, consisting of 3,967 Mbbls of oil and 6,035 Mmcf of produced gas. The remaining 11 locations account for up to 16% each of total extensions and discoveries with reserves ranging from 10 Mboe to 1.6 Mmboe.

(d) Reserves acquired in the acquisitions of the EI Interests and the SP49 Interests.

(e) Includes extensions and discoveries across 3 different fields, primarily within our West Delta, Ship Shoal and Eugene Island areas. The West Delta field accounts for 68% of our total extensions and discoveries with 890 Mboe, consisting of 50 Mbbls of oil and 5,040 Mmcf of natural gas. The Ship Shoal 208 field accounts for approximately 23% of our total extensions and discoveries with 295 Mboe, consisting of 260 Mbbls of oil and 212 Mmcf of natural gas.

(f) Natural gas revisions also include negative revisions of approximately 35,976 Mmcf related to the exclusion of estimated fuel gas in our natural gas reserves in the June 30, 2014 reserve volumes. This change in methodology reflects fuel gas as negative natural gas reserves rather than a production cost and does not impact future net cash flows after income taxes or standardized measure of discounted future net cash flows. The negative revisions related to this change in the fuel gas methodology were partially offset by increases of approximately 1,185 Mmcf associated with improved performance of certain wells.

Capitalized costs for oil and natural gas producing activities consist of the following:

	June 30, 2014 (In thousands)
Proved properties	$ 2,316,306
Unevaluated properties	908,483
Accumulated depreciation, depletion and amortization	(22,689)
Net capitalized costs	$ 3,202,100

	2013 (In thousands)
Proved properties	$ 2,307,891
Unproved properties	39,191

Accumulated depreciation, depletion and amortization	(614,068)
Net capitalized costs	$ 1,733,014

The following table sets forth the costs incurred associated with finding, acquiring and developing our proved oil and natural gas reserves.

	Six Months Ended June 30, 2014	Year Ended December 31, 2013	2012	2011
	(In thousands)			
Acquisitions Proved[(1)]	$ 314,169	$ 46,047	$ 706,322	$ 261,812
Acquisitions Unproved	9,503	2,200	7,496	14
Exploration	56,079	46,100	43,338	17,129
Development[(2)]	242,217	303,245	180,938	83,577
Costs incurred	$ 621,968	$ 397,592	$ 938,094	$ 362,532

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(18) Supplementary Oil and Natural Gas Disclosures (Unaudited) (continued)

(1) For the six months ended June 30, 2014, includes $231 million associated with the acquisition of the SP 49 Interests and $83 million associated with the acquisition of the EI Interests. See Note 3 Acquisitions and Dispositions of the consolidated financial statements in Part II, Item 8 of this Transition Report for further information.

(2) Includes our estimates during the years ended December 31, 2013, 2012 and 2011 of incurred asset retirement obligations associated with finding and developing our proved oil and natural gas reserves of $1.2 million, $1.2 million and $0.2 million, respectively.

Expenditures incurred for exploratory dry holes are included in investing activities in the consolidated statements of cash flows.

Standardized Measure of Discounted Future Net Cash Flows Relating to Reserves

The following information has been developed utilizing procedures prescribed by ASC 932. It may be useful for certain comparative purposes, but should not be solely relied upon in evaluating our performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of our oil and natural gas reserves or the current value of the Company.

We believe that the following factors should be taken into account in reviewing the following information: (1) future costs and sales prices are likely to differ materially from those required to be used in these calculations; (2) due to future market conditions, governmental regulations and other factors, actual rates of production achieved in future years may vary significantly from the rate of production assumed in the calculations; (3) the use of a 10% discount rate, while mandated under ASC 932, is arbitrary and may not be reasonable as a measure of the relative risk inherent in realizing future net oil and gas revenues; and (4) future net revenues may be subject to different rates of income taxation.

The Standardized Measure of Discounted Future Net Cash Flows uses future cash inflows estimated using oil and natural gas prices computed by applying the use of physical pricing based on the simple average of the closing price on the first day of each of the twelve months during the fiscal year (as required by ASC 932) and by applying historical adjustments, including transportation, quality differentials, and purchaser bonuses, on an individual property basis, to the year-end quantities of estimated proved reserves. The historical adjustments applied to the computed prices are determined by comparing our historical realized price experience with the comparable historical market, or posted, price. These adjustments can vary significantly over time both in amount and as a percentage of the posted price, especially related to our oil prices during periods when the market price for oil varies widely. The price adjustments reflected in our computed reserve prices may not represent the amount of price adjustments we may actually obtain in the future when we sell our production, nor do they give effect to any hedging transactions that we may enter into. Future cash inflows were reduced by estimated future development, abandonment and production costs based on period-end costs with the assumption of the continuation of existing economic conditions in order to arrive at net cash flows before tax. Future income tax expense has been computed by applying period-end statutory tax rates to aggregate future net cash flows, reduced by the tax basis of the properties involved and tax carryforwards. Use of a 10% annual discount rate in computing Standardized Measure of Discounted Future Net Cash Flows is required by ASC 932.

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(18) Supplementary Oil and Natural Gas Disclosures (Unaudited) (continued)

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

	June 30, 2014	December 31, 2013
	(In thousands)	
Future cash inflows	$6,704,859	$5,937,536
Future production costs	(2,126,110)	(1,957,868)
Future development costs(1)	(1,161,289)	(1,085,440)
Future income taxes	(712,700)	(641,536)
Future net cash flows after income taxes	2,704,760	2,252,692
10% annual discount for estimated timing of cash flows	(740,167)	(603,614)
Standardized measure of discounted future net cash flows	$1,964,593	$1,649,078

(1) Future development cost as of June 30, 2014 include $558.4 million of estimated abandonment and decommissioning costs, net of $120.5 million of estimated salvage values. Future development costs as of December 31, 2013, include $569.9 million of estimated abandonment and decommissioning costs, net of $25.8 million of estimated salvage values.

