Cobalt International Energy

2015 ANNUAL REPORT

A DECADE OF DISCOVERY

2005 – 2015

ABOUT COBALT

Cobalt's vision is to be *"One of the World's Most Admired E&P Companies"* by adhering to our values, achieving promised results and consistently delivering top quartile rates of return.

OUR VALUES

COMMITMENT TO HEALTH, SAFETY, SECURITY AND ENVIRONMENT

Apply the highest level health, safety, security and environmental standards in everything we do

FOCUS ON SHAREHOLDER VALUE

Focus all our decisions to deliver the greatest value to our shareholders and investors

SUPERIOR TALENT, TEAM AND RESOURCES

Attract and leverage world class talent, team and resources, bringing together our core competencies for excellence

ACTION ORIENTED AND RESULTS FOCUSED

Action driven with thoughtful analysis, nimbleness, and efficiency to achieve results

LEGENDARY LEADERSHIP AND ENTREPRENEURSHIP

Be renowned leaders who navigate a strategy for high performance and entrepreneurship

OPERATE WITH INTEGRITY

Work with the highest levels of integrity, being trustworthy as partners and as colleagues

SOCIALLY AND PROFESSIONALLY REWARDING

Provide a positive productive work environment for great ideas to incubate and where significant contributions lead to substantial rewards

Cobalt International Energy, Inc. (NYSE: CIE) is a publicly traded independent exploration and production company (E&P) which was formed in 2005 and is headquartered in Houston, Texas.

Over the last decade, we have executed the strategy on which the Company was founded: Deepwater oil, early entry positions, material assets, superior people and technology, focus and a strong balance sheet. We have built a carefully selected, enviable portfolio of assets in the deepwater regions of the U.S. Gulf of Mexico and offshore West Africa.

Our operations currently focus in the deepwater U.S. Gulf of Mexico. In January 2016, we achieved initial production of oil and gas from the Heidelberg field. Our exploration efforts in the U.S. Gulf of Mexico have resulted in four oil and gas discoveries including the North Platte, Shenandoah, Anchor, and Heidelberg fields, each of which are in various stages of appraisal and development. We also have a non-operated interest in the Diaba Block offshore Gabon.

COBALT INTERNATIONAL ENERGY, INC.

In November 2015, we celebrated Cobalt's tenth anniversary of its founding. During the past ten years, Cobalt's explorers have been some of the most successful in the world through discoveries of large accumulations of oil and gas in the Inboard Lower Tertiary trend in the U.S. Gulf of Mexico and in the Kwanza Basin offshore Angola.

While we have faced and overcome many challenges over the past ten years, today we are confronted by the challenges presented by the prolonged downturn in oil and gas prices. We are aggressively working to reduce our cost structure company-wide and position ourselves to withstand a continued period of low oil and gas prices.

As we reflect upon past success, we are also looking to take advantage of the exciting opportunities that the current environment presents for Cobalt.

LETTER TO SHAREHOLDERS

Joseph H. Bryant
Chairman and Chief Executive Officer

Reflecting back on the past year, it is clear that 2015 was a transformative year for Cobalt. In August 2015, we entered into an agreement to sell our Angola business to Sonangol for $1.75 billion. This pending transaction represents a strategic change in our business to focus almost entirely on the deepwater Gulf of Mexico. We believe the deepwater Gulf of Mexico has, and will continue to have the potential for, some of the best oil and gas resources in the world.

The Gulf of Mexico has some of the world's largest oil accumulations, and combined with long-lived production profiles, leading edge technology, existing infrastructure and relatively stable fiscal terms, the Gulf of Mexico should continue to attract a significant amount of investment and represent a sizeable source of oil and gas supplies worldwide for years to come.

Shifting to a discussion of our 2015 operational results, appraisal operations at North Platte, Anchor and Shenandoah were all successful. At North Platte, we drilled our first appraisal well which encountered over 550 feet of net oil pay, but with evidence of even better developed reservoirs than seen in the discovery well. We subsequently drilled a sidetrack appraisal well at North Platte, which encountered approximately 500 feet of net oil pay and exhibited some of the best rock and reservoir properties that we have seen in the Inboard Lower Tertiary trend of the Gulf of Mexico. At Shenandoah, the second appraisal well found an expanded geologic reservoir section and confirmed excellent reservoir qualities. A sidetrack of the third appraisal well at Shenandoah encountered over 600 feet of net oil pay. The next appraisal well at Shenandoah is on tap for 2016, and is designed to confirm and extend the reservoir boundaries. At Anchor, the initial exploration well encountered nearly 700 feet of net oil pay. In the second half of 2015, an appraisal sidetrack well was drilled down dip to delineate the Anchor discovery well. The appraisal well encountered 694 feet of net oil pay in a hydrocarbon column of at least 1,800 feet in Inboard Lower Tertiary reservoirs. We are currently participating in the Anchor #3 appraisal well and expect to have results sometime in the second half of this year. As these appraisal operations have shown, we believe our current Gulf of Mexico assets in appraisal and development are extremely attractive and will position Cobalt well for future success.

Another significant milestone occurred in January 2016, when we achieved our first production and revenue, as the Heidelberg field commenced initial oil and gas

production ahead of schedule and within budget. Two additional development wells are planned to be drilled and completed at Heidelberg in 2016 with the goal to increase its production over time.

Of course, any overview of 2015 would not be complete without a discussion of the impact that the severe and prolonged downturn in oil and gas prices has had on our company and the oil and gas industry as a whole. Any price displacement of the magnitude that we have seen creates both challenges and opportunities. The first challenge we faced was to review our cost structure and reduce it to a level commensurate with current oil and gas prices. To that end, we worked diligently with our equipment and service providers and through our initial efforts, we have been able to reduce our non-rig drilling costs in the Gulf of Mexico by 25%. Our work is not finished here. We will continue to do all we can to drive down costs to protect our balance sheet and ensure that Cobalt is a strong and durable enterprise for years to come. Despite the negative effects the current price environment has had on our business and the performance of our stock price, I am confident and optimistic in Cobalt's future. While I can make no assurances regarding the Angola transaction, the proceeds we receive upon closing should allow us to take advantage of attractive investment opportunities in today's market for deepwater oil and gas assets. The downturn has also presented us with the opportunity to appraise and develop our current discovered oil and gas resources at lower costs while hopefully bringing these projects online at a future point in time in which oil and gas prices are much higher than today.

In November 2015, Cobalt celebrated its tenth anniversary. As I reflect on Cobalt's ten year history, I am proud of all that we have accomplished but excited about the future of our company. I recognize that today's oil and gas price headwinds present challenges that we must continue to overcome. However, I am confident that we can and will face these challenges head on and emerge as a stronger, sustainable and more resilient company.

On behalf of the Board of Directors and our entire team, thank you for your continued confidence in and support of Cobalt.

Joseph H. Bryant
Chairman and
Chief Executive Officer

"AS I REFLECT ON COBALT'S TEN YEAR HISTORY, I AM PROUD OF ALL THAT WE HAVE ACCOMPLISHED BUT EXCITED ABOUT THE FUTURE OF OUR COMPANY."

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OUR CONTINUED COMMITMENT
TO THE DEEPWATER GULF OF MEXICO

- » Significant oil potential
- » The world's technology proving ground
- » Existing infrastructure
- » Stable fiscal terms and mature regulatory system
- » Cobalt's assets attractive even in today's environment
- » Cobalt advantaged with proven core competencies
- » ~1.3 million acres leased; ~90% Cobalt-operated

OUR SIGNIFICANT COST SAVINGS AND EFFICIENCY IMPROVEMENTS

- » Substantial well cost and drilling efficiency improvements realized to date
  - ~25% reduction in non-rig rate drilling costs in the Gulf of Mexico
  - Improved drilling efficiency; North Platte sidetrack coming in at ~60% of pre-drill cost estimate
  - General and Administrative to benefit from organizational restructuring
- » Continued focus on further improvements as costs become better aligned with lower oil prices

2015 FINANCIAL HIGHLIGHTS

Results of Operations from Continuing Operations

We operate our business in the U.S. Gulf of Mexico and Gabon, West Africa. The discussion of the results of operations and the period-to-period comparisons presented below for consolidated operations analyzes our historical results and does not include any results of operations from our Angola assets, which are currently classified as assets held for sale pending the closing of the Angola Transaction. The following discussion may not be indicative of future results.

Fiscal Year ended December 31, 2015 as compared to year ended December 31, 2014:

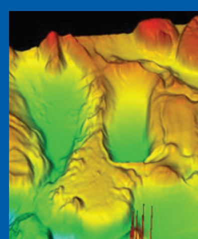
	Year Ended December 31, 2015	Year Ended December 31, 2014	Increase (Decrease)	Percentage Change
	($ in thousands)			
Consolidated Operations:				
Oil and gas revenue	$ —	$ —	$ —	—%
Operating costs and expenses				
Seismic and exploration	45,318	41,431	3,887	9%
Dry hole expense and impairment	308,960	133,223	175,737	132%
General and administrative	87,031	72,090	14,941	21%
Accretion expense	99	—	99	100%
Depreciation and amortization	1,403	1,694	(291)	(17)%
Total operating costs and expenses	**442,811**	**248,438**	**194,373**	**78%**
Operating income (loss)	**(442,811)**	**(248,438)**	**(194,373)**	**78%**
Other income (expense)				
Gain (loss) on sale of assets	1,555	—	1,555	100%
Interest income	6,087	5,958	129	2%
Interest expense	(63,376)	(74,768)	11,392	(15)%
Total other income (expense)	**(55,734)**	**(68,810)**	**13,076**	**(19)%**
Net income (loss) from continuing operations before income tax	**(498,545)**	**(317,248)**	**(181,297)**	**57%**
Income tax expense (benefit)	—	—	—	—
Net income (loss) from continuing operations	**$ (498,545)**	**$ (317,248)**	**$ (181,297)**	**57%**

A DECADE OF DISCOVERY

05

Cobalt formed as new deepwater exploration and production company with backing from private equity sponsors including Goldman, Sachs & Co. and Carlyle Riverstone

06

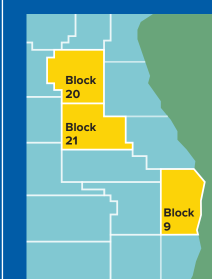


Mapped Angola deepwater pre-salt play as a potential new exploration basin; Reviewed pre-salt play concept with Sonangol

Awarded 23 Gulf of Mexico lease blocks in OCS Lease Sale; Further private equity investment from KERN Partners, Ltd.

07

Third most successful bidder in OCS Lease Sale with 53 high bids; Awarded 51 Gulf of Mexico lease blocks



Obtained contractual rights to Angolan acreage; Additional private equity investment from First Reserve Corporation

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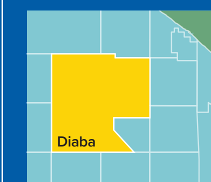

Acquired interest in Gabon Diaba Block from TOTAL

Awarded 36 Gulf of Mexico lease blocks at Central Lease Sale

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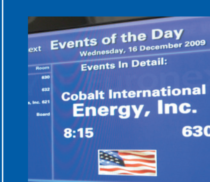
Heidelberg Miocene discovery (GC 859); Shenandoah Inboard Lower Tertiary discovery (WR 52); TOTAL Alliance established in Gulf of Mexico



Completed successful Initial Public Offering, raising over $1 Billion

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Signed Risk Services Agreements for Blocks 9/09 & 21/09

Entered into long-term rig contracts for Ocean Confidence in Angola and Ensco 8503 in deepwater Gulf of Mexico

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Drilled successful Heidelberg appraisal well (GC 903)

Commenced drilling Cameia deepwater pre-salt well in Block 21/09; Signed Production Sharing Contract for Block 20/11

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Cameia pre-salt discovery (Block 21/09); Drilled successful Cameia appraisal well

North Platte Inboard Lower Tertiary discovery (GB 959)

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Sanctioned Heidelberg and booked Cobalt's first proved reserves; Drilled successful Shenandoah-2 appraisal well (WR 51)

Lontra pre-salt discovery (Block 20/11); Mavinga pre-salt discovery (Block 21/09); First pre-salt discovery in Gabon with Diaman 1B (Diaba Block)

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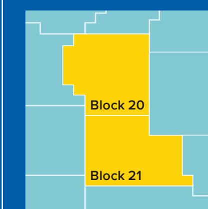

First pre-salt syn-rift discovery at Bicuar (Block 21/09); Orca pre-salt discovery (Block 20/11)

Established new deepwater Gulf of Mexico play and acquired 44 Gulf of Mexico lease blocks at OCS Lease Sale

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Successful appraisal drilling at North Platte with Rowan Reliance drillship; Successful appraisal drilling at Shenandoah and Anchor

Announced sale of Cobalt's Angola assets to Sonangol

LEADERSHIP

Board of Directors and Committees

Joseph H. Bryant
Chairman of the Board of Directors and Chief Executive Officer, Cobalt International Energy, Inc.

Jack E. Golden[1,2]
Former Group Vice President—Exploration and Production for BP

John E. Hagale[1][*,†]
Former Executive Vice President and Chief Financial Officer of Rosetta Resources, Inc.

Kay Bailey Hutchison[3]
Former U.S. Senator

Jon A. Marshall[2][†]
Former CEO of GlobalSantaFe Corporation

Kenneth W. Moore[3]
Former Managing Director of First Reserve Corporation

Myles W. Scoggins[1,3]
President Emeritus of the Colorado School of Mines

D. Jeff van Steenbergen[2]
Co-founding and General Partner of Azimuth Capital Management

William P. Utt[3]
Former Chairman, President and CEO of KBR, Inc.

Martin H. Young, Jr.[1,2]
Former Senior Vice President and Chief Financial Officer of Falcon Seaboard Diversified, Inc.

(1) Member of Audit Committee (2) Member of Compensation Committee (3) Member of Nominating and Corporate Governance Committee
(*) Joined Board of Directors March 1, 2016 (†) Committee assignments effective March 1, 2016

Officers

Joseph H. Bryant
Chairman of the Board of Directors and Chief Executive Officer

Van P. Whitfield
Chief Operating Officer and Executive Vice President

Shannon E. Young, III
Chief Financial Officer and Executive Vice President

James W. Farnsworth
Chief Exploration Officer and Executive Vice President

James H. Painter
Executive Vice President

Shashank V. Karvé
Executive Vice President, Projects

Jeffrey A. Starzec
Executive Vice President and General Counsel

Richard A. Smith
Senior Vice President

Lynne L. Hackedorn
Vice President, Government and Public Affairs

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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2015

OR

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

For the transition period from ______ to ______

Commission File Number 001-34579

Cobalt International Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**27-0821169**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

Cobalt Center
920 Memorial City Way, Suite 100
Houston, Texas 77024
(Address of principal executive offices, including zip code)

(713) 579-9100
(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, $0.01 par value	**The New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Securities 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 ☒ No ☐

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

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 ☒ No ☐

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 ☒ No ☐

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. ☒

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. (Check one):

Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Act). Yes ☐ No ☒

As of June 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of the registrant's common stock held by non-affiliates was approximately $3.2 billion.

As of December 31, 2015, the registrant had 414,506,559 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement relating to the 2016 Annual Meeting of Shareholders, to be filed within 120 days of the end of the fiscal year covered by this report, are incorporated by reference into Part III of this Annual Report on Form 10-K.

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Cobalt International Energy, Inc.

PART I

Cautionary Note Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains estimates and forward-looking statements, principally in “Business,” “Risk Factors” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations.” Our estimates and forward-looking statements are mainly based on our current expectations and estimates of future events and trends, which affect or may affect our businesses and operations. Although we believe that these estimates and forward-looking statements are based upon reasonable assumptions, they are subject to several risks and uncertainties and are made in light of information currently available to us. Many important factors, in addition to the factors described in this Annual Report on Form 10-K, may adversely affect our results as indicated in forward-looking statements. You should read this Annual Report on Form 10-K and the documents that we have filed as exhibits hereto completely and with the understanding that our actual future results may be materially different from what we expect.

Our estimates and forward-looking statements may be influenced by the following factors, among others:

- the timing or occurrence of the closing of the sale of our interests in Block 20 and 21 offshore Angola;
- our liquidity and ability to finance our exploration, appraisal, development, and acquisition activities;
- volatility and recent severe declines in oil and gas prices;
- our ability to successfully and efficiently execute our project appraisal, development and exploration activities;
- lack or delay of partner, government and regulatory approvals related to our business or required pursuant to agreements we are party to;
- changes in environmental, safety and health laws and regulations or the implementation or interpretation of those laws and regulations;
- current and future government regulation of the oil and gas industry and our operations;
- oil and gas production rates on our properties that are currently producing oil and gas;
- projected and targeted capital expenditures and other costs and commitments;
- uncertainties inherent in making estimates of our oil and natural gas data;
- our and our partners’ ability to obtain permits to drill and develop our properties in the U.S. Gulf of Mexico;
- termination of or intervention in concessions, licenses, permits, rights or authorizations granted by the United States, Angolan and Gabonese governments to us;
- our dependence on our key management personnel and our ability to attract and retain qualified personnel;
- the ability of the containment resources we have under contract to perform as designed or contain or cap any oil spill, blow-out or uncontrolled flow of hydrocarbons;
- the availability and cost of developing appropriate oil and gas transportation and infrastructure;
- military operations, civil unrest, disease, piracy, terrorist acts, wars or embargoes;
- our vulnerability to severe weather events, especially tropical storms and hurricanes in the U.S. Gulf of Mexico;
- the cost and availability of adequate insurance coverage;
- the results or outcome of any legal proceedings or investigations we may be subject to;

- our ability to meet our obligations under our material agreements, including the agreements governing our indebtedness; and

- other risk factors discussed in the "Risk Factors" section of this Annual Report on Form 10-K.

The words "believe," "may," "will," "aim," "estimate," "continue," "anticipate," "intend," "expect," "plan" and similar words are intended to identify estimates and forward-looking statements. Estimates and forward-looking statements speak only as of the date they were made, and, except to the extent required by law, we undertake no obligation to update or to review any estimate and/or forward-looking statement because of new information, future events or other factors. Estimates and forward-looking statements involve risks and uncertainties and are not guarantees of future performance. As a result of the risks and uncertainties described above, the estimates and forward-looking statements discussed in this Annual Report on Form 10-K might not occur and our future results and our performance may differ materially from those expressed in these forward-looking statements due to, including, but not limited to, the factors mentioned above. Because of these uncertainties, you should not place undue reliance on these forward-looking statements.

Item 1. *Business*

OVERVIEW

We are an independent exploration and production company with operations currently focused in the deepwater U.S. Gulf of Mexico. In January 2016, we achieved initial production of oil and gas from the Heidelberg field. Our exploration efforts in the U.S. Gulf of Mexico have resulted in four oil and gas discoveries including the North Platte, Shenandoah, Anchor, and Heidelberg fields, each of which are in various stages of appraisal and development. We also have a non-operated interest in the Diaba Block offshore Gabon.

In August 2015, we executed a purchase and sale agreement with Sociedade Nacional de Combustíveis de Angola—Empresa Pública ("Sonangol") for the sale of our working interests in Blocks 20 and 21 offshore Angola for aggregate gross consideration of $1.75 billion before certain transaction expenses and other U.S. and Angolan taxes. The completion of this transaction is pending the receipt of Angola government approvals. We are continuing to work with Sonangol regarding the closing of the transaction, but we cannot make any assurances regarding the timing or occurrence of closing. Please see "Business—West Africa—Angola Transaction" for further information.

Our operational focus is to progress our North Platte, Shenandoah and Anchor discoveries toward project sanction; continue development drilling activities on the Heidelberg field with the aim to increase its oil and gas production over time; and selectively conduct exploration drilling on our current U.S. Gulf of Mexico acreage. We are also seeking to renew our world-wide exploration portfolio by pursuing new acreage opportunities in the U.S. Gulf of Mexico and evaluating certain other new venture opportunities. In light of the current market environment and significant downturn in oil and gas prices, we are continuing our efforts to reduce our cost structure company-wide which includes reducing or deferring certain activities.

SUMMARY OF PRIMARY ASSET BASE

Producing Properties	Operator	Initial Exploration Well Discovery Date	Subsequent Appraisal Well(s)	Project Sanction	First Production	Near-Term Activity
Heidelberg (9.375% WI)	Anadarko	2009	One has been drilled: 2012	Mid-2013	January 2016	Connect the 3rd development well that has been drilled and completed to the production facility; Drill, complete and connect two additional development wells

Properties in Appraisal and Development	Operator	Initial Exploration Well Discovery Date	Subsequent Appraisal Well(s)	Near-Term Activity
Shenandoah (20% WI)	Anadarko	2009	Three have been drilled: 2013; early 2015; late 2015	Additional appraisal drilling; Pre-sanction engineering studies
North Platte (60% WI)	Cobalt	2012	One has been drilled: 2015	Additional appraisal drilling and bypass coring operations; Pre-sanction engineering studies
Anchor (20% WI)	Chevron	2015	One has been drilled: 2015	Additional appraisal drilling; Pre-sanction engineering studies

Near-Term Exploration Prospects	Operator	Initial Exploration Well
Goodfellow	Cobalt	2016*
Anchor South	Cobalt	2017*

* *Cobalt estimate.*

U.S. GULF OF MEXICO

Production and Development

Heidelberg. The Heidelberg field is located approximately 160 miles south of the Louisiana coast in 5,300 feet of water and covers Green Canyon Blocks 859, 903 and 904. The Heidelberg project was formally sanctioned in mid-2013. Anadarko Petroleum Corporation ("Anadarko"), as operator, commenced initial oil and gas production from the Heidelberg field in January 2016. Initial production at Heidelberg was achieved with two of the first three development wells tied back to a moored production handling SPAR. The other completed development well is expected to begin production in the near future resulting in an initial total of three producing wells. Two additional development wells are expected to be drilled, completed and brought onto production at Heidelberg within the next year. Production from Heidelberg is transported to shore via dedicated oil and gas pipelines. Initial data from the first producing wells at Heidelberg and from production tests on other Heidelberg development wells indicate that production rates from Heidelberg may be materially lower than expectations. The Heidelberg field was discovered in early 2009, with the initial exploration well encountering more than 200 feet of net pay thickness in Miocene horizons. This well was located in approximately 5,200 feet of water in Green Canyon Block 859 within the Miocene trend and was drilled to a depth of approximately 30,000 feet. A subsequent appraisal well was drilled in 2012 which encountered approximately 250 feet of net pay thickness in high-quality Miocene sands. As of December 31, 2015, we had 5.6 million barrels ("MMBbls") of oil, 0.3 MMBbls of natural gas liquids ("NGLs") and 1.8 billion cubic feet ("Bcf") of gas of net proved undeveloped reserves attributed to the Heidelberg field. For more information regarding our proved undeveloped reserves, please see "—Summary of Oil and Gas Reserves." We own a 9.375% working interest in the Heidelberg field.

Appraisal and Development

North Platte. On December 5, 2012, we announced a significant oil discovery at our North Platte prospect on Garden Banks Block 959 in the deepwater U.S. Gulf of Mexico. Based on extensive wireline evaluation, the discovery well encountered over 550 net feet of oil pay in multiple high-quality Inboard Lower Tertiary reservoirs. We conducted bypass coring on the North Platte #1 exploration well, which provided additional information as we continue our evaluation of the North Platte oil discovery and plans for further appraisal and development. The North Platte #1 exploration well is located in approximately 4,400 feet of water and was drilled to a total depth of approximately 34,500 feet.

We completed drilling the initial North Platte appraisal well in the fourth quarter of 2015. This well was successful and encountered over 550 feet of net oil pay, which is similar to the discovery well, but with evidence of better developed reservoirs. We have recently completed additional sidetrack appraisal drilling operations at North Platte, which were successful and encountered approximately 500 feet of net oil pay in what appears to be excellent reservoir quality rock. We are currently conducting logging and evaluation operations on this sidetrack well. While evaluation of the well results is ongoing, pressures and fluid samples taken in the sidetrack well indicate that the rock and reservoir properties are among the best that we have encountered in the Inboard Lower Tertiary trend. We intend to conduct further appraisal drilling at North Platte in the second half of 2016. We are conducting reservoir fluids analyses and subsea studies to support our appraisal and development efforts at North Platte. Reservoir characterization and certain geologic modeling studies are ongoing in order to better understand reservoir continuity, productivity and recovery characteristics of the field. The primary terms of certain leases covering our North Platte project are scheduled to expire in October 2016. We expect to hold these leases and perpetuate the acreage associated with them by conducting continuous operations, meaning that we cannot discontinue operations at North Platte for more than 180 days or such leases will terminate. The North Platte field is in the early stages of the project development life-cycle and will require substantial additional evaluation and analysis, including additional appraisal drilling, prior to preparing a development plan and seeking formal project sanction. We are the operator of North Platte and own a 60% working interest.

Shenandoah. The Shenandoah field is located approximately 200 miles south of the Louisiana coast in 5,800 feet of water in the Walker Ridge area. In early 2009, Anadarko, as operator, drilled the Shenandoah #1 exploration well into Inboard Lower Tertiary horizons and encountered net oil pay approaching 300 feet. This well, located in approximately 5,750 feet of water in Walker Ridge Block 52, was drilled to approximately 30,000 feet. The Shenandoah #2 appraisal well was spud in the third quarter of 2012 in approximately 5,800 feet of water, about 1.3 miles southwest of the Shenandoah #1 exploration well and encountered more than 1,000 net feet of oil pay in multiple high quality Inboard Lower Tertiary reservoirs. The Shenandoah #3 appraisal well was spud in the second quarter of 2014 and evaluated the same well-developed reservoir sands 1,500 feet down-dip and 2.3 miles east of the first appraisal well. This well found an expanded geologic reservoir section, confirmed excellent reservoir qualities and delineated the potential oil-water contacts of the field. The Shenandoah #4 appraisal well was drilled in the fourth quarter of 2015 and tested the updip extent of the basin. The subsequent Shenandoah #4 sidetrack encountered over 600 feet of net oil pay, extending the lowest known oil column downdip. Anadarko, as operator, is currently evaluating development concepts for Shenandoah. The primary terms on certain leases covering our Shenandoah project expired in 2014 but are being held by continuous operations on the Shenandoah project, meaning that we cannot discontinue operations at Shenandoah for more than 180 days or such leases will terminate. We expect additional appraisal drilling on Shenandoah during 2016 and that Anadarko will eventually file for approval of a Suspension of Production in order to perpetuate this acreage. The Shenandoah field is in the early stages of the project development life-cycle and will require substantial additional evaluation, appraisal drilling, and analysis prior to the preparation of a development plan and seeking formal project sanction. We own a 20% non-operated working interest in the Shenandoah field.

Anchor. The Anchor field is located approximately 140 miles from the Louisiana coast in 5,183 feet of water. The initial Anchor exploration well was drilled in late 2014 to a total depth of 33,749 feet and encountered 690 feet of net oil pay in multiple Inboard Lower Tertiary horizons. In the second half of 2015, an appraisal sidetrack well was drilled down dip to delineate the Anchor discovery well. The appraisal well encountered 694 feet of net oil pay in a hydrocarbon column of at least 1,800 feet in Inboard Lower Tertiary reservoirs. Chevron Corporation ("Chevron"), as operator, spud the Anchor #3 appraisal well in February 2016. The primary terms on certain leases covering our Anchor project expired in 2014 but are being held by continuous operations on the Anchor project, meaning that we cannot discontinue operations at Anchor for more than 180 days or such leases will terminate. We expect that Chevron will eventually file for approval of a Suspension of Production in order to perpetuate this acreage. The Anchor field is in the early stages of the project development life-cycle and will require substantial additional evaluation and analysis, including additional appraisal drilling, prior to preparing a development plan and seeking formal project sanction. We own a 20% non-operated working interest in the Anchor discovery unit.

Exploration

Goodfellow. We plan to drill our Goodfellow #1 exploration well following the final completion of bypass coring and sidetrack operations on the North Platte appraisal well. The Goodfellow #1 exploration well will target Inboard Lower Tertiary horizons. The

Goodfellow prospect is a 3-way closure against a salt weld trap located in Keathley Canyon Blocks 129, 173 and Walker Ridge Blocks 89, 90, 133. The Goodfellow prospect is located approximately 18 miles southwest of our Shenandoah discovery in the Walker Ridge area. We expect results from the Goodfellow #1 exploration well in the second half of 2016. We are the operator and currently own a 47% working interest in the Goodfellow prospect. Prior to spudding the Goodfellow #1 exploration well, our working interest may change depending upon the participation elections of the other working interest holders in the Goodfellow prospect.

Anchor South. We believe potential exists for the Anchor reservoir to extend south onto Green Canyon Blocks 850 and 851 which we operate and have working interests of 100% and 70%, respectively. We are evaluating a potential exploration well that will target Inboard Lower Tertiary horizons on such blocks, which if successful may cause those blocks to be included within the Anchor discovery unit thereby increasing our working interest in the Anchor discovery unit.

In addition to the Goodfellow and Anchor exploration wells listed above, we are also continuing to mature our current exploration prospect inventory across the broader deepwater U.S. Gulf of Mexico, which includes potential future exploration drilling at our South Platte and Rocky Mountain prospects. See "Risk Factors—Risks Relating to Our Business—Our drilling and development plans are scheduled out over several years, making them susceptible to uncertainties that could materially alter their occurrence or timing."

General Information

Our U.S. Gulf of Mexico operations target oil-focused prospects in the subsalt Miocene and Inboard Lower Tertiary horizons in the deepwater U.S. Gulf of Mexico.

Geologic Overview

The subsalt Miocene and Inboard Lower Tertiary horizons in the deepwater U.S. Gulf of Mexico are characterized by well-defined hydrocarbon systems, comprised primarily of high-quality source rock and crude oil, and contain several of the most significant hydrocarbon discoveries in the deepwater U.S. Gulf of Mexico in recent years.

Miocene. The subsalt Miocene trend is an established play in the deepwater U.S. Gulf of Mexico. Discoveries in this trend include Thunder Horse, Atlantis, Tahiti, Mad Dog, and Stampede. This trend is characterized by high quality reservoirs and fluid properties, resulting in high production well rates.

Inboard Lower Tertiary. The Lower Tertiary horizon is an older formation than the Miocene, and, as such, is generally deeper, with greater geologic complexity. The industry has been successful in terms of locating and drilling large hydrocarbon-bearing structures in this interval. The reservoir quality of the Lower Tertiary has proven to be highly variable. Some regions, including those areas in which many of the historical Lower Tertiary discoveries have been made, exhibit lower permeability and generally lower natural gas content compared to the Miocene horizon.

However, a sub-region in the Lower Tertiary that has exhibited reservoir characteristics more similar to that of existing Miocene discoveries is the Inboard Lower Tertiary trend, which includes our oil discoveries at North Platte, Shenandoah and Anchor. The Inboard Lower Tertiary is a trend located to the north of existing Outboard Lower Tertiary fields such as St. Malo, Jack and Cascade, which are all on production from the Lower Tertiary. We were an early mover in the Inboard Lower Tertiary trend, targeting specific lease blocks as early as 2006. We believe our Inboard Lower Tertiary prospects are characterized by large, well-defined structures of a similar size to Outboard Lower Tertiary discoveries, but are differentiated by what we believe to be better reservoir quality and energy based upon data from wells drilled at our North Platte, Shenandoah and Anchor discoveries. We believe we hold a significant leasehold position in the Inboard Lower Tertiary and, to date, have had an exploration success rate of 60% in the Inboard Lower Tertiary.

Exploration Prospect Maturation Process

The process of maturing an exploration prospect from initial identification to drill-ready status begins with analyzing regional data, including industry well results, to understand a given trend's specific geology and defining those areas, or "prospects," that offer the highest potential for substantial hydrocarbon deposits while minimizing geologic risks. After these prospects are identified, we further mature our prospects by acquiring and reprocessing high resolution seismic data available in the potential prospect's direct vicinity. This includes advanced imaging information, such as wide-azimuth studies, to further our understanding of a particular prospect's characteristics, including both trapping mechanics and fluid migration patterns. Reprocessing is accomplished through a series of model building steps that incorporate the geometry of the salt and below salt geology to optimize the final image. In addition, we gather publicly available information, such as well logs, which we use to evaluate industry results and activities in order to understand the relationships between industry-drilled prospects and our portfolio of undrilled prospects. As part of the maturation of a prospect to drill-ready status, we also perform substantial drilling-related engineering work, such as generating a proposed well design, including the well evaluation and completion design, and the preparation of pore pressure prediction analysis and reports, site survey reports, and shallow hazard reports. The purpose of this work is to minimize the drilling and operational risk associated with drilling a well on a particular prospect. There are also numerous regulatory filings we must prepare and submit in order to obtain the required permits, authorizations and approvals needed to drill an exploration well on a prospect.

We may decide during any of the foregoing steps of prospect maturation that drilling an exploration well on a particular prospect may not be warranted given the geologic, drilling and economic risk profile that was developed during the prospect maturation process. Once the foregoing items, as applicable, are complete and we have determined that a prospect is ready and desirable for exploration drilling, and the geologic, economic and drilling risks associated with such prospect have been optimally mitigated, such prospect would be considered “mature.”

Plans for Appraisal and Development

In general, the life-cycle of our major project developments begins with a thorough evaluation and analysis of well logs (including offset analog wells), reservoir core samples, fluid samples and, in some cases, the results of production tests from the initial exploration well that encountered what we believe may be commercial hydrocarbons. This information, along with relevant seismic data, is used to generate locations and plans for appraisal and development wells. Depending upon the project, we may choose to drill one or more appraisal wells prior to project sanction and development, each of which will undergo thorough analysis and evaluation. The information we obtain from exploration and appraisal wells is then used to create a development plan, which will include economic assumptions on the costs of drilling and completing development wells, the front-end engineering and design of offshore production and processing facilities, including subsea, umbilical, riser and flowline systems and other related transportation infrastructure. The project will become formally sanctioned when the relevant working interest partners have approved the development plan. Typically, following formal project sanction, we will commence the construction of offshore production facilities, and proceed with development drilling and the installation of subsea architecture in order to advance the project towards initial production.

A discovery made by the initial exploration well on a prospect does not ensure that we will ultimately develop or produce hydrocarbons from such prospect or that a project development will be economically viable or successful. Following a discovery by an initial exploration well, substantial additional evaluation and analysis, such as the steps described above, will need to be performed prior to official project sanction and development. In addition, substantial amounts of capital are required to progress a project through the project development life-cycle. At any time during the project development life-cycle, we may determine that the project would be uneconomic and abandon the project, despite the fact that the initial exploration well, or subsequent appraisal wells, discovered hydrocarbons. See “Risk Factors—Risks Relating to Our Business—Our discoveries and appraisal and development projects remain subject to varying degrees of additional evaluation, analysis and partner and regulatory approvals prior to official project sanction and production.”

Leasehold Acreage

As of December 31, 2015, we owned interests in 233 blocks within the deepwater U.S. Gulf of Mexico, representing approximately 1.3 million gross (0.7 million net) acres. We are the designated operator of 213 of these blocks, or approximately 91% of our U.S. Gulf of Mexico leasehold acreage. The following schedule shows the developed and undeveloped acres in which we held interests as of December 31, 2015 in the U.S. Gulf of Mexico.

	Developed Lease Acres(1)		Undeveloped Lease Acres(2)	
	Gross	**Net**	**Gross**	**Net**
U.S. Gulf of Mexico	17,280	1,620	1,275,590	690,478

(1) Our developed lease positions of 17,280 gross (1,620 net) acres are entirely related to our Heidelberg project. The Heidelberg project was sanctioned for development in mid-2013 and started oil and gas production in January 2016.

(2) Our Shenandoah, Anchor and North Platte projects are not yet sanctioned for development and therefore the acreage associated with these projects remains classified as undeveloped. We estimate that (i) the North Platte project covers U.S. Gulf of Mexico blocks, either wholly or partially, representing 34,560 gross (20,736 net) acres; (ii) the Shenandoah project covers U.S. Gulf of Mexico blocks, either wholly or partially, representing 14,400 gross (2,880 net) acres; and (iii) the Anchor project covers U.S. Gulf of Mexico blocks, either wholly or partially, representing 20,160 gross (4,032 net) acres. If development projects related to North Platte, Anchor and Shenandoah are sanctioned, we will evaluate which acreage associated with these projects could then be classified as developed acreage.

The royalties on our lease blocks range from 12.5% to 18.75% with an average of 16.86%.

Most of our U.S. Gulf of Mexico blocks have a 10-year primary term, expiring between 2016 and 2025. Assuming we are able to commence exploration and production activities or successfully exploit our properties during the primary lease term, our leases would extend beyond the primary term, generally for the life of production. Our leasehold interest in the U.S. Gulf of Mexico decreased by 113,760 gross (65,804 net) acres in 2015. This decrease was primarily due to our relinquishment of 29 leases that we deemed to be non-prospective in order to forgo payment of future delay rentals.

The table below summarizes our undeveloped acreage scheduled to expire in the next five years in the U.S. Gulf of Mexico.