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved oil and natural gas reserves for the six months ended June 30, 2014 and the year ended December 31, 2013 is as follows:

	Six Months Ended June 30, 2014	Year Ended December 31, 2013
	(In thousands)	
Beginning of the period	$1,649,078	$1,574,282
Sales and transfers of oil and natural gas produced, net of production costs	(240,361)	(513,906)
Net changes in prices and production costs(1)	(21,599)	96,751
Purchase of minerals in place	471,329	26,708
Sales of minerals in place		(64,539)
Extensions, discoveries and improved recoveries, net of future production costs	49,566	363,493
Revision of quantity estimates	(325,294)	84,490

Previously estimated development costs incurred during the period	55,888	33,920
Changes in estimated future development costs	1,560	18,229
Changes in production rates (timing) and other	170,915	(113,022)
Accretion of discount	210,932	197,927
Net change in income taxes	(57,421)	(55,255)
Net increase	315,515	74,796
End of period	$1,964,593	$1,649,078

(1) Our estimated future production costs reflect a decrease related to the previously described change in the fuel gas methodology to reflect fuel gas as negative natural gas reserves rather than as production cost.

108

TABLE OF CONTENTS

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(18) Supplementary Oil and Natural Gas Disclosures (Unaudited) (continued)

At June 30, 2014 and December 31, 2013, the computation of the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves was based on the following computed prices:

	2014	2013
per barrel of oil	$ 98.58	$ 105.30
per Mcf for natural gas	$ 4.12	$ 3.73

(19) Supplemental Condensed Consolidating Financial Information

In connection with issuing the 8.25% Senior Notes described in Note 8, all of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries) each of which is 100% owned by EPL (the Guarantor Subsidiaries) jointly and severally guaranteed the payment obligations under our 8.25% Senior Notes. The guarantees are full and unconditional, as those terms are used in Rule 3-10 of Regulation S-X, except that a Guarantor Subsidiary can be automatically released and relieved of its obligations under certain customary circumstances contained in the 2011 Indenture. So long as other applicable provisions of the indenture are adhered to, these customary circumstances include: when a Guarantor Subsidiary is declared unrestricted for covenant purposes, when the requirements for legal defeasance or covenant defeasance or to discharge the indenture have been satisfied, or when the Guarantor Subsidiary is sold or sells all of its assets. The following supplemental financial information sets forth, on a consolidating basis, the balance sheets, statements of operations and cash flow information for EPL (Parent Company Only) and for the Guarantor Subsidiaries. We have not presented separate financial statements and other disclosures concerning the Guarantor Subsidiaries, or for any individual Guarantor Subsidiary, because management has determined that such information is not material to investors.

The supplemental condensed consolidating financial information has been prepared pursuant to the rules and regulations for condensed financial information and does not include all disclosures included in annual financial statements. Certain reclassifications were made to conform all of the financial information to the financial presentation on a consolidated basis. The principal eliminating entries eliminate investments in subsidiaries, intercompany balances and intercompany revenues and expenses.

TABLE OF CONTENTS

SUCCESSOR COMPANY
Supplemental Condensed Consolidating Balance Sheet
As of June 30, 2014

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
ASSETS				
Current assets:				
Cash and cash equivalents	$5,601	$	$	$5,601
Trade accounts receivable net	72,156	145		72,301
Intercompany receivables		26,311	(26,311)	
Fair value of commodity derivative instruments				
Deferred tax asset	24,587			24,587
Prepaid expenses	26,521			26,521
Total current assets	128,865	26,456	(26,311)	129,010
Net property and equipment	3,034,805	170,382		3,205,187
Investment in affiliates	126,638		(126,638)	
Goodwill	327,235			327,235
Restricted cash	6,023			6,023
Fair value of commodity derivative instruments				
Deferred financing costs				
Other assets	226	91		317
Total assets	$3,623,792	$196,929	$(152,949)	$3,667,772
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities:				
Accounts payable	$90,267	$656	$	$90,923
Intercompany payables	26,311		(26,311)	
Accrued expenses	161,503	15		161,518
Asset retirement obligations	33,357	6,474		39,831
Fair value of commodity derivative instruments	26,440			26,440
Due to EGC	4,960			4,960
Total current liabilities	342,838	7,145	(26,311)	323,672
Long-term debt	1,025,566			1,025,566
Asset retirement obligations	193,908	38,956		232,864
Deferred tax liabilities	459,608	24,190		483,798
Fair value of commodity derivative instruments	2,140			2,140
Other	6			6
Total liabilities	2,024,066	70,291	(26,311)	2,068,046
Stockholders equity:				
Preferred stock				

Common stock				
Additional paid-in capital	1,599,341	85,479	(85,479)	1,599,341
Accumulated other comprehensive income	(6,252)			(6,252)
Treasury stock, at cost				
Retained earnings	6,637	41,159	(41,159)	6,637
Total stockholders equity	1,599,726	126,638	(126,638)	1,599,726
Total liabilities and stockholders equity	$3,623,792	$196,929	$(152,949)	$3,667,772

110

TABLE OF CONTENTS

PREDECESSOR COMPANY
Supplemental Condensed Consolidating Balance Sheet
As of December 31, 2013

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
ASSETS				
Current assets:				
Cash and cash equivalents	$ 8,812	$	$	$ 8,812
Trade accounts receivable net				