	Undeveloped Lease Acres Expiry									
	2016(1)(2)		2017(1)		2018(2)(3)(4)		2019		2020 and thereafter	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
U.S. Gulf of Mexico	276,480	160,524	57,600	29,108	538,310	267,875	63,360	31,032	339,840	200,103

(1) The gross and net acreage numbers reflected in these columns include portions of the estimated 14,400 gross (2,880 net) acres covering U.S. Gulf of Mexico blocks associated with our Shenandoah project, upon which exploration and appraisal wells have both discovered hydrocarbons, but a development project has not yet been sanctioned. The leasehold acreage in the Shenandoah project is part of the Shenandoah Unit, federally approved in 2014. We expect that the operator of the Shenandoah Unit will conduct additional appraisal drilling operations in 2016 and eventually file for approval of a Suspension of Production in order to perpetuate all of the acreage associated with the Shenandoah Unit.

(2) The gross and net acreage numbers reflected in these columns include portions of the estimated 34,560 gross (20,736 net) acres covering U.S. Gulf of Mexico blocks associated with our North Platte project, upon which exploration and appraisal wells have both discovered hydrocarbons, but a development project has not yet been sanctioned. We plan to perpetuate this acreage by an eventual unitization and sanctioned development plan and by applying for approval of a Suspension of Production.

(3) The gross and net acreage numbers reflected in these columns include portions of the 20,160 gross (4,032 net) acres covering U.S. Gulf of Mexico blocks associated with our Anchor project, upon which exploration and appraisal wells have both discovered hydrocarbons, but a development project has not yet been sanctioned. The leasehold acreage in the Anchor project is part of the Anchor Unit, federally approved in 2014. We expect that the operator of the Anchor Unit will conduct additional appraisal drilling operations in 2016 and eventually file for approval of a Suspension of Production in order to perpetuate all of the acreage associated with the Anchor Unit.

(4) The gross and net acreage number reflected in this column includes 11,520 gross (9,792 net) acres in two leases that are contiguous to the south of the Anchor Discovery Unit. These leases may have the potential to be included within the Anchor Discovery Unit if any future exploration drilling is successful.

The acreage numbers in the table above do not reflect (i) 5,760 gross (1,152 net) acres covering leases associated with our Shenandoah project whose primary term expired in 2014 but are being held by continuous operations on the Shenandoah project, or (ii) 11,520 gross (2,304 net) acres covering leases associated with our Anchor project whose primary term expired in 2014 but are being held by continuous operations on the Anchor project. We expect that the operators of both Shenandoah and Anchor will continue to conduct operations on these projects during 2016 and eventually file for approval of a Suspension of Production in order to perpetuate this acreage. See “Risk Factors—Risks Relating to Our Business—Under the terms of our various license agreements, we are required to drill wells, declare any discoveries and conduct certain development activities in order to retain exploration and production rights and failure to do so may result in substantial license renewal costs or loss of our interests in these license areas.”

Drilling Rigs

On August 5, 2013, we executed a drilling contract with Rowan Reliance Limited, an affiliate of Rowan Companies plc, for the Rowan Reliance, a new-build, ultra-deepwater dynamically positioned drillship that is currently conducting operations on the initial North Platte appraisal well. The Rowan Reliance drillship is capable of operating in water depths of up to 12,000 feet and drilling to measured depths of up to 40,000 feet. The drilling contract provides for a firm three-year commitment, which began in February 2015, at a day rate of approximately $602,000 (inclusive of mobilization fees) and two one-year extension options at day rates to be mutually agreed.

Prior Drilling Results and Drilling Statistics

The following table sets forth information with respect to the gross and net oil and gas wells we drilled in the deepwater U.S. Gulf of Mexico during the periods indicated. The information presented is not necessarily indicative of future performance, and should not be interpreted to present any correlation between the number of productive wells drilled and quantities or economic value of any reserves found. Productive wells include wells that have been drilled to the targeted depth and prove, in our opinion, to be capable of producing either oil or gas in sufficient quantities that will justify completion as an oil or gas well. A dry well is an exploration, appraisal or development well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

	U.S. Gulf of Mexico					
	2015(1)		2014(2)		2013(3)	
Wells Drilled	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploration						
Productive	3	1.0	1	0.2	1	0.2
Dry	0	—	2	0.2534	2	1.02
Development						
Productive	2	0.18750	1	0.09375	—	—
Dry	1	0.09375	—	—	—	—
Total	6	1.28125	4	0.54715	3	1.22

(1) The wells noted include appraisal wells at North Platte, Shenandoah and Anchor (all productive) and three development wells at Heidelberg (two productive and one dry).

(2) The wells noted include our Anchor #1 exploration well (productive), Shenandoah #3 appraisal well (dry), Yucatan #3 appraisal well (dry) and a Heidelberg development well (productive).

(3) The wells noted include our Shenandoah #2R appraisal well (productive), and our Ardennes #1 (dry) and Aegean #1 (dry) exploration wells. We did not drill any development wells in the U.S. Gulf of Mexico during the fiscal year ended December 31, 2013.

The following table sets forth information with respect to the gross and net oil and gas wells that are currently drilling in the U.S. Gulf of Mexico (including wells that are temporarily suspended) as of the date of this Annual Report on Form 10-K, but does not include oil and gas wells that have been drilled to their targeted depth and have subsequently been either temporarily or permanently plugged and abandoned.

U.S. Gulf of Mexico	
Gross(1)	**Net(1)**
2	0.80

(1) The wells noted are (i) bypass coring and sidetrack operations on the initial North Platte appraisal well (60% working interest) and (ii) the Anchor #3 appraisal well (20% working interest).

Strategic Relationship with Total

On April 6, 2009, we announced a long-term alliance with TOTAL E&P USA, INC. (“Total”) in which, through a series of transactions, we combined our respective U.S. Gulf of Mexico exploration lease inventory (which excludes our Heidelberg project, our Shenandoah project, and all developed or producing properties held by Total in the U.S. Gulf of Mexico) through the exchange of a 40% interest in our leases for a 60% interest in Total’s leases. The initial mandatory five-well program and Total’s obligation to carry a substantial share of our drilling costs has concluded. Pursuant to the alliance, Total remains obligated to pay its share of the general and administrative costs relating to our operations in the deepwater U.S. Gulf of Mexico during the 10-year alliance term, subject to certain exceptions related to retaining executive management-level personnel. We act as operator on behalf of the alliance through the exploration and appraisal phases of development. Upon completion of appraisal operations, operatorship will be determined by Total and ourselves, with the greatest importance being placed on majority (or largest) working interest ownership and the respective experience of each party in developments which have required the design, construction and ownership of a permanently anchored host facility to collect and transport oil or natural gas from such development. During the 10-year alliance term we agreed to form a reciprocal area of mutual interest (“AMI”) with Total that covers substantially all of the deepwater U.S. Gulf of Mexico, subject to certain exclusions. Pursuant to the AMI, we may be obligated to offer Total its 40% share of any U.S. Gulf of Mexico leasehold interests we acquire and Total may be obligated to offer us our 60% share of any U.S. Gulf of Mexico leasehold interests that Total acquires.

Summary of Oil and Gas Reserves

The summary data with respect to our estimated proved reserves and future cash flows has been prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), our independent reserve engineering firm, in accordance with the definitions and regulations of the Securities and Exchange Commission ("SEC") applicable to companies involved in oil and natural gas producing activities and adjusted for imbalances. The December 31, 2015 reserve report was completed on January 21, 2016, and a copy is included as an exhibit to this report.

Proved Reserves

As of December 31, 2015, our estimated net proved undeveloped reserves totaled 5.6 MMBbls of oil, 0.3 MMBbls of NGLs and 1.8 Bcf of natural gas. All of our proved reserves are attributable to our interest in the Heidelberg field in the U.S. Gulf of Mexico.

	Estimated Net Proved Reserves as of December 31, 2015			
	Oil (MMBbls)	NGL (MMBbls)	Natural Gas (Bcf)	Total (MMBOE)
Proved Developed	0	0	0	0
Proved Undeveloped	5.6	0.3	1.8	6.2
Total	5.6	0.3	1.8	6.2

All estimated future net cash flows are attributable to projected production from the Heidelberg Field in the U.S. Gulf of Mexico. The table below provides information regarding estimated future net cash flows and the prices used.

	Estimated Future Net Cash Flows (in millions, except $ per Bbl/Mcf)
Estimated Future Net Cash Flows	$ 102.6
Standardized Measure	$ 57.6
Oil price ($/Bbl)	$ 50.78
NGL price ($/Bbl)	$ 15.23
Natural gas price ($/Mcf)	$ (0.182)

Standardized Measure of Discounted Net Future Cash Flows

The standardized measure of discounted net future cash flows ("Standardized Measure") is the present value of estimated future net cash inflows from proved oil and natural gas reserves, less future development and production costs, abandonment costs and future income tax expenses, discounted at 10% per annum to reflect timing of future net cash flows. As of December 31, 2015, the Standardized Measure was approximately $57.6 million.

SEC reporting rules require companies to prepare reserve estimates using reserve definitions and pricing based on 12-month historical un-weighted first-day-of-the-month average prices, rather than year-end prices. Our estimated net proved reserves, estimated future net cash flows and Standardized Measure were determined using index prices for oil and gas and were held constant throughout the life of the assets. For oil and NGL volumes, the average Light Louisiana Sweet spot price of $54.02 per barrel was used and was adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.587 per MMBtu was used and was adjusted for energy content, transportation fees, and a regional price differential. For the proved reserves, the average spot prices are adjusted by energy content and weighted by production over the remaining lives of the properties to determine the benchmark prices used. Such benchmark prices are $50.78 per barrel of oil, $15.23 per barrel of NGL, and -$0.182 per Mcf of gas. The negative average gas price is due to the application of all transportation costs for the produced wet gas to the gas price for the sales gas volume.

Independent Qualified Estimator

We use an Independent Qualified Estimator ("IQE") to generate and update our proved reserves. The IQE is a qualified, industry recognized, external consulting firm with extensive experience in the evaluation and estimation of reserves and resources. This approach provides us with an objective, independent assessment of the reserves which comprise our portfolio.

For the year ended December 31, 2015, we engaged NSAI as our IQE to prepare independent estimates of the extent and value of the proved reserves of certain of our oil and gas properties. These reports were prepared at our request to estimate our proved reserves and related future net cash flows.

NSAI, our independent reserve engineers, was established in 1961. Over the past 50 years, NSAI has provided services to the worldwide petroleum industry that include the issuance of reserves reports and audits, acquisition and divestiture evaluations, simulation studies, exploration resources assessments, equity determinations, and management and advisory services. NSAI professionals subscribe to a code of professional conduct and NSAI is a Registered Engineering Firm in the State of Texas. NSAI is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists and does not own an interest in our properties and is not employed on a contingent fee basis.

Internal controls over reserves estimation process

Our Reserve Evaluation Policy outlines the process and standards by which reserves are estimated, classified and reported for all our proved reserves, whether they are operated by us or operated by others. Our Chief Operating Officer Van P. Whitfield is accountable for the Reserve Evaluation Policy. Mr. Whitfield has over 41 years of experience leading oil and gas exploration and production operations activities globally. He has a Bachelor of Science Degree in Petroleum Engineering from Louisiana State University.

The Reserve Estimation Policy is administered by the Reserves Process Chair ("RPC"). The RPC is accountable for the completion of the annual and any in-year reserve estimates conducted by the IQE. James H. Painter, our Executive Vice President, acts in the role of RPC. Mr. Painter has over 35 years of experience in the oil and gas industry. Mr. Painter has a Bachelor of Science Degree in Geology from Louisiana State University.

For each reserve evaluation, a qualified technical team is established to provide data to NSAI to enable NSAI to prepare its estimate of the extent and value of the proved reserves of certain of our oil and gas properties. Our qualified technical team works with NSAI to ensure the integrity, accuracy and timeliness of data we furnish to NSAI for purposes of their reserve estimation process. Our qualified technical team has over 100 combined years of industry experience among them with positions of increasing responsibility in engineering and evaluations. Each member of our team at a minimum holds a Bachelor of Science degree in petroleum engineering, geology or other relevant degree.

Our geotechnical, engineering and commercial inputs and interpretations required to calculate the reserves for our portfolio are compiled by our staff. This information is shared with the IQE in an open and collaborative manner, and the IQE is provided full access to complete and accurate information pertaining to the assets and to all applicable personnel. Any differences between reserve estimates internally generated by us and the IQE that exceed established threshold limits are reviewed to ensure the accuracy of the quantifiable data being used in the assessment; available data has been shared and discussed; and that methodologies and assumptions used in the estimations are clearly understood.

The NSAI technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Joseph J. Spellman and Mr. Ruurdjan (Rudi) de Zoeten. 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 University of Wisconsin-Platteville in 1980 with a Bachelor of Science Degree in Civil Engineering. Mr. de Zoeten has been practicing consulting petroleum geology at NSAI since 2008. Mr. de Zoeten is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 3179) and has over 25 years of practical experience in petroleum geosciences. He graduated from the University of Wisconsin, Madison, in 1986 with a Bachelor of Science Degree in Geology and from University of Texas at Austin in 1988 with a Master of Arts Degree in Geology. 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.

Our Audit Committee reviews the processes utilized in the development of our Reserve Evaluation Policy and the Reserve Report prepared by the IQE annually.

Technology used to establish proved reserves

Under the SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have proved effective by actual comparison of production from projects in the same reservoir interval, an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, NSAI uses technical and economic data including, but not limited to, well logs, geologic maps, seismic data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating of and Auditing of Oil & Gas Reserves information promulgated by the Society of Petroleum Engineers (SPE Standards). They used standard engineering and geoscience methods, or a combination of methods, including volumetric analysis, analogy and reservoir modeling that are considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. All of these reserves are for undeveloped locations; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, the conclusions necessarily represent only informed professional judgment. See “Risk Factors—Risks Relating to Our Business—Our proved reserves are estimates. Any material inaccuracies in our reserves estimates or assumptions underlying our reserves estimates could cause the quantities and net present value of our reserves to be overstated or understated.”

WEST AFRICA

Angola Transaction

On August 22, 2015, we executed a purchase and sale agreement (the “Purchase and Sale Agreement") with Sonangol for the sale by us to Sonangol of the entire issued and outstanding share capital of our indirect wholly-owned subsidiaries CIE Angola Block 20 Ltd. and CIE Angola Block 21 Ltd., which respectively hold our 40% working interest in each of Block 20 and Block 21 offshore Angola, for aggregate gross consideration of $1.75 billion before Angolan withholding taxes of approximately $19.7 million (to be netted out of the gross consideration to be paid to us) and certain other transaction expenses and U.S. and Angolan taxes (the “Angola Transaction”). The Angola Transaction is subject to Angolan government approvals.

The Purchase and Sale Agreement provides for the payment of the net consideration by Sonangol to us of (i) $250 million within 7 days following the execution of the Purchase and Sale Agreement (the “First Payment”), (ii) approximately $1.28 billion within 15 days following the receipt of the Angolan government approvals (the “Second Payment”), and (iii) $200 million within the earlier of 30 days following the execution of a transfer of operations agreement, which will contain terms and conditions governing the transition of operations on each of Block 20 and Block 21 from us to a new operator(s), or one year from the execution of the Purchase and Sale Agreement (the “Third Payment”). The Purchase and Sale Agreement further provides that within 15 days following the receipt of the Angolan government approvals, Sonangol shall reimburse us for our share of costs attributable to Block 20 and Block 21 for the period from January 1, 2015 through the date upon which we receive the Angolan government approvals (the "Reimbursement Amount"). We estimate that our share of costs attributable to Block 20 and Block 21 for the period from January 1, 2015 through December 31, 2015 is approximately $417.1 million, which excludes (i) a letter of credit cash collateralized by approximately $82.5 million related to Block 20 that will be released following the earlier of the completion of our minimum work obligations on Block 20 or consummation of the Angola Transaction and (ii) outstanding joint interest and other receivables attributable to Block 20 and Block 21 of approximately $148.6 million. Our obligation to transfer the share capital of CIE Angola Block 20 Ltd. and CIE Angola Block 21 Ltd. to Sonangol and consummate the Angola Transaction is subject to us having received the First Payment, the Second Payment and the Reimbursement Amount. If the Angolan government approvals are not received within one year from the execution date of the Purchase and Sale Agreement, the Purchase and Sale Agreement will automatically terminate and any obligations executed by the parties thereto shall be restituted in order to put such parties in their original positions as if no agreement had been executed.

We received the First Payment during the quarterly period ended September 30, 2015. The Angola Transaction is currently pending Angola government approval, and we therefore have not received the Second Payment, Third Payment or Reimbursement Amount. Please see “Item 1A. Risk Factors—The sale of our interests in Blocks 20 and 21 offshore Angola is subject to Angolan government approval, and such sale may be delayed or may not be consummated. In addition, pursuant to the terms of the purchase and sale agreement governing such sale, we are obligated to transfer our interests in Block 20 and 21 prior to receipt of all consideration for such transfer.”

Block 21 Offshore Angola

Cameia. On February 9, 2012, we announced that the Cameia #1 exploration well was drilled in 5,518 feet (1,682 meters) of water to a total depth of 16,030 feet (4,886 meters), at which point an extensive wire-line evaluation program was conducted. The results of this wire-line evaluation program confirmed the presence of a 1,180 foot (360 meter) gross continuous hydrocarbon column with over a 75% net to gross pay estimate. No gas/oil or oil/water contact was evident on the wire-line logs. An extended Drill Stem Test ("DST") was performed on the Cameia #1 exploration well to provide additional information. The DST flowed at an un-stimulated sustained rate of 5,010 barrels per day of 44-degree API gravity oil and 14.3 million cubic feet per day of associated gas (approximately 7,400 barrels of oil equivalent per day ("BOEPD")) with minimal bottom-hole pressure drawdown. The flow rate, which was restricted by surface equipment, facility and safety precautions, confirmed the presence of a very thick, high quality reservoir. On March 2, 2012, we submitted a declaration of commercial well to Sonangol with respect to the Cameia #1 exploration well. During 2012, we drilled the Cameia #2 appraisal well, which was located approximately 2.2 miles (3.5 kilometers) south of the Cameia #1 exploration well and was successful in demonstrating lateral continuity within the reservoir originally encountered by the Cameia #1 exploration well. The results from the Cameia #2 appraisal well were also important as the well discovered a lower hydrocarbon-bearing zone at least 440 feet (134 meters) deeper than that which was observed in the Cameia #1 exploration well.

On February 28, 2014, we submitted a formal declaration of commercial discovery to Sonangol with respect to our Cameia discovery. On May 28, 2014, we submitted the initial integrated field development plan for our Cameia project on Block 21 offshore Angola for approval by Sonangol and the Angola Ministry of Petroleum. Since mid-2014, we have successfully drilled the Cameia #3, #4 and #5 development wells and completed additional drilling operations on the Cameia #1A well, each of which is planned to be used as part of a Cameia development. In connection with the integrated field development plan, we have advanced the Cameia development project through front-end engineering design and procurement work related to (i) subsea, umbilical, riser and flowline systems and other related transportation infrastructure; and (ii) a floating production, storage and offloading vessel. Pursuant to discussions with Sonangol regarding the transfer of the Cameia development to a new operator(s) upon closing of the Angola Transaction, we have agreed to cease further work and suspend discussions with Cameia development suppliers and contractors pending the closing of the Angola Transaction. We have formed an internal transition team with the aim to be able to safely and efficiently transfer the Cameia development to a new operator(s) upon closing of the Angola Transaction. We are the operator of and hold a 40% working interest in the Cameia project. Our partner in the Cameia project is Sonangol Pesquisa e Produção, S.A. ("Sonangol P&P"), with a 60% working interest.

Bicuar. On January 22, 2014, we announced that the Bicuar #1A exploration well was successfully drilled to a total depth of 18,829 feet (5,739 meters) and encountered approximately 180 feet (56 meters) of net pay from multiple pre-salt intervals. Results of an extensive logging, coring and fluid acquisition program confirmed the existence of both oil and condensate in multiple intervals. No free gas zones or water contacts were observed. The results from the Bicuar #1A exploration well are significant because they confirm the first discovery of mobile hydrocarbons tested in the pre-salt syn-rift geologic interval offshore Angola. On February 13, 2014, we submitted a declaration of commercial well to Sonangol regarding the Bicuar #1A exploration well. We are the operator of and have a 40% working interest in the Bicuar discovery. Our partner in Bicuar is Sonangol P&P, with a 60% working interest.

Mavinga. On October 29, 2013, we announced that the Mavinga #1 exploration well had reached total depth and encountered approximately 100 feet (30 meters) of net oil pay. This discovery was confirmed by the successful production of oil from mini DSTs, direct pressure and permeability measurements and log and core analysis. Efforts to establish a sustained flow rate from a full DST were not successful. We believe that operational issues associated with the DST prevented the production from the oil reservoir during the production test. On November 12, 2013, we submitted a declaration of commercial well to Sonangol regarding the Mavinga #1 exploration well. We are the operator of and have a 40% working interest in the Mavinga discovery. Our partner in Mavinga is Sonangol P&P, with a 60% working interest.

License Information. We acquired our license to explore for, develop and produce oil from Block 21 offshore Angola by executing a Risk Services Agreement ("Block 21 RSA") with Sonangol. We are the operator of and have a 40% working interest in Block 21. Sonangol P&P is our partner on Block 21 and holds a 60% working interest. Our paying interest in Block 21 is 52.5% during the initial exploration period, with Sonangol P&P being obligated to pay the remaining 47.5%. The Block 21 RSA governs our operatorship of Block 21 and forms the basis of our exploration, development and production operations on this block. The Block 21 RSA provides for an initial exploration period of five years. Pursuant to Executive Decree No. 259/15, published on May 13, 2015, this five year period was extended by two years to March 1, 2017. We do not have contractual rights to sell natural gas on Block 21, but we have the right to use the natural gas during lease and production operations. Any stand-alone gas development cannot hinder or impede the development of liquid hydrocarbons on Block 21. Block 21 is approximately 1.2 million acres (4,900 square kilometers) in size. The block is 30 to 90 miles (50 to 140 kilometers) offshore in water depths of 1,300 to 5,900 feet (400 to 1,800 meters) in the central portion of the Kwanza Basin.

Block 20 Offshore Angola

Greater Orca Lontra Development (GOLD). In the first quarter of 2014, we drilled the successful Orca #1 exploration well on Block 20 offshore Angola to a measured depth of 12,703 feet (3,872 meters) and encountered approximately 250 feet (75 meters) of net oil pay in the sag and syn-rift reservoirs. A DST was conducted on the Orca #1 exploration well, and the well was successfully tested at a facility-constrained rate of 3,700 barrels of oil per day and 16.3 million cubic feet of gas per day with minimal drawdown (approximately 1%) in the upper sag section of the discovery. On April 28, 2014, we submitted a declaration of commercial well to Sonangol regarding the Orca #1 exploration well. We completed drilling the Orca #2 appraisal well on Block 20 offshore Angola in the first quarter of 2015. The results from this well, which included a drill stem test, were successful and confirmed the presence of a large oil accumulation in the sag section of the pre-salt and the discovery of oil in the deeper synrift reservoir of the pre-salt.

On December 1, 2013, we announced that our Lontra #1 exploration well had been drilled to a total depth of 13,763 feet (4,195 meters) and encountered approximately 250 feet (75 meters) of net pay in a very high quality reservoir section. The Lontra #1 exploration well encountered both a high liquids content gas interval and an oil interval. A DST was performed on the high liquids content gas interval and successfully produced a sustained flow rate of 2,500 barrels per day of condensate and 39 million cubic feet per day of gas. On December 20, 2013, we submitted a declaration of commercial well to Sonangol regarding the Lontra #1 exploration well. The deadline to file a declaration of commercial discovery with respect to our Lontra discovery was December 20, 2015. We requested an extension of this deadline from Sonangol and such extension was denied.

Given the geographical proximity of the Lontra discovery and the Orca discovery, both on Block 20 offshore Angola, our initial development concept is to tie-back the Lontra field to the Orca field as part of a hub development. The Greater Orca Lontra Development (GOLD) project is currently in the early stages of the project development life-cycle. Following the execution of the Purchase and Sale Agreement with respect to the Angola Transaction, we formed an internal transition team with the aim to be able to safely and efficiently transfer the GOLD development to a new operator(s) upon closing of the Angola Transaction. We are the operator of the GOLD project with a 40% working interest. Our partners in the GOLD project include BP Exploration Angola (Kwanza Benguela) Limited ("BP") and Sonangol P&P, with each partner holding a 30% working interest.

Exploration Wells. We are currently drilling the Zalophus #1 exploration well on Block 20 offshore Angola. We expect to drill the Golfinho #1 exploration well following the completion of operations on the Zalophus #1 exploration well. We expect these wells will be the final wells we drill offshore Angola given the Angola Transaction and the end of the three year term for the Petroserv SSV Catarina drilling contract. The drilling of the Zalophus and Golfinho exploration wells will satisfy our minimum work obligations on Block 20. Our letter of credit cash collateralized by approximately $82.5 million will be released following the earlier to occur of (i) completion of drilling operations on these wells, or (ii) the consummation of the Angola Transaction.

License Information. We acquired our license to explore for, develop and produce oil from Block 20 offshore Angola by executing a Production Sharing Contract (the "Block 20 PSC") with Sonangol. The Block 20 PSC governs our 40% working interest in and operatorship of Block 20 offshore Angola and forms the basis of our exploration, development and production operations on Block 20 offshore Angola. Sonangol P&P and BP are the other holders of working interests under the Block 20 PSC. The Block 20 PSC provides for an initial exploration period of five years, which is scheduled to expire on January 1, 2017, and an optional exploration period of an additional three years. We do not have contractual rights to sell natural gas on Block 20 offshore Angola, but we have the right to use the natural gas during lease and production operations. Any stand-alone gas development cannot hinder or impede the development of liquid hydrocarbons on Block 20. Presidential Decree No. 212/15 was passed on December 2, 2015 which established a new Block 20/15 concession area covering our Lontra discovery. It is unclear what effect the passage of this Presidential Decree has on our rights to develop Lontra under the Block 20 PSC, although we are working with Sonangol to understand its significance given the pending Angola Transaction. Furthermore, the deadline to file a declaration of commercial discovery under our Block 20 PSC with respect to our Lontra discovery was December 20, 2015. We requested an extension of this deadline from Sonangol and such extension was denied. Block 20 is approximately 1.2 million acres (4,900 square kilometers) in size or approximately 200 U.S. Gulf of Mexico blocks and is centered approximately 75 miles west of Luanda in the deepwater Kwanza Basin. It is immediately to the north of Block 21.

Block 9 Offshore Angola

License Information. We will forfeit our license on Block 9 offshore Angola on March 1, 2016 pursuant to the terms of the Risk Services Agreement ("Block 9 RSA") with Sonangol. We are currently the operator of and have a 40% working interest in Block 9. Sonangol P&P is our partner on Block 9 and holds a 60% working interest. The Block 9 RSA governs our operatorship of Block 9 and forms the basis of our exploration, development and production operations on this block. The Block 9 RSA provided for an initial exploration period of four years, which was extended by two-years to March 1, 2016 pursuant to Executive Decree 95/14. Block 9 is approximately 1 million acres (4,000 square kilometers) in size and is located immediately offshore in the southeastern-most portion of the Kwanza Basin. Water depth ranges from zero to more than 3,200 feet (1,000 meters).

Diaba Block Offshore Gabon

Diaman. On August 19, 2013, we announced that the Diaman #1B exploration well was drilled to a total depth of 18,323 feet (5,585 meters), and encountered approximately 160 to 180 feet (50 to 55 meters) of net hydrocarbons in the objective pre-salt formations on the Diaba Block offshore Gabon. The Diaman #1B exploration well successfully confirmed the existence of a working petroleum system, a salt seal, and high-quality sandstone reservoirs. We and our partners are continuing to analyze additional 3-D seismic data we acquired over the Diaba block in 2014. The operator currently expects to resume exploration drilling on the Diaba block offshore Gabon in 2017. We have a 21.25% non-operated working interest in the Diaman discovery. Our partners in the Diaman discovery include Total Gabon, as operator (42.5% working interest), Marathon Petroleum Corporation (21.25% working interest), and the Republic of Gabon (15% working interest).

License Information. We acquired our non-operated 21.25% working interest in the Diaba Block offshore Gabon by entering into an assignment agreement with Total Gabon. Through the assignment we became a party to the Production Sharing Agreement ("PSA") between the operator Total Gabon and the Republic of Gabon. The PSA gives us the right to recover costs incurred and receive a share of the remaining profit from any commercial discoveries made on the block. We have contractual rights to any form of hydrocarbons, including natural gas, discovered on our Gabon license area. The Diaba Block is approximately 2.2 million acres (9,100 square kilometers) in size or approximately 370 U.S. Gulf of Mexico blocks. The block is 40 to 120 miles (60 to 200 kilometers) offshore in water depths of 300 to 10,500 feet (100 to 3,200 meters) in the central portion of the offshore South Gabon Coastal basin.

General Information—West Africa

Geologic Overview

Offshore Angola and Gabon are characterized by the presence of salt formations and oil-bearing sediments located in pre-salt and above salt (Albian) horizons. Given the rifting that occurred when plate tectonics separated the South American and African continents, we believe the geology offshore Angola (Kwanza Basin) and Gabon (South Gabon Coastal Basin) is an analog to the geology offshore Brazil where several pre-salt discoveries are located. The basis for this hypothesis is that 150 million years ago, current day South America and Africa were part of a larger continent that broke apart. As these land masses slowly drifted away from each other, rift basins formed. These basins were filled with organic rich material and sediments, which in time became hydrocarbon source rocks and reservoirs. A thick salt layer was subsequently deposited, forming a seal over the reservoirs. Finally the continents continued to drift apart, forming two symmetric geologic areas separated by the Atlantic Ocean. This symmetry in geology is particularly notable in the deepwater areas offshore Gabon, Angola and the Campos Basin offshore Brazil. From an exploration perspective, we believe this similarity is very meaningful, particularly in the context of pre-salt Brazilian discoveries and our pre-salt discoveries at Cameia, Lontra, Mavinga, Bicuar, Orca and Diaman.

Licenses

As of December 31, 2015, our working interests in Blocks 9, 20 and 21 offshore Angola and the Diaba Block offshore Gabon comprised an aggregate 5,652,687 gross (1,840,581 net) undeveloped acres. On March 1, 2016 we will forfeit 988,668 gross (395,467 net) acres associated with Block 9 offshore Angola. We do not currently own any working interests in developed acreage offshore Angola, although exploration wells have discovered hydrocarbons at Cameia, Mavinga and Bicuar on Block 21 offshore Angola and at Lontra and Orca on Block 20 offshore Angola. In addition, the Diaman #1B exploration well on the Diaba Block offshore Gabon was also successful in discovering hydrocarbons. See "Risk Factors—Risks Relating to Our Business—Our discoveries and appraisal and development projects remain subject to varying degrees of additional evaluation, analysis and partner and regulatory approvals prior to official project sanction and production."

The table below summarizes our undeveloped acreage scheduled to expire in the next five years offshore West Africa.

	Undeveloped Acres Expiring									
	2016		2017		2018		2019		2020 and thereafter	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Offshore West Africa										
Angola:										
Block 9(1)	988,668	395,467	—	—	—	—	—	—	—	—
Block 20(2)	—	—	1,210,569	484,228	—	—	—	—	—	—
Block 21(3)	—	—	1,210,816	484,326	—	—	—	—	—	—
Gabon:										
Diaba(4)	—	—	—	—	2,242,634	476,560	—	—	—	—

(1) Pursuant to the Block 9 RSA and Executive Decree 95/14, our Block 9 acreage will expire on March 1, 2016.

(2) Pursuant to the Block 20 PSC, our license to exploration acreage on Block 20 will expire as of January 1, 2017, subject to certain extensions. This expiration date may be extended by three years if we notify Sonangol in writing of such extension at least thirty days before January 1, 2017, provided we have otherwise fulfilled our obligations under the agreement and agree to drill additional wells pursuant to the Block 20 PSC. The undeveloped acreage numbers listed in this row include acreage associated with our Lontra and Orca discoveries upon which exploration wells (and an appraisal well with respect to Orca) have discovered hydrocarbons, but a formal declaration of commercial discovery has not yet been filed with the applicable Angolan government authorities and therefore an associated development area has not yet been approved. The deadline to file a declaration of commercial discovery with respect to Lontra was December 20, 2015. We requested an extension of this deadline from Sonangol and such extension was denied. Furthermore, Presidential Decree No. 212/15 was passed on December 2, 2015 which established a new Block 20/15 concession area covering our Lontra discovery. It is unclear what effect the passage of this Presidential Decree has on our rights under the Block 20 PSC. See "Risk Factors—Risks Relating to Our Business—Under the terms of our various license agreements, we are required to drill wells, declare any discoveries and conduct certain development activities in order to retain exploration and production rights and failure to do so may result in substantial license renewal costs or loss of our interests in these license areas."

(3) Pursuant to the Block 21 RSA and Executive Decree No. 259/15, our license to exploration acreage on Block 21 will expire as of March 1, 2017, subject to certain extensions. The undeveloped acreage numbers listed in this row include acreage associated with our Cameia, Mavinga and Bicuar projects upon which exploration wells have discovered hydrocarbons and we have filed declarations of commercial wells, but associated development areas have not yet been approved. See "Risk Factors—Risks Relating to Our Business—Under the terms of our various license agreements, we are required to drill wells, declare any discoveries and conduct certain development activities in order to retain exploration and production rights and failure to do so may result in substantial license renewal costs or loss of our interests in these license areas."

(4) Pursuant to the PSA governing the Diaba Block and certain approved extensions, our license to acreage not defined by an approved development area will expire in January 2018, subject to certain additional extensions.

Drilling Rigs

We currently have the Petroserv SSV Catarina drilling rig under contract for use in our offshore Angolan drilling campaign. We expect to release the SSV Catarina upon the later of (i) completion of operations on the Golfinho #1 exploration well or (ii) the end of the three year term under the drilling contract, which is currently set to expire in May 2016.

Prior Drilling Results and Drilling Statistics

The following table sets forth information with respect to the gross and net oil and gas wells we drilled offshore West Africa during the periods indicated. The information presented is not necessarily indicative of future performance, and should not be interpreted to present any correlation between the number of productive wells drilled and quantities or economic value of any reserves found. Productive wells include wells that have been drilled to the targeted depth and prove, in our opinion, to be capable of producing either oil or gas in sufficient quantities that will justify completion as an oil or gas well. A dry well is an exploration, appraisal or development well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

	Offshore West Africa					
	2015(1)		2014(2)		2013(3)	
Wells Drilled	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploration						
Productive	1	0.4	3	1.2	3	1.0125
Dry	—	—	2	0.8	—	—
Development						
Productive	4	1.2	—	—	—	—
Dry	—	—	—	—	—	—
Total	5	1.6	5	2.0	3	1.0125

(1) The wells noted include our Orca #2 appraisal well, Cameia #4 development well, Cameia #1A development well, Cameia #3 re-entry development well, and Cameia #5 development well. (all productive) The Cameia #5 development well is planned to be used as a pressure-maintenance well in the Cameia development.

(2) The wells noted include our Orca #1 exploration well (productive), Bicuar #1A exploration well (productive), Cameia #3 appraisal well (productive), Loengo #1 exploration well (dry), and Mupa #1 exploration well (dry).

(3) The wells noted include our Mavinga #1, Lontra #1, and Diaman #1B exploration wells (all productive).

The following table sets forth information with respect to the gross and net oil and gas wells that are currently drilling offshore West Africa (including wells that are temporarily suspended) as of the date of this Annual Report on Form 10-K, but does not include oil and gas wells that have been drilled to their targeted depth and have subsequently been either temporarily or permanently plugged and abandoned.

West Africa	
Gross(1)	**Net(1)**
1	0.40

(1) The well noted is the Zalophus #1 exploration well on Block 20 offshore Angola.

COMPETITION

The oil and gas industry is highly competitive. We encounter strong competition from other independent, major and national oil and gas companies in acquiring properties and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. As a result, our competitors may be better able to withstand the financial pressures of significant declines in oil and gas prices, unsuccessful drill attempts, delays, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb unsuccessful drill attempts, and the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position.

Competition is also strong for attractive oil and gas producing properties, undeveloped leases and drilling rights, and we cannot assure you that we will be able to compete satisfactorily when attempting to make future acquisitions.

TITLE TO PROPERTY

We believe that we have satisfactory title to our leasehold and license interests in accordance with standards generally accepted in the oil and gas industry. However, with respect to our Lontra discovery offshore Angola, Presidential Decree No. 212/15 was passed on December 2, 2015 which established a new Block 20/15 concession area covering our Lontra discovery. It is unclear what effect the passage of this Presidential Decree has on our rights to develop Lontra under the Block 20 PSC, although we are working with Sonangol to understand its significance given the pending Angola Transaction.

We currently have federal oil and gas leases covering 233 blocks within the deepwater U.S. Gulf of Mexico, representing approximately 1.3 million gross (0.7 million net) acres. In West Africa, we currently have a license on the Diaba Block offshore Gabon, and licenses for Blocks 9, 20 and 21 offshore Angola covering a total of approximately 5,652,687 gross (1,840,581 net) acres. On March 1, 2016 we will forfeit 988,668 gross (395,467 net) acres associated with Block 9 offshore Angola pursuant to the terms of the Block 9 RSA. We do not have contractual rights to sell natural gas on our Angola blocks, but we have the right to use the natural gas during lease and production operations. We do, however, have contractual rights to any natural gas from our Gabon license area and all of our U.S. Gulf of Mexico leases. Our prospect interests are subject to applicable customary royalty and other interests, liens under operating agreements and secured credit facilities, liens for current taxes, and other burdens, easements, restrictions and encumbrances customary in the oil and gas industry that we believe do not materially interfere with the use of or affect our carrying value of the prospect interests.

CONTAINMENT RESOURCES

We are a member of several industry groups that provide general and specific oil spill and well containment resources in the U.S. Gulf of Mexico, including the Helix Well Containment Group (“HWCG”), Clean Gulf Associates (“CGA”), the Marine Preservation Association (“MPA”), and National Response Corporation (“NRC”).

We are a member of HWCG Holdings, LLC, which in turn wholly owns HWCG, LLC. HWCG, LLC serves as the operating entity for the members of HWCG by carrying out day-to-day business activities and serving as a contracting party for various oil spill and well containment equipment and services on behalf of the HWCG members. Our relationship with HWCG provides us access to the Helix Producer 1, a production handling vessel, and the Helix Q4000, a multi-purpose field intervention and construction vessel. Together with various elements of relevant hardware such as hoses, connectors, risers, and similar equipment, the Helix Producer and the Helix Q4000 form the “Helix Fast Response System”. The Helix Fast Response System is currently capable of facilitating control and containment of spills in water depths up to 10,000 feet and has two capping stacks, a 15,000 psig capping stack and a 10,000 psig capping stack. The 10,000 psig capping stack is designed to have capturing and processing capabilities of 130,000 barrels of oil per day and 200 million cubic feet of gas per day. The 15,000 psig capping stack is designed to have capturing and processing capabilities of 55,000 barrels of oil per day and 100 million cubic feet of gas per day. The capping stacks are designed to handle deep, higher-pressure wells and would be used in the event a blowout preventer is ineffective. In addition to us, members of HWCG include operators such as Marathon Oil Company and Noble Energy, Inc., among others.

As a member of CGA, we have access to a large inventory of fast response oil spill recovery vessels for offshore response scenarios with remote sensing technology for locating oil slicks. In addition, the CGA fleet includes significant shoreline protection equipment and near-shore oil skimming vessels.

As a member of MPA, we have access to the resources of the Marine Spill Response Corporation (“MSRC”). MSRC provides a wide variety of surface spill equipment, including a deepwater response fleet, aerial dispersant fleet, and approximately 75% of the existing dispersant material in the U.S. Gulf of Mexico region. NRC is an umbrella response corporation that provides us access to a wide variety of surface spill response equipment as well as a wide group of surface response contractors that can address a surface response as well as play a support role in addressing a subsea well containment event. In addition, we have existing contracts with a number of contractors which have equipment that could assist in well containment efforts as well as with the surface effects of a subsea blowout or in addressing a concurrent surface spill. Examples of such equipment include, but are not limited to, anchor and supply vessels, subsea transponders and communication equipment, subsea cutting equipment, debris removal equipment, air and water monitoring and scientific support vessels, remote-operated vehicles, storage and shuttle vessels, and subsea dispersant equipment.

For our operations offshore West Africa, we have contracts in place with Wild Well Control which provide for subsea well control planning, response management, and access to two 15,000 psig capping stack systems, subsea debris removal equipment package, and subsea dispersant application equipment in air freight configuration for mobilization to Angola. We also have contracts in place for the provision of oil spill management, equipment and response services. Specifically, we have contracted with (i) Braemer-Howells, a U.K.-based company with staff in Angola, which provides us access to oil spill response management, equipment and services, (ii) the West and Central African Aerial Surveillance and Dispersant Service, a non-profit organization which provides aerial surveillance and chemical dispersant services offshore Angola utilizing aircraft based in Ghana, and (iii) Oil Spill Response Limited, a U.K.-based company which is wholly owned by exploration and production companies and provides us access to personnel and equipment for oil spill events. We have also developed an Oil Spill Response Plan to address any potential spill, and we have access to equipment which is pre-staged in Angola, including containment boom, skimming systems, chemical dispersant systems, and temporary oil storage systems.

Furthermore, we also have contracts in place with Witt-O'Brien's, The Response Group and J. Connor Consulting for the provision of additional emergency response management services to help us address an incident in either the U.S. Gulf of Mexico or West Africa.

We are also members of the Oil Spill Response, Ltd. Global Dispersant Stockpile. This membership provides us access to a supply of over 1 million gallons of dispersant for use in a subsea well control event. This stockpile is stored in six locations around the world in portable containers ready for air freight transport.

In considering the information above, specific reference should be made to the subsection of this Annual Report on Form 10-K titled "Risk Factors—Risks Relating to Our Business—We are subject to drilling and other operational hazards."

INSURANCE COVERAGE

For our U.S. Gulf of Mexico operations, we purchase (i) operator's extra expense insurance with limits per well of $650 million, which covers costs to regain control of a well, to re-drill the well and for pollution clean-up expenses associated with a loss of well control incident, (ii) third-party liability insurance with limits of $450 million including coverage for third party bodily injury or death, property damage and clean-up of pollution on a sudden and accidental basis, (iii) an insurance policy with limits of $75 million for pollution damages as defined under the Oil Pollution Act of 1990 ("OPA"), and (iv) property insurance for our interest in the Anadarko-operated Heidelberg field with limits of full replacement cost value, excluding engineering. In addition, we have identified certain of our unencumbered assets in the U.S. Gulf of Mexico to demonstrate $75 million of Oil Spill Financial Responsibility ("OSFR") through self-insurance to the Bureau of Ocean Energy Management ("BOEM") as permitted under the OPA. Towards the end of 2013, we also purchased insurance coverage for our working interest related to construction of the Anadarko operated Heidelberg field development.

For our West Africa operations, we purchase operator's extra expense insurance with limits per well of three times the amount of our nominal dry-hole authorization-for-expenditure for each well or approximately $200 to $300 million. In addition, we also purchase $50 million of third-party liability insurance. Pursuant to the Purchase and Sale Agreement governing the Angola Transaction, we are required to provide certain transition services to Sonangol, which may include continuing to support operations on Blocks 20 and 21 on a no-profit no-loss basis until Sonangol nominates a new operator(s) of such blocks. During this transition period, if any, we will have third party liability insurance available with limits of $150 million to cover those transition services.

In general, our current insurance policies cover physical damage to our oil and gas assets. The coverage is designed to repair or replace assets damaged by insurable events. Certain of our stated insurance limits scale down to our working interest in the prospect being drilled, including certain operator's extra expense and third-party liability coverage. All insurance recovery is subject to various deductibles or retentions as well as specific terms, conditions and exclusions associated with each individual policy. We believe that our coverage limits are sufficient and are consistent with what is held by our peers operating in the deepwater U.S. Gulf of Mexico and West Africa. However, there is no assurance that such coverage will adequately protect us against liability and loss from all potential consequences and damages associated with losses, should they occur. The continuation of the recent severe declines in oil and gas prices has had a negative impact on the foreign currency exchange market for the Angola Kwanza, which in turn has made it more difficult for our insurance provider in Angola to obtain foreign currency in an amount sufficient to procure adequate re-insurance. The inability of our insurance provider to obtain adequate re-insurance may jeopardize our insurance coverage or otherwise impair its ability to perform its obligations under our insurance policies and agreements.

We also purchase director and officer liability insurance. Recoveries under such insurance policies are subject to various deductibles or retentions as well as specific terms, conditions and exclusions. Certain of our insurance providers are disputing coverage for certain expenses and potential liabilities, including with respect to, our current shareholder litigation matters. We are enforcing our rights to coverage pursuant to our insurance agreements with these insurance providers and believe such expenses and potential liabilities are covered by such insurance, within certain thresholds.

In considering the information above, specific reference should be made to the subsection of this Annual Report on Form 10-K titled "Risk Factors—Risks Relating to Our Business—We may incur substantial losses and become subject to liability claims for which we may not have adequate insurance coverage" and "Risk Factors—Risks Relating to Our Business—We are subject to drilling and other operational hazards."

ENVIRONMENTAL MATTERS AND REGULATION

General

We are, and our future operations will be, subject to various stringent and complex international, foreign, federal, state and local environmental, health and safety laws and regulations governing matters including the emission and discharge of pollutants into the ground, air or water; the generation, storage, handling, use, transportation and disposal of regulated materials; and the health and safety of our employees. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- enjoin some or all of the operations of facilities deemed not in compliance with such laws and regulations or permits issued thereunder;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas exploration, drilling, production and transportation activities;
- limit or prohibit drilling activities in certain locations lying within protected or otherwise sensitive areas; and
- require remedial measures to mitigate or address pollution from our operations.

These laws, regulations and permits may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. Compliance with these laws, regulations and permits can be costly; the regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

Moreover, particularly in light of the Deepwater Horizon incident in the U.S. Gulf of Mexico, public interest in the protection of the environment and human health has increased. Offshore drilling in some areas has been opposed by environmental groups and, in other areas, has been restricted. Our operations could be adversely affected to the extent laws are enacted or other governmental action is taken that prohibits or restricts offshore drilling or imposes environmental requirements that result in increased costs to the oil and gas industry in general, such as more stringent or costly drilling safety rules, waste handling, disposal, cleanup requirements or financial responsibility and assurance requirements.

Accidental spills or releases may occur in the course of our operations, and we cannot assure you that we will not incur substantial costs and liabilities as a result, including costs relating to claims arising from damage to natural resources, property and persons. Moreover, environmental laws and regulations are complex, change frequently and have tended to become more stringent over time. Accordingly, we cannot assure you that we have been or will be at all times in compliance with such laws and regulations, or that environmental laws and regulations will not change or become more stringent in the future in a manner that could have a material adverse effect on our financial condition and results of operations.

The following is a summary of some of the existing laws or regulatory issues to which we and our business operations are or may be subject to in the future.

Impact of the 2010 U.S. Gulf of Mexico Oil Spill

On April 20, 2010, the Transocean Deepwater Horizon, a semi-submersible offshore drilling rig operating in the deepwater U.S. Gulf of Mexico under contract to BP plc exploded, burned for two days and sank, resulting in loss of life, injuries and a large oil spill. The U.S. government and its regulatory agencies with jurisdiction over oil and gas exploration, including the U.S. Department of the Interior ("DOI") and two of its agencies, the BOEM and the Bureau of Safety and Environmental Enforcement ("BSEE"), which together formerly comprised the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"), responded to this incident by imposing moratoria on drilling operations. These agencies adopted numerous new regulations and new interpretations of existing regulations regarding operations in the U.S. Gulf of Mexico that are applicable to us and with which our new applications for exploration plans and drilling permits must prove compliant. These regulations include (i) the Increased Safety Measures for Energy Development on the Outer Continental Shelf—Final Rule, which sets forth increased safety measures for offshore energy development and requires, among other things, that all offshore operators submit written certifications as to compliance with the rules and regulations for operations occurring in the Outer Continental Shelf including the submission of independent third party written certifications as to the capabilities of certain safety devices, such as blowout preventers and their components, (ii) the Workplace Safety Rule, which requires operators to develop and implement a comprehensive Safety and Environmental Management System, or SEMS, for oil and gas operations and codifies and makes mandatory the American Petroleum Institute's Recommended Practice 75, (iii) NTL No 2010-N06, which sets forth requirements for exploration plans, development and production plans and development operations coordination documents to include a blowout scenario, the assumptions and calculations that are used to determine the volume of the worst case discharge scenario, and proposed measures to prevent and mitigate a blowout and (iv) NTL No. 2010-N10, which requires that each operator submit adequate information demonstrating that it has access to and can deploy containment resources that would be adequate to promptly respond to a blowout or other loss of well control, adds additional requirements to oil spill response plans and requires that operators submit written certifications stating that the operator will conduct all authorized activities in compliance with all applicable regulations. While we conducted our own internal SEMS assessment and conducted a third party SEMS audit in 2013 to ensure we are in compliance with all applicable regulations related to our SEMS, effective June 4, 2013, the so-called SEMS II Rule amended the Work Place Safety rule to include additional safety requirements. Operators, including us, were required to comply with the SEMS II Rule, and have an independent audit completed by June 4, 2015, which we completed in advance of the deadline. In addition, the BSEE has proposed revisions to 30 CFR 250, subpart H on Oil and Gas Production Safety Systems to address recent technological advances in production safety systems and equipment used to collect and treat oil and gas from Outer Continental Shelf leases. This includes among other things, certain standards concerning the use of best available and safest technology, more rigorous design and testing requirements for boarding shut down valves, and an increase in approved leakage rates for certain safety valves. When finalized, these and any additional new regulations may result in delays in the permitting process.

BSEE also proposed in April 2015 new well control regulations, which include more stringent design requirements and operational procedures for critical well control equipment. These requirements include those aimed at improving equipment reliability, regulating drilling margin and preventing blowouts, as well as reforms in well design, well control, casing, cementing, real-time well monitoring and subsea containment. We are unable at this time to predict the final outcome of these pending regulations or their impact on us; however, if finalized as drafted, certain of our drilling operations may be delayed as required controls are implemented or may become infeasible or impossible due to the increased requirements.

Finally, BOEM has proposed updated financial assurance requirements for offshore oil and gas leases in connection with operators’ decommissioning and abandonment liabilities for facilities in the U.S. Gulf of Mexico. Depending on the final requirements, we may need to post additional financial assurances in connection with our operations or otherwise satisfy certain financial tests in order to comply.

Compliance with new and existing regulations and the interpretations of them may materially increase the cost of and time required to obtain drilling permits or conduct our drilling operations in the U.S. Gulf of Mexico or render certain drilling operations infeasible or impossible, which may adversely affect our business, financial position or future results of operations.

Oil Pollution Act of 1990

The OPA and regulations thereunder impose liability on responsible parties for damages resulting from oil spills into or upon navigable waters or in the exclusive economic zone of the U.S. Liability under the OPA is strict, joint and several and potentially unlimited. A “responsible party” under the OPA includes the lessee or permittee of the area in which an offshore facility is located. The OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility to cover potential liabilities related to an oil spill for which such person would be statutorily responsible in an amount that depends on the risk represented by the quantity or quality of oil handled by such facility. The BSEE has promulgated regulations that implement the financial responsibility requirements of the OPA. A failure to comply with the OPA’s requirements or inadequate cooperation during a spill response action may subject a responsible party to civil, administrative and/or criminal enforcement actions. Since the BP Deepwater Horizon Spill there have also been calls for increased government oversight of the offshore oil and gas industry and more stringent requirements and penalties. If adopted, certain of these proposals have the potential to adversely affect our operations by restricting areas in which we may carry out exploration or development activities and/or causing us to incur increased operating expenses or liabilities. In December 2014 the BOEM increased the liability cap for oil spill related damages from $75 million to $134 million. In addition, to satisfy OPA’s requirement that we demonstrate at least $150 million of Oil Spill Financial Responsibility, we have (i) identified certain unencumbered assets in the U.S. Gulf of Mexico to the BOEM to demonstrate $75 million of Oil Spill Financial Responsibility through self-insurance, and (ii) procured the remaining $75 million of Oil Spill Financial Responsibility through third party insurance coverage.

Clean Water Act

The U.S. Federal Water Pollution Control Act of 1972, or Clean Water Act, as amended (“CWA”), imposes restrictions and controls on the discharge of pollutants, produced waters and other oil and natural gas wastes into waters of the U.S. These controls have become more stringent over the years, and it is possible that additional restrictions will be imposed in the future. Under the CWA, permits must be obtained to discharge pollutants into regulated waters. In addition, certain state regulations and the general permits issued under the federal National Pollutant Discharge Elimination System program prohibit discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and gas industry into certain coastal and offshore waters. The CWA provides for civil, criminal and administrative penalties for unauthorized discharges of oil and other hazardous substances and imposes liability on parties responsible for those discharges for the costs of cleaning up related damage and for natural resource damages resulting from the release. Comparable state statutes impose liabilities and authorize penalties in the case of an unauthorized discharge of petroleum or its derivatives, or other hazardous substances, into state waters.

Marine Protected Areas

Executive Order 13158, issued in 2000, directs federal agencies to safeguard existing Marine Protected Areas ("MPAs") in the U.S. and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the U.S. Environmental Protection Agency ("EPA") to propose regulations under the CWA to ensure appropriate levels of protection for the marine environment. This order and related CWA regulations have the potential to adversely affect our operations by restricting areas in which we may carry out future development and exploration projects and/or causing us to incur increased operating expenses.

Consideration of Environmental Issues in Connection with Governmental Approvals

Our operations frequently require licenses, permits and other governmental approvals. Several federal statutes, including the Outer Continental Shelf Lands Act ("OCSLA"), the National Environmental Policy Act ("NEPA"), and the Coastal Zone Management Act ("CZMA") require federal agencies to evaluate environmental issues in connection with granting such approvals or taking other major agency actions. OCSLA, for instance, requires the DOI to evaluate whether certain proposed activities would cause serious harm or damage to the marine, coastal or human environment, and gives the DOI authority to refuse to issue, suspend or revoke permits and licenses allowing such activities in certain circumstances, including when there is a threat of serious harm or damage to the marine, coastal or human environment. Similarly, NEPA requires DOI and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency must prepare an environmental assessment and, potentially, an environmental impact statement. If such NEPA documents are required, the preparation of such could significantly delay the permitting process and involve increased costs. CZMA, on the other hand, aids states in developing a coastal management program to protect the coastal environment from growing demands associated with various uses, including offshore oil and natural gas development. In obtaining various approvals from the DOI, we will have to certify that we will conduct our activities in a manner consistent with any applicable CZMA program. Violation of these foregoing requirements may result in civil, administrative or criminal penalties.

Naturally Occurring Radioactive Materials

Wastes containing naturally occurring radioactive materials ("NORM") may also be generated in connection with our operations. Certain oil and natural gas exploration and production activities may enhance the radioactivity, or the concentration, of NORM. In the U.S., NORM is subject to regulation primarily under individual state radiation control regulations. In addition, NORM handling and management activities are governed by regulations promulgated by the Occupational Safety and Health Administration. These regulations impose certain requirements concerning worker protection; the treatment, storage and disposal of NORM waste; the management of waste piles, containers and tanks containing NORM; and restrictions on the uses of land with NORM contamination.

Resource Conservation and Recovery Act

The U.S. Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are currently exempt from RCRA's requirements pertaining to hazardous waste and are regulated under RCRA's non-hazardous waste and other regulatory provisions. A similar exemption is contained in many of the state counterparts to RCRA. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. Accordingly, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position. Also, in the course of our operations, we expect to generate some amounts of ordinary industrial wastes, such as waste solvents and waste oils, which may be regulated as hazardous wastes.

Air Pollution Control

The U.S. Clean Air Act, as amended ("CAA") and state air pollution laws adopted to fulfill its mandates provide a framework for national, state, regional and local efforts to protect air quality. Our operations utilize equipment that emits air pollutants subject to the CAA and other pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. Regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA or other air pollution laws and regulations, including the suspension or termination of permits and monetary fines. Recently, the EPA also proposed new air regulations for oil and gas exploration, production, transmission and storage. These include new source performance standards for volatile organic compounds (VOCs) and sulfur dioxide and air toxics standards issued in April 2012 and updated VOC performance standards for storage tanks used in crude oil and natural gas production and transmission issued in August 2013. These regulations could require us to incur additional expenses to control air emissions by installing emissions control technologies and adhering to a variety of work practice and other requirements.

Superfund

The U.S. Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA"), also known as "Superfund," imposes joint and several liability for response costs at certain contaminated properties and damages to natural resources, without regard to fault or the legality of the original act, on some classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or past owner or operator of the site where the release occurred and anyone who transported, disposed or arranged for the disposal of a hazardous substance at the site. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur and seek natural resource damages.

Protected Species and Habitats

The U.S. federal Endangered Species Act, the federal Marine Mammal Protection Act, and similar federal and state wildlife protection laws prohibit or restrict activities that could adversely impact protected plant and animal species or habitats. Oil and natural gas exploration and production activities could be prohibited or delayed in areas where protected species or habitats may be located, or expensive mitigation may be required to accommodate such activities.

Climate Change

Our operations and the combustion of petroleum and natural gas-based products results in the emission of greenhouse gases ("GHG") that could contribute to global climate change. Climate change regulation has gained momentum in recent years internationally and domestically at the federal, regional, state and local levels. Various U.S. regions and states have already adopted binding climate change legislation. In addition, the U.S. Congress has at times considered the passage of laws to limit the emission of GHGs. It is possible that federal legislation related to GHG emissions will be considered by Congress in the future.

The EPA has issued final and proposed regulations pursuant to the CAA to limit carbon dioxide and other GHG emissions. Under EPA regulations finalized in May 2010 (formerly referred to as the "Tailoring Rule"), the EPA began regulating GHG emissions from certain stationary sources in January 2011. The EPA has issued final and proposed regulations pursuant to the CAA to limit carbon dioxide and other GHG emissions. Pursuant to the EPA's "Mandatory Reporting of Greenhouse Gases" final rule ("GHG Reporting Rule"), operators of stationary sources emitting more than established annual thresholds of carbon dioxide equivalent GHGs, as well as certain oil and natural gas facilities, including certain producers and offshore exploration and production operations, must inventory and report their GHG emissions annually. In June 2013, the Obama Administration released its Climate Action Plan ("CAP") that, among other things, called upon the EPA to promulgate greenhouse gas regulations for new and existing power plants. To that end, the EPA finalized the Clean Power Plan in August 2015, which sets forth binding guidelines for GHG emissions from existing power plants, as well as rules relating to GHG emissions from new, modified and reconstructed power plants. The EPA is also required pursuant to a settlement agreement to issue GHG emissions standards for oil refineries, but no such standards have been proposed to date. In addition, CAP calls upon the EPA and other governmental agencies to identify ways in which to reduce methane emissions from various sectors, including the oil and gas industry. In August 2015 the EPA proposed new regulations to reduce methane emissions from oil and gas operations in an effort to reduce methane emissions from the oil and gas sector by up to forty-five percent by 2025. The EPA is also expected to expand its GHG Reporting Rule to cover all segments of the oil and gas industry. Additionally, the EPA and the National Highway Traffic Safety Administration administer GHG emissions standards for heavy, medium and light duty vehicles, which have become increasingly stringent over time. The most recent of such standards were issued in 2012 for light duty vehicle model years 2022 through 2025 and in 2015 the two agencies proposed a new set of such standards for heavy duty vehicle model years 2018 through 2027. Each of these pending, proposed and future laws, regulations and initiatives could adversely affect us directly as well as indirectly, as they could decrease the demand for oil and natural gas.

On the international level, on December 12, 2015, 195 nations, including the U.S., Angola and Gabon, finalized the text of an international climate change accord in Paris, France (the "Paris Agreement"), which nations may sign and officially enter into beginning in April 2016. The Paris Agreement calls for countries to set their own GHG emissions targets, make these emissions targets more stringent over time and be transparent about the GHG emissions reporting and the measures each country will use to achieve its GHG emissions targets. A long-term goal of the Paris Agreement is to limit global temperature increase to well below two degrees Celsius from temperatures in the pre-industrial era. The Paris Agreement is in effect a successor to the Kyoto Protocol, pursuant to which protocol various nations, including Angola and Gabon, have committed to reducing their GHG emissions. The Kyoto Protocol has been extended until 2020.

International and U.S. federal climate change legislation, regulation or initiatives or climate change legislation, regulation or initiatives in other regions in which we conduct business could have an adverse effect on our results of operations, financial condition and demand for oil and natural gas.

Health and Safety

Our operations are subject to the requirements of the federal U.S. Occupational Safety and Health Act ("OSH Act") and comparable foreign and state statutes. These laws and their implementing regulations strictly govern the protection of the health and safety of employees. In particular, the OSH Act hazard communication standard, EPA community right-to-know regulations under Title III of the Superfund Amendments and Reauthorization Act of 1986 and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Such laws and regulations also require us to ensure our workplaces meet minimum safety standards and provide for compensation to employees injured as a result of our failure to meet these standards as well as civil and/or criminal penalties in certain circumstances.

Other Regulation of the Oil and Gas Industry

The oil and gas industry is regulated by numerous federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry may increase our cost of doing business by increasing the future cost of transporting our production to market, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Homeland Security Regulations

The Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security ("DHS") to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and natural gas facilities that are deemed to present "high levels of security risk." The DHS is currently in the process of adopting regulations that will determine whether our operations may in the future be subject to DHS-mandated security requirements. Presently, it is not possible to accurately estimate the costs we could incur, directly or indirectly, to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Development and Production

Development and production operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, the posting of bonds in connection with various types of activities and filing reports concerning operations. U.S. laws under which we operate may also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells and decommissioning of related equipment; and
- notice to surface owners and other third parties.

Regulation of Transportation and Sale of Natural Gas

The availability, terms and cost of transportation significantly affect sales of natural gas. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. The interstate transportation and sale for resale of natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. The FERC's regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas.

Although gas prices are currently unregulated, Congress historically has been active in the area of gas regulation. We cannot predict whether new legislation to regulate natural gas 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. Sales of condensate and natural gas liquids are not currently regulated and are made at market prices.

U.S. Coast Guard and the U.S. Customs Service

The transportation of drilling rigs to the sites of our prospects in the U.S. Gulf of Mexico and our operation of such drilling rigs is subject to the rules and regulations of the U.S. Coast Guard and the U.S. Customs Service. Such regulation sets safety standards, authorizes investigations into vessel operations and accidents and governs the passage of vessels into U.S. territory. We are required by these agencies to obtain various permits, licenses and certificates with respect to our operations.

Laws and Regulations of Angola and Gabon

Our exploration and production activities offshore Angola and Gabon are subject to Angolan and Gabonese regulations, respectively. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs or affect our operations. The following are summaries of certain applicable regulatory frameworks in Angola and Gabon.

Angola

In Angola, petroleum exploration and development activities are governed by the Petroleum Activities Law (the "Angola PAL"). Pursuant to the Angola PAL, all hydrocarbons located underground are property of the State of Angola, and exploitation rights can only be granted by the President of the Republic to Sonangol, as the national concessionaire. Foreign companies may only engage in petroleum activities in Angola in association with Sonangol through a commercial company or consortium, and generally upon entering a production sharing contract or a risk services agreement.

The Angolan PAL and the regulations thereunder extensively regulate the activities of oil and gas companies operating in Angola, including financial and insurance requirements, local content and involvement requirements, exploration and development processes, and operational matters. Local content regulations stipulate which goods or services relating to the oil and gas industry must be provided by Angolan companies (being companies which are beneficially owned in their majority by Angolan citizens), whether on a sole basis or in association with foreign contractors, and which goods or services may be provided by foreign companies. Goods or services which may be provided by foreign companies are generally subject to a local preference rule, whereby Angolan companies are granted preference in tendering for such activities or services, provided that the price difference in such tender does not exceed 10% of the total tendered amount. The power to make many of the day-to-day decisions concerning petroleum activities, including the granting of certain consents and authorizations, is vested with Sonangol.

The petroleum agreements entered with Sonangol set forth the main provisions for exploration and production activities, including fiscal terms, mandatory State participation, obligations to meet domestic supply requirements, local training and spending obligations, and ownership of assets used in petroleum operations. Angolan law and these agreements also contain important limitations on assignment of interests in such licenses, including in most cases the need to obtain the consent of Angolan authorities.

Certain industry-specific and general application statutes and regulations govern health, safety and environmental matters under Angolan law. Prior to commencing petroleum operations in Angola, contractors must, among other things, prepare an environmental impact assessment and establish and implement a health and safety plan. Such environmental laws govern the disposal of by-products from petroleum operations and required oil spill preparedness capabilities. Failure to comply with these laws may result in civil and criminal liability, including, without limitation, fines or penalties.

Angola enacted the Foreign Exchange Law for the Petroleum Sector in 2012, Law N° 2/12, of January 13, 2012, which requires, among other things, that all foreign exchange operations be carried out through Angolan banks, that oil and gas companies open local bank accounts in foreign currencies in order to pay local taxes and to pay for goods and services supplied by non-resident suppliers and service providers, and also that oil and gas companies open local bank accounts in local currency in order to pay for goods and services supplied by resident suppliers and service providers. As a consequence, foreign currency proceeds obtained by oil and gas companies from the sale of their share of production cannot be retained in full outside Angola, as a portion of the proceeds required to settle tax liabilities and pay for local petroleum operations-related expenses must be deposited in and paid through Angolan banks. Furthermore, oil and gas companies are required to convert funds into local currency and deposit such funds in local bank accounts in order to pay for local petroleum operations-related expenses. The Foreign Exchange Law for the Petroleum Sector was further supplemented by Banco Nacional de Angola's Order 20/2012, of April 25, 2012, which details the procedures and mechanisms that must be adopted by oil and gas companies and sets forth a schedule for their phased implementation. Under this statute, since October 1, 2012, oil companies (including operators) are required to make all payments for goods and services supplied by foreign exchange residents (as defined in the Foreign Exchange Law) out of bank accounts domiciled in Angola, whether in national or foreign currency. As of July 1, 2013, oil and gas exploration and production companies (including operators) are now required to make all payments for goods and services provided by foreign exchange residents in local currency. From October 1, 2013 onwards, operators are required to make all payments for goods and services related to Angolan operations provided by non-residents out of bank accounts domiciled in Angola. Banco Nacional de Angola (BNA) issued Order 7/14, of October 8, 2014 which determines that oil companies shall sell to BNA the foreign currency required to pay taxes and other tax dues before the State. The operators shall also sell to BNA the foreign currency necessary to pay foreign exchange residents.

On October 8, 2013, Angola enacted Executive Decree 333/13 ("ED 333/13") which enforces a consumption tax on oil companies. ED 333/13 requires companies that provide taxable services to oil companies to assess the applicable consumption tax, and oil companies, as beneficiary of those services, must pay the net value of the service to the service provider and remit the consumption tax to the Angolan government. The services that are subject to the consumption tax include, but are not limited to, consultancy services, supply of energy, water and telecommunications, leasing of machines and other equipment, private security services and travel services. The applicable consumption tax rates are 5% or 10% of the value of the services depending on the nature of the service rendered.

On October 21, 2014, Angola published Presidential Legislative Decree no. 3-A/14 which repealed ED 333/13. This new statute provides that there will be no consumption tax applicable to the petroleum companies which are in the exploration and development phases and until first oil, subject to certain exceptions. Subject to the approval of the Ministry of Finance and Sonangol, petroleum companies may also benefit from the consumption tax exemption during the production phase should those companies demonstrate that the consumption tax causes imbalances which render the petroleum projects not economically viable.

Executive Decree no. 224/12 of 16 July approved the Operational Discharge Management Regulations. This statute applies to all operational discharges generated during petroleum operations, both onshore and offshore. It sets the zero discharge prohibition establishing that all operational discharges resulting from onshore activities into the ground, inland waters and coastal waters are prohibited, except where duly justified for safety reasons. Discharges of (i) drill cuttings contaminated with non-water based drilling muds; (ii) non-water based drilling fluids; and (iii) sands produced resulting from operations in the maritime zone are prohibited and must be brought to shore and be treated as hazardous waste. This statute requires operators such as ourselves to prepare an Operational Discharge Management Plan for all facilities or groups of facilities under its responsibility. The statute also establishes that the direct discharge of chemical products into the sea and the use of compounds where the content in aromatics is greater than 1% (one percent) as a base for the manufacture of drilling fluids are prohibited. On April 8, 2014, Executive Decree no. 97/14 was published in the Angolan official gazette. This statute approved a moratorium on the implementation of the above mentioned regulations.

See "Risk Factors—Risks Related to Our Business—Participants in the oil and gas industry are subject to complex laws that can affect the cost, manner or feasibility of doing business."

Gabon

In 2014, a new Hydrocarbons Law entered into force to regulate oil and gas activities in Gabon. It has repealed some prior laws relating to oil activities as well as all contradictory regulations contained in the remaining non-repealed laws of the oil and gas sector.

Pursuant to the Hydrocarbons Law, petroleum resources in Gabon are the property of the State of Gabon and petroleum companies undertake operations on behalf of the Government of Gabon. In order to conduct petroleum operations, oil and gas companies must enter into a hydrocarbons agreement, typically an exploration and production sharing contract ("EPSC"), with the Minister of Hydrocarbons and the Minister of Economy. Such agreement is subject to enactment by Presidential Decree, and its provisions must conform to the Hydrocarbons Law, subject to being null and void.

Furthermore, all oil companies, even those carrying out operations under the previous legal framework, must make payment of two financial contributions set forth in the new Hydrocarbons Law, namely the Investment Diversification Fund (payment of 1% of the Contractor's turnover during the production phase), and the Hydrocarbons Investment Fund (payment of 2% of the Contractor's turnover during the production phase), within two years of the entry into force thereof. Oil companies must also, within a maximum of one year from publication of the Hydrocarbons Law, set up and domicile the site rehabilitation funds for the Hydrocarbon activities ("*Fonds RES*") at the *Banque des Etats de l'Afrique Centrale* or at a Gabonese banking or financial institution.

The Hydrocarbons Law provides for a detailed legal framework in terms of organization of the sector, contents and terms and conditions of hydrocarbons agreements, liability, local content, safety and environment, domestic supply requirements, fiscal terms such as production sharing, royalty, bonuses and other charges, corporate income tax, customs, and local training obligations.

The powers to make many of the day-to-day decisions concerning petroleum activities, including the granting of certain consents and authorizations, remain vested with the Hydrocarbons General Directorate, a government authority. In addition, the national oil company—*Société Nationale des Hydrocarbures du Gabon*—currently holds, manages and takes participations in petroleum activities on behalf of the State. Pursuant to the Hydrocarbons Law, the State may acquire an equity stake of up to 20%, at market value, within any companies applying for or already holding an exclusive production authorization. The contractor must carry the State in its 20% participating interest in the hydrocarbons agreements during the exploration phase. The parties are free to agree on a higher stake at market value. Further, the national oil company may also acquire participating interests of up to 15%, at market value.

In addition to general local content regulations which require a 90/10 ratio of Gabon national to foreign expatriate workers involved in petroleum activities, pursuant to the Hydrocarbons Law, subcontracting activities are awarded in priority to Gabonese companies in which more than 80% of the workforce consists of Gabonese nationals. In this respect, only technically qualified license holders may be hired as subcontractors.

Assignment of interests is subject to the Ministry of Hydrocarbons' consent. Foreign companies carrying out production activities under the form of a local branch must incorporate a local company within two years of entry into force of the Hydrocarbons Law.

With respect to gas, the State shall enjoy exclusive marketing rights for non-associated gas while any non-commercial share of associated gas remains the property of the State.

Hydrocarbons agreements entered into prior to the Hydrocarbon Law's publication remain in force and should continue to be governed by their own provisions. Our understanding is that the Hydrocarbons Law applies to any issues not expressly dealt with in these contracts' provisions.

Our EPSC governing our license to the Diaba block offshore Gabon was entered into before the publication of the Hydrocarbon Law. The Diaba EPSC contains a stabilization clause, which provides for the stability of the legal, tax, economic and financial conditions in force at the signing of the EPSC. Pursuant to the Diaba EPSC, these conditions may not be adversely altered during the term of the agreement, however, we can make no assurance that the Hydrocarbon Law will not adversely affect our operations or assets in Gabon. See "Risk Factors—Risks Related to Our Business—Participants in the oil and gas industry are subject to complex laws that can affect the cost, manner or feasibility of doing business."

EMPLOYEES

As of December 31, 2015, we had 226 employees. None of these employees are represented by labor unions or covered by any collective bargaining agreement. We believe that relations with our employees are satisfactory. In addition, as of December 31, 2015, we had 126 contractors, consultants and secondees working in our offices and field locations. In light of the Angola Transaction, we are in the process of re-structuring our business, which will result in significant personnel reductions.

CORPORATE INFORMATION

We were incorporated pursuant to the laws of the State of Delaware as Cobalt International Energy, Inc. in August 2009 to become a holding company for Cobalt International Energy, L.P. Cobalt International Energy, L.P. was formed as a limited partnership on November 10, 2005 pursuant to the laws of the State of Delaware. Pursuant to the terms of a corporate reorganization that we completed in connection with our initial public offering, all of the interests in Cobalt International Energy, L.P. were exchanged for common stock of Cobalt International Energy, Inc. and, as a result, Cobalt International Energy, L.P. is wholly-owned by Cobalt International Energy, Inc.

AVAILABLE INFORMATION

We make certain filings with the SEC, including our Annual Report on Form 10-K, proxy statements, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments and exhibits to those reports. We make such filings available free of charge through our website, *http://www.cobaltintl.com*, as soon as reasonably practicable after they are filed with the SEC. The filings are also available through the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 between the hours of 10 a.m. and 3 p.m. on official business days or by calling 1-800-SEC-0330 for further information on the operation of the

Public Reference Room. Also, these filings are available on the internet at http://www.sec.gov. Our press releases and recent analyst presentations are also available on our website. The information on our website does not constitute a part of this Annual Report on Form 10-K and shall not be deemed to be a part hereof or incorporated into this or any our filings with the SEC.

EXECUTIVE OFFICERS

The following table sets forth certain information concerning our executive officers as of the date of this Annual Report.

Name	Age	Position
Joseph H. Bryant	60	Chairman of the Board of Directors and Chief Executive Officer
Van P. Whitfield	64	Chief Operating Officer and Executive Vice President
Shannon E. Young, III	44	Chief Financial Officer and Executive Vice President
James H. Painter	58	Executive Vice President
James W. Farnsworth	60	Chief Exploration Officer and Executive Vice President
Shashank V. Karve	60	Executive Vice President, Projects
Jeffrey A. Starzec	39	Executive Vice President and General Counsel
Richard A. Smith	56	Senior Vice President
Lynne L. Hackedorn	57	Vice President, Government and Public Affairs

Biographical Information

Joseph H. Bryant has served as Chief Executive Officer and Chairman of our Board of Directors since our inception in November 2005. Mr. Bryant has 38 years of experience in the oil and gas industry. Prior to joining Cobalt, from September 2004 to September 2005, he was President and Chief Operating Officer of Unocal Corporation, an oil and gas exploration and production company. From May 2000 to August 2004, Mr. Bryant was President of BP Exploration (Angola) Limited, from January 1997 to May 2000, Mr. Bryant was President of BP Canada Energy Company (including serving as President of certain subsidiaries of Amoco Canada Petroleum Co. between January 1997 and May 2000, prior to its merger with BP Canada), and from 1993 to 1996, Mr. Bryant served as an executive of a joint venture between Amoco Orient Petroleum Company and the China National Offshore Oil Corporation focused on developing the offshore Liuhua fields. Prior to 1993, Mr. Bryant held executive leadership positions in Amoco Production Company's business units in The Netherlands and the Gulf of Mexico, serving in many executive capacities and in numerous engineering, financial and operational roles throughout the continental United States. Mr. Bryant served on the board of directors of Berry Petroleum Company from October 2005 until May 2011. Mr. Bryant currently also serves on the board of directors of the American Petroleum Institute. Mr. Bryant holds a Bachelor of Science in Mechanical Engineering from the University of Nebraska.

Van P. Whitfield has served as Chief Operating Officer and Executive Vice President since September 2011. Mr. Whitfield served as our Executive Vice President, Operations and Development from May 2006 until September 2011. Mr. Whitfield has over 41 years of experience leading oil and gas production operations and marketing activities in North America, the United Kingdom and Europe, the Middle East and Asia. Prior to joining Cobalt, from May 2003 to May 2005, Mr. Whitfield served as Senior Vice President, Western Operations of CDX Gas LLC, an independent oil and gas company. From October 2002 to April 2003 he served as Production Unit Leader for the Angola Liquid Natural Gas Project, BP Exploration (Angola) Limited and from June 2001 to October 2002, he held the position of Vice President, Power and Water of ExxonMobil Saudi Arabia (Southern Ghawar) Ltd, an exploration and production company. Mr. Whitfield has also held the positions of Senior Vice President of BP Global Power, President and General Manager of Amoco Netherlands BV and Production Manager of Amoco (U.K.) Exploration Company, both exploration and production companies. In addition, he has held numerous operational and technical leadership positions in various Amoco Production Company locations, including: the position of Production Manager, West Texas and Engineering Manager, Worldwide. Mr. Whitfield has a Bachelor of Science Degree—Petroleum Engineering from Louisiana State University and is a graduate of the Executive Program at Stanford University.

Shannon E. Young, III has served as Executive Vice President and Chief Financial Officer since September 2015. Prior to joining Cobalt, Mr. Young served as Senior Vice President and Chief Financial Officer of Talos Energy LLC. Prior to joining Talos Energy in December 2014, Mr. Young served as a Managing Director at Goldman, Sachs & Co. from July 2010 to December 2014 and was previously an investment banker at Morgan Stanley from August 1998 to July 2010. Mr. Young earned a Bachelor in Business Administration in Finance from the University of Texas at Austin and a Masters of Business Administration with Distinction from the Tuck School of Business at Dartmouth College.

James H. Painter has served as Executive Vice President since April 2013. Mr. Painter previously served as our Executive Vice President, Gulf of Mexico from our inception in November 2005 until April 2013. Mr. Painter has more than 35 years of experience in the oil and gas industry. Prior to joining Cobalt, from February 2004 to September 2005, Mr. Painter was the Senior Vice President of Exploration and Technology at Unocal Corporation. Prior to his position at Unocal Corporation (following the merger between Ocean Energy Inc. and Devon Energy Corporation), from April 2003 to October 2003, Mr. Painter served as the Vice President of Exploration at Devon Energy Corporation, an oil and gas exploration and production company. From January 1995 to April 2003, Mr. Painter served in various manager and executive positions at Ocean Energy Inc. (and its predecessor Flores and Rucks, Inc.) with his final position as Senior Vice President of Gulf of Mexico and International Exploration. Additional industry experience includes positions at Forest Oil Corporation, an independent oil and gas exploration and production company, Mobil Oil Corporation and Superior Oil Company, Inc. Mr. Painter holds a Bachelor of Science in Geology from Louisiana State University.

James W. Farnsworth has served as our Chief Exploration Officer and Executive Vice President since April 2013. Mr. Farnsworth previously served as Chief Exploration Officer from our inception in November 2005 until April 2013. Mr. Farnsworth has had more than 35 years of experience in the oil and gas industry. From 2003 to 2005, Mr. Farnsworth held the position of Vice President of World-Wide Exploration and Technology, at BP p.l.c., a global energy company, responsible for BP p.l.c.'s global exploration business inclusive of North America, West Africa, North Africa, South America, Russia and the Far East. His prior positions at BP p.l.c., from 1983 to 2003, include: Vice President of North America Exploration; Vice President of Gulf of Mexico Exploration; Exploration Manager for Alaska; Deepwater Gulf of Mexico Production Manager for non-operated fields. Mr. Farnsworth has a Bachelor of Science Degree in Geology from Indiana University and a Masters of Science Degree in Geophysics from Western Michigan University.

Shashank V. Karve joined Cobalt in December 2014 and currently serves as our Executive Vice President, Projects. Mr. Karve has over 30 years of experience managing and executing large scale offshore oil and gas developments. Prior to joining Cobalt, from September 2011 to December 2014, Mr. Karve was President and CEO of Seanergis Management Services, a company he co-founded to offer area wide upstream and midstream infrastructure to the oil and gas industry. From 2009 until May 2011, Mr. Karve held the positions of Managing Director and Chief Operating Officer of MODEC, Inc. and Chairman and CEO of MODEC International Inc., a global provider of floating production, storage, and offloading (FPSO) vessels and other offshore oil and gas infrastructure. During this time, Mr. Karve was responsible for the on-time delivery of the first FPSOs on the pre-salt Lula field offshore Brazil and the Jubilee field offshore Ghana. From 2001 to 2008, Mr. Karve served as President and CEO of MODEC International LLC, where he oversaw MODEC's entry into the Brazilian and Angolan FPSO markets. Prior to that, Mr. Karve held several senior managerial positions with MODEC International LLC, including serving as Chief Operating Officer from 1997 to 2001. Mr. Karve received a graduate degree in Ocean Engineering from the Massachusetts Institute of Technology and a bachelor's degree in Naval Architecture and Marine Engineering from the Indian Institute of Technology.

Jeffrey A. Starzec has served as Executive Vice President and General Counsel since February 2015. Mr. Starzec also serves as our Corporate Secretary. Mr. Starzec served as our Senior Vice President and General Counsel from January 2012 to February 2015. From June 2009 until December 2011, Mr. Starzec served as our Associate General Counsel and Corporate Secretary. Prior to joining Cobalt, Mr. Starzec practiced corporate and securities law at Vinson & Elkins LLP from 2006 until 2009, where he represented a variety of energy companies, including Cobalt in connection with its strategic alliance with Total in the U.S. Gulf of Mexico. Mr. Starzec began his legal career at Baker Botts LLP and holds a Bachelor of Science in Economics from Duke University and a J.D. from Harvard Law School.

Richard A. Smith has served as Senior Vice President since September 2014. Prior to holding this position, Mr. Smith served as Senior Vice President and President of Cobalt Angola from November 2013 to September 2014. Mr. Smith served as Vice President, Investor Relations, Compliance and Risk Management from December 2012 until November 2013. Before that, Mr. Smith served as Vice President, Investor Relations and Planning from October 2011 until December 2012. Mr. Smith served as Vice President, International Business Development, Commercial and Finance from September 2010 until October 2011. From October 2007 until September 2010, Mr. Smith served as our Vice President. Mr. Smith has over 33 years of oil and gas industry experience in North American and international markets. Prior to joining Cobalt, from September 2005 to September 2007, Mr. Smith was Vice President, Joint Venture Development Corporate Affairs for the BP Russia Offshore Strategic Performance Unit, an oil and gas exploration and production unit of BP. From February 2002 to August 2005, he held the position of Vice President and then Executive Director for BP Exploration (Angola) Limited, an oil and gas exploration and production company operating in Angola. Mr. Smith's additional industry experience includes leadership positions at various companies in the oil and gas industry operating in Azerbaijan, Georgia, Turkey, the United Kingdom, the United States and Canada. Mr. Smith holds a Bachelor of Commerce from the University of Calgary.

Lynne L. Hackedorn has served as Vice President, Government and Public Affairs since October 2011. Ms. Hackedorn served as our Vice President, Government, Public Affairs and Land from September 2010 until October 2011. From April 2006 until September 2010, Ms. Hackedorn served as our Vice President, Land. Ms. Hackedorn has over 31 years of experience in the oil and gas industry. Prior to joining Cobalt, from 2001 to 2006, Ms. Hackedorn served as Senior Landman at Hydro Gulf of Mexico, L.L.C., formerly Spinnaker Exploration Company, L.L.C., an oil and gas exploration and production company, handling a variety of land functions within both the shelf and deepwater areas of the Gulf of Mexico. From 1998 to 2001, Ms. Hackedorn held management positions within the offshore Gulf of Mexico regions of Sonat Exploration GOM, Inc. and El Paso Production GOM, Inc., both oil and gas exploration and production companies. From 1994 to 1998, Ms. Hackedorn was a Landman with Zilkha Energy Company, also an oil and gas exploration and production company. Ms. Hackedorn began her career as a Landman in 1984 at ARCO Oil and Gas Company, where she worked in the onshore South Texas region from 1984 until 1990, and then in the offshore Gulf of Mexico region from 1990 until 1994. Ms. Hackedorn currently also serves on the Executive Committee and Board of Directors of National Ocean Industries Association. Ms. Hackedorn earned her Bachelor of Science in Petroleum Land Management from the University of Houston, graduating Magna Cum Laude.

Item 1A. *Risk Factors*

You should consider and read carefully all of the risks and uncertainties described below, together with all of the other information contained in this Annual Report on Form 10-K, including the consolidated financial statements and the related notes appearing at the end of this Annual Report on Form 10-K. If any of the following risks actually occurs, our business, business prospects, stock price, financial condition, results of operations or cash flows could be materially adversely affected. The risks below are not the only ones facing our company. Additional risks not currently known to us or that we currently deem immaterial may also adversely affect us. This Annual Report on Form 10-K also contains forward-looking statements, estimates and projections that involve risks and uncertainties. Our actual results could differ materially from those anticipated in the forward-looking statements as a result of specific factors, including the risks described below.

Risks Relating to Our Business

The sale of our interests in Blocks 20 and 21 offshore Angola is subject to Angolan government approval, and such sale may be delayed or may not be consummated. In addition, pursuant to the terms of the purchase and sale agreement governing such sale, we are obligated to transfer our interests in Block 20 and 21 prior to receipt of all consideration for such transfer.

On August 22, 2015, we executed a purchase and sale agreement (the "Purchase and Sale Agreement") with Sociedade Nacional de Combustíveis de Angola—Empresa Pública ("Sonangol") for the sale to Sonangol of the share capital of certain of our indirect, wholly-owned subsidiaries which hold our working interests in each of Blocks 20 and 21 offshore Angola. The consummation of this sale is subject to approval by the Angolan Ministry of Petroleum pursuant to the Angolan Petroleum Activities Law. If such approval is not received within one year from the execution date of the Purchase and Sale Agreement, this agreement will automatically terminate and any obligations executed by the parties thereto shall be restituted in order to put such parties in their original positions as if no agreement had been executed. There can be no assurance that such Angolan government approval will be forthcoming within the required time period. In addition, the closing of the sale of our interests in Blocks 20 and 21 could be delayed or ultimately not consummated for a variety of reasons, which could have a material adverse effect on our business, financial condition and results of operations.

If the closing of the sale of our interests in Blocks 20 and 21 is not consummated or is delayed indefinitely, we would need to renegotiate our license agreements governing Blocks 20 and 21 with Sonangol to provide for adjusted development schedules and other timelines. There can be no assurance that we will be able to renegotiate such agreements on favorable terms or at all. Such failure could materially adversely affect the value of such licenses. In addition, the Angolan government passed Presidential Decree No. 212/15 on December 2, 2015, which established a new Block 20/15 concession area covering our Lontra discovery. Such Presidential Decree ostensibly conflicts with our rights to develop oil from the Lontra discovery under the Block 20 PSC. Accordingly, it is unclear what effect the passage of this Presidential Decree has on our rights to develop Lontra under the Block 20 PSC, although we are working with Sonangol to understand its significance given the pending Angola Transaction. Should the closing of the sale of our interests in Blocks 20 and 21 be delayed or ultimately not consummated, we would need to resolve this potential conflict caused by the Presidential Decree. Any such resolution may not be favorable to us. As such, failure to consummate the closing of the sale of our interests in Blocks 20 and 21 could have a material adverse effect on our business, results of operations and financial condition, including our ability to service and/or repay our substantial existing indebtedness.

Pursuant to the Purchase and Sale Agreement, we are required to provide certain transition services to Sonangol, which may include continuing to support operations on Blocks 20 and 21 on a no-profit no-loss basis until Sonangol nominates a new operator or operators of such blocks, despite the fact that we may have already transferred the share capital of our subsidiaries holding our working interests in Blocks 20 and 21 to Sonangol. The duration of this transition period could be lengthy and require us to devote a substantial amount of resources to maintain operations on Blocks 20 and 21, which could have a material adverse effect on our business, financial condition or results of operations, and we may not be indemnified against any losses or liabilities that we may incur during the transition period. Furthermore, there can be no assurance that Sonangol will be able to nominate a new operator(s) for such blocks in a timely manner, which may delay the timing of required Angolan government approvals and the consummation of the sale of our interests in Blocks 20 and 21.

The consideration payable by Sonangol for our interests in Blocks 20 and 21 is to be paid in three installments. Should Angolan government approval for the sale be obtained, and should Sonangol pay the first two installments and reimburse us for our share of the costs attributable to Blocks 20 and 21 from the period from January 1, 2015 through the date upon which we receive the Angolan government approvals, we are obligated under the terms of the Purchase and Sale Agreement to transfer the share capital of our subsidiaries holding our working interests in Blocks 20 and 21 to Sonangol. The third installment, in an amount of $200 million, is due within the earlier of 30 days following the execution of a transfer of operations agreement, which will contain terms and conditions governing the transition of operations on each of Block 20 and Block 21 from us to a new operator(s), or one year from the execution of the Purchase and Sale Agreement. This third installment may not become payable until after the consummation of the transfer of our working interests. Should this occur, we would be subject to the risk that such third installment amount is not paid in full, or at all, or becomes subject to renegotiation. The Purchase and Sale Agreement is governed by the laws of the Republic of Angola and requires any disputes thereunder to be settled by arbitration. There can be no assurance that we would be successful in enforcing our rights under the Purchase and Sale Agreement. Any delays in the receipt, or failure to receive, the full amount of the consideration set forth in the Purchase and Sale Agreement could have a material adverse effect on our business, results of operations and financial condition, including our ability to service and/or repay our substantial existing indebtedness.

Continuation of the recent decline in oil and natural gas prices may adversely affect our business, financial condition and results of operations.

Oil and gas prices are in the midst of a severe and prolonged downturn. The significant decline in oil and gas prices over the past eighteen months has had, and will continue to have, a significant adverse effect on our business, results of operations, liquidity and market price of our common stock. The price that we receive for our oil and natural gas production affects our revenue, profitability, liquidity, access to capital and future growth rate. Historically, the oil and natural gas markets have been volatile and will likely continue to be volatile in the future. For example, daily settlement prices for New York Mercantile Exchange (NYMEX) West Texas Intermediate oil ranged from a high of $61.43 per barrel to a low of $34.73 per barrel during 2015. Daily settlement prices for NYMEX Henry Hub natural gas ranged from a high of $3.23 per million British thermal units (MMBtu) to a low of $1.76 per MMBtu during 2015. Recently, oil and natural gas prices have experienced an even further severe decline. Oil and natural gas prices depend on numerous factors, all of which are out of our control. These factors include, but are not limited to, the following:

- changes in supply and demand for oil and natural gas;
- the actions of the Organization of the Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- speculation as to the future price of oil and the speculative trading of oil futures contracts;
- global economic conditions, including the strength of the U.S. dollar;
- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activities, particularly in the Middle East, Africa, Russia and South America;
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories and oil and natural gas refining capacities;
- weather conditions and other natural disasters;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;

- the price and availability of competitors' supplies of oil and natural gas; and
- the price and availability of alternative fuels.

Significant declines in oil and natural gas prices for an extended period may have the following effects on our business:

- limiting our financial condition, liquidity, ability to finance our capital expenditures and results of operations;
- reducing the amount of oil and natural gas that we can produce economically;
- causing us to delay, postpone or terminate our exploration, appraisal and development activities;
- reducing any future revenues, operating income and cash flows;
- reducing the carrying value of our crude oil and natural gas properties; or
- limiting our access to sources of capital, such as equity and long-term debt.

Oil and natural gas prices have declined dramatically from mid-2014 and will likely continue to be depressed and volatile in the future. There can be no assurance that oil and natural gas prices will rebound in the near term or at all. Continuation of the substantial and extended decline in oil and natural gas prices may materially and adversely affect our future business, financial condition, and the market price of our common stock, results of operations, liquidity or ability to finance planned capital expenditures.

Our substantial level of indebtedness, which may increase over time, could reduce our financial flexibility.

We have $2.68 billion aggregate principal amount of convertible senior notes (the "notes") outstanding and have entered into a $150 million senior secured reserve-based loan. We are able to incur significant additional indebtedness pursuant to these debt instruments in the future in order to make investments or acquisitions or to explore, appraise or develop our oil and natural gas assets. In addition to our debt obligations, we have a substantial amount of contractual commitments pursuant to our license and lease agreements and rig contracts, among other things. Our level of indebtedness could affect our operations in several ways, including the following:

- a significant portion or all of our cash flows could be used to service our indebtedness;
- a high level of indebtedness could increase our vulnerability to general adverse economic and industry conditions, such as the recent severe and prolonged downturn in oil and natural gas prices;
- a high level of indebtedness may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness could prevent us from pursuing; and
- a high level of indebtedness may impair our ability to obtain additional financing in the future for our development projects, exploration drilling program, working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, risks associated with exploring for and producing oil and natural gas, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. For example, oil and gas prices have recently been in the midst of a severe and prolonged downturn, which may materially and adversely affect our future business, financial condition and results of operations. See "—Continuation of the recent extended decline in oil and natural gas prices may adversely affect our business, financial condition and results of operations." Factors that will affect our ability to raise cash through an offering of our equity securities or a refinancing of our indebtedness include financial market conditions, the value of our assets and our performance at the time we need capital. In particular, weakness in the financial markets or other financing sources, due to recent significant declines in oil and natural gas prices or otherwise, may delay or prevent us from accessing additional funding sources to refinance and/or service our existing indebtedness. Further, our liquidity and financial condition may be adversely affected if we are unable to consummate key operational transactions, including our sale of our working interests in Blocks 20 and 21 offshore Angola. See "—The sale of our interests in Blocks 20 and 21 offshore Angola is subject to Angolan government approval, and such sale may be delayed or may not be consummated. In addition, pursuant to the terms of the purchase and sale agreement governing such sale, we are obligated to transfer our interests in Block 20 and 21 prior to receipt of all consideration for such transfer." If any of these adverse conditions occur or continue, we may not be able to generate sufficient cash flows to pay the principal and interest on our indebtedness and future working capital, borrowings or equity financing may not be available to pay or refinance such indebtedness.

Failure to effectively execute our appraisal and development projects could result in significant delays and/or cost over-runs, including the delay of any future production, which could negatively impact our operating results, liquidity and financial position.

All of our appraisal and development projects are in the early stages of the project development life-cycle, except for our Heidelberg project. Our development projects and discoveries will require substantial additional evaluation and analysis, including appraisal drilling and the expenditure of substantial amounts of capital, prior to preparing a development plan and seeking formal project sanction. First production from these development projects and discoveries is not expected for several years, with the exception of our Heidelberg project which only recently began producing oil and gas. All of our development projects and discoveries are located in challenging deepwater environments and, given the magnitude and scale of the initial discoveries, will entail significant technical and financial challenges, including extensive subsea tiebacks to production facilities, pressure maintenance systems, gas re-injection systems, and other specialized infrastructure. This may include the advancement of technology and equipment necessary to withstand the higher pressures associated with producing oil and gas from Inboard Lower Tertiary horizons.

This level of development activity and complexity requires significant effort from our management and technical personnel and places additional requirements on our financial resources and internal financial controls. In addition, we have increased dependency on third-party technology and service providers and other supply chain participants for these complex projects. We may not be able to fully execute these projects due to:

- the timing or occurrence of the closing of the sale of our interests in Block 20 and 21 offshore Angola;
- persistent low oil and natural gas prices;
- inability to obtain sufficient and timely financing;
- inability to attract and/or retain sufficient quantity of personnel with the skills required to bring these complex projects to production on schedule and on budget;
- significant delays in delivery of essential items or performance of services, cost overruns, supplier insolvency, or other critical supply failure could adversely affect project development;
- inability to advance certain technologies;
- lack of partner or government approval for projects;
- civil disturbances, anti-development activities, legal challenges or other interruptions which could prevent access; and
- drilling hazards or accidents or natural disasters.

We may not be able to compensate for, or fully mitigate, these risks.

Our business plan requires substantial additional capital, which we may be unable to raise on acceptable terms in the future, which may in turn limit our ability to execute our development projects and achieve production, conduct exploration activities or renew our exploration portfolio.

For the year ended December 31, 2015, we did not generate any revenue from operations and only recently began producing oil and gas. Our capital outlays and operating expenditures will increase substantially over at least the next several years as we expand our operations and will vastly exceed the revenue we receive from our oil and gas operations. Developing major offshore oil and gas projects, especially in complex and challenging environments, continuing exploration activities and obtaining additional leases or concessional licenses and seismic data are very expensive, and we expect that we will need to raise substantial additional capital, through future private or public equity offerings, asset sales, strategic alliances or debt or project financing. The recent significant and sustained decline in oil and natural gas prices may make it more difficult for us to obtain additional financing.

Our future capital requirements will depend on many factors, including:

- our ability to consummate key sales or acquisitions, including the sale of our interests in Blocks 20 and 21 offshore Angola;
- the performance of the producing wells on our Heidelberg development;
- the scope, rate of progress and cost of our exploration, appraisal and development activities;
- lack of partner participation in exploration, appraisal or development operations;
- the extent to which we invest in additional oil leases or concessional licenses;
- oil and natural gas prices;
- our ability to locate and acquire hydrocarbon reserves;
- our ability to produce oil or natural gas from those reserves;
- our ability to meet the timelines for development set forth in our leases;
- the terms and timing of any drilling and other production-related arrangements that we may enter into; and
- the timing of partner and governmental approvals and/or concessions.

If the closing of the Angola Transaction is delayed, or if the Angola Transaction is ultimately not consummated, we may be forced to raise a substantial amount of capital. Additional financing may not be available on favorable terms, or at all, due to our substantial level of indebtedness, the recent severe and continuing downturn in oil and natural gas prices or otherwise. Even if we succeed in selling additional securities to raise funds, at such time the ownership percentage of our existing stockholders could be diluted, and new investors may demand rights, preferences or privileges senior to those of existing stockholders. If we raise additional capital through debt financing, the financing may involve covenants that restrict our business activities. If we choose to farm-out interests in our leases or licenses, we would dilute our ownership interest subject to the farm-out and any potential value resulting therefrom, and we may lose operating control over such prospects.

In response to the recent decline in oil and gas prices, certain of our partners have announced significant capital expenditure reductions, which may cause such partners to elect not to participate in the drilling of a particular exploration or appraisal well with us. This could dramatically increase our share of the costs of such operation and may cause us to cancel or delay certain operations and may materially adversely impact our liquidity and results of operations.

In order to protect our exploration and production rights in our license areas, we must meet various drilling and declaration requirements. Assuming we are able to commence exploration and production activities or successfully exploit our properties during the primary license term, our licenses over the developed areas of a prospect could extend beyond the primary term, generally for the life of production. However, unless we make and declare discoveries within certain time periods specified in the documents governing our licenses, our interests in either the undeveloped parts of our license areas (as is the case in Angola and Gabon) or the whole block (as is the case in the deepwater U.S. Gulf of Mexico) may be forfeited, we may be subject to significant penalties or be required to make additional payments in order to maintain such licenses. The costs to maintain licenses may fluctuate and may increase significantly since the original term, and we may not be able to renew or extend such licenses on commercially reasonable terms or at all. If we are not successful in raising additional capital, we may be unable to execute our development projects, continue our exploration activities or successfully exploit our properties, and we may lose the rights to develop these properties upon the expiration of our licenses.

The productivity of the Heidelberg field is uncertain, and the production rates achieved from the initial development wells drilled at Heidelberg may be materially lower than expectations.

The productivity of the Heidelberg field is uncertain and the production rates achieved from the initial development wells drilled at Heidelberg may be materially lower than expectations. Oil and gas production from the Heidelberg field commenced in January 2016 and it may take a significant amount of time to ramp up production. Production rates from deepwater oil and gas developments may deviate substantially from expectations due to a variety of factors, including unforeseen geologic complexities, inability to maintain adequate pressures within the field reservoir, and failure or non-performance of key production equipment and infrastructure, including production facilities. Deepwater oil and gas developments are extremely complex and the downside risks to production levels are especially acute in the early stages of production. If we realize lower production rates than expected from Heidelberg, this may cause a material adverse effect on our results of operations, liquidity and financial condition.

We have limited proved reserves and areas that we decide to drill may not yield hydrocarbons in commercial quantities or quality, or at all.

We have limited proved reserves and our exploration portfolio consists of identified yet unproven exploration prospects based on available seismic and geological information that indicates the potential presence of hydrocarbons. The exploration, appraisal and development wells we drill may not yield hydrocarbons in commercial quantities or quality, or at all. In addition, while our exploration efforts are oil-focused, any well we drill may discover gas or other hydrocarbons, which, in the case of Angola, we may not have rights to develop or produce. Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. We have drilled a limited number of appraisal wells on our discoveries. Undue reliance should not be placed on our limited drilling results or any estimates of the characteristics of our projects or prospects, including any derived calculations of our potential resources or reserves based on these limited results and estimates. Additional appraisal wells, other testing and production data from completed wells will be required to fully appraise our discoveries, to better estimate their characteristics and potential resources and reserves and to ultimately understand their commerciality and economic viability. Accordingly, we do not know how many of our development projects, discoveries or exploration prospects will contain hydrocarbons in sufficient quantities or quality to recover drilling and completion costs or to be economically viable. Even if hydrocarbons are found on our exploration prospects in commercial quantities, construction costs of oil pipelines, production platforms, facilities or subsea infrastructure, as applicable, and transportation costs may prevent such prospects from being economically viable. We will require various regulatory approvals in order to develop and produce from any of our discoveries, which may not be forthcoming or may be delayed.

Additionally, the analogies drawn by us from available data from other wells, more fully explored prospects or producing fields may not prove valid in respect of our drilling prospects. We may terminate our drilling program for a prospect if data, information, studies and previous reports indicate that the possible development of our prospect is not commercially viable and, therefore, does not merit further investment. If a significant number of our prospects do not prove to be successful, our business, financial condition and results of operations will be materially adversely affected.

To date, there has been limited exploration, appraisal and development drilling which has targeted the Inboard Lower Tertiary trend in the deepwater U.S. Gulf of Mexico, an area in which we intend to focus a substantial amount of our exploration, appraisal and development efforts.

Our discoveries and appraisal and development projects remain subject to varying degrees of additional evaluation, analysis and partner and regulatory approvals prior to official project sanction and production.

Our use of the term "development project" in this Annual Report on Form 10-K refers to our existing discoveries upon which we have conducted appraisal or development drilling. Our use of the term "discoveries" in this Annual Report on Form 10-K refers to our existing discoveries and is not intended to refer to (i) our exploration portfolio as a whole, (ii) prospects where drilling activities have not discovered hydrocarbons or (iii) our undrilled exploration prospects. A discovery made by the initial exploration well on a prospect does not ensure that we will ultimately develop or produce hydrocarbons from such prospect or that a development project will be economically viable or successful. Following a discovery by an initial exploration well, substantial additional evaluation, analysis, expenditure of capital and partner and regulatory approvals will need to be performed and obtained prior to official project sanction and development, which may include (i) the drilling of appraisal wells, (ii) the evaluation and analysis of well logs, reservoir core samples, fluid samples and the results of production tests from both exploration and appraisal wells, and (iii) the preparation of a development plan which includes economic assumptions on future oil and gas prices, the costs of drilling development wells, and the construction or leasing of offshore production facilities and transportation infrastructure. Regulatory approvals are also required to proceed with certain development plans.

Any of the foregoing steps of evaluation and analysis may render a particular development project uneconomic, and we may ultimately decide to abandon the project, despite the fact that the initial exploration well, or subsequent appraisal or development wells, discovered hydrocarbons. We may also decide to abandon a project based on forecasted oil and gas prices or the inability to obtain sufficient financing. We may not be successful in obtaining partner or regulatory approvals to develop a particular discovery, which could prevent us from proceeding with development and ultimately producing hydrocarbons from such discovery, even if we believe a development would be economically successful.

Our proved reserves are estimates. Any material inaccuracies in our reserves estimates or assumptions underlying our reserves estimates could cause the quantities and net present value of our reserves to be overstated or understated.

There are numerous uncertainties inherent in estimating oil and natural gas reserves and their value. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. Because of the high degree of judgment involved, the accuracy of any reserve estimate is inherently imprecise, and a function of the quality of available data and the engineering and geological interpretation. Our reserves estimates are based on 12-month average prices; therefore, reserves quantities will change when actual prices increase or decrease. In addition, results of drilling, testing, and production may substantially change the reserve estimates for a given reservoir over time. The estimates of our proved reserves and estimated future net revenues also depend on a number of factors and assumptions that may vary considerably from actual results, including:

- historical production from an area compared with production from similar producing areas;
- assumed effects of regulation by governmental agencies and court rulings;
- assumptions concerning future oil and natural-gas prices, future operating costs and capital expenditures; and
- estimates of future severance and excise taxes, workover costs, and remedial costs.

For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of those reserves and estimates of the future net cash flows expected from them prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, reserves estimates may be subject to upward or downward adjustment, and actual production, revenue and expenditures with respect to our reserves likely will vary, possibly materially, from estimates. Additionally, because our reserves estimates are calculated using volumetric analysis, those estimates are less reliable than the estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure. In addition, realization or recognition of proved undeveloped reserves will depend on our development schedule and plans. A change in future development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved.

We are not, and may not be in the future, the operator of all our properties, and do not, and may not in the future, hold all of the working interests in our properties. Therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated and to an extent, any non-wholly owned, assets.

We are not the operator of our Heidelberg, Shenandoah and Anchor projects. The Heidelberg development project commenced production in January 2016 and is currently our only source of revenue. We are also not the operator on the Diaba Block offshore Gabon. As a non-operator of Heidelberg, Shenandoah and Anchor, we are subject to additional risks to our business and financial condition as the ultimate technical, operational and economic success of these projects will depend upon the efforts of our competitors. The long-term success of our business will depend in part upon whether Heidelberg, Shenandoah and Anchor are successful from a technical, operational and economic perspective, which we will have limited ability to control or influence as a non-operator.

As we carry out our exploration and development programs, we may enter into arrangements with respect to existing or future prospects that result in a greater proportion of our prospects being operated by others. In addition, the terms of our current or future licenses or leases may require at least the majority of working interests to approve certain actions. As a result, we may have limited ability to exercise influence over the operations of the prospects operated by our partners or which are not wholly-owned by us, as the case may be. Dependence on the operator or our partners could prevent us from realizing our target returns for those prospects. Further, it may be difficult for us to minimize the cycle time between discovery and initial production with respect to prospects for which we do not operate or wholly-own. The success and timing of exploration and development activities operated by our partners will depend on a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the operator’s expertise and financial resources;
- partner, government and regulatory approvals;

- selection of technology; and
- the rate of production of reserves, if any.

This limited ability to exercise control over the operations of some of our prospects may cause a material adverse effect on our results of operations and financial condition.

Development drilling may not result in commercially productive quantities of oil and gas reserves.

Our exploration success has provided us with a number of major development projects on which we are moving forward. We must successfully execute our development projects, including development drilling, in order to generate future production and cash flow. However, development drilling is not always successful and the profitability of development projects may change over time.

For example, in new development projects available data may not allow us to completely know the extent of the reservoir or choose the best locations for drilling development wells. Therefore, a development well we drill may be a dry hole or result in noncommercial quantities of hydrocarbons. Projects in frontier areas may require the development of special technology for development drilling or well completion and we may not have the knowledge or expertise in applying new technology. All costs of development drilling and other development activities are capitalized, even if the activities do not result in commercially productive quantities of hydrocarbon reserves. This puts a property at higher risk for future impairment if commodity prices decrease or operating or development costs increase.

Our drilling and development plans are scheduled out over several years, making them susceptible to uncertainties that could materially alter their occurrence or timing.

Our drilling and development plans on our acreage are scheduled out over a multi-year period. Our drilling and development plans depend on a number of factors, including the availability of capital and equipment, qualified personnel, seasonal and weather conditions, regulatory and block partner approvals, civil and political conditions, oil prices, costs and drilling results. The final determination on whether to drill any exploration, appraisal, or development well, including the exact drilling location as well as the successful development of any discovery, will be dependent upon the factors described elsewhere in this Annual Report on Form 10-K as well as, to some degree, the results of our drilling activities. Because of these uncertainties, we do not know if the drilling locations we have identified or targeted will be drilled in the location we currently anticipate, within our expected timeframe or at all or if we will be able to economically produce oil or gas from these or any other potential drilling locations. As such, our actual drilling and development plans and locations may be materially different from our current expectations, which could adversely affect our results of operations and financial condition.

Drilling wells is speculative, often involving significant costs that may be more than our estimates, and may not result in any discoveries or additions to our future production or reserves. Any material inaccuracies in drilling costs, estimates or underlying assumptions will materially affect our business.

Exploring for and developing oil reserves involves a high degree of operational and financial risk, which precludes definitive statements as to the time required and costs involved in reaching certain objectives. The budgeted costs of drilling, completing and operating exploration, appraisal and development wells are often exceeded and can increase significantly when drilling costs rise due to a tightening in the supply of various types of oilfield equipment and related services. Drilling may be unsuccessful for many reasons, including geological conditions, weather, cost overruns, equipment shortages and mechanical difficulties. Exploration wells bear a much greater risk of financial loss than development wells. In the past we have experienced unsuccessful drilling efforts. Moreover, the successful drilling of an oil well does not necessarily result in a profit on investment. A variety of factors, both geological and market-related, can cause a well or an entire development project to become uneconomic or only marginally economic. Our initial drilling sites, and any potential additional sites that may be developed, require significant additional exploration and appraisal, regulatory approval and commitments of resources prior to commercial development. We face additional risks in the Inboard Lower Tertiary Trend in the U.S. Gulf of Mexico and offshore Gabon due to a general lack of infrastructure and, in the case of offshore Gabon, underdeveloped oil and gas industries and increased transportation expenses due to geographic remoteness. Thus, this may require either a single well to be exceptionally productive, or the existence of multiple successful wells, to allow for the development of a commercially viable field. If our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our business operations as proposed and would be forced to modify our plan of operation.

We contract with third parties to conduct drilling and related services on our development projects and exploration prospects for us. Such third parties may not perform the services they provide us on schedule or within budget. The recent decline in oil and gas prices may have an adverse impact on certain third parties from which we contract drilling, development and related oilfield services, which in turn could affect such companies’ ability to perform such services for us and result in delays to our exploration, appraisal and development activities. Furthermore, the drilling equipment, facilities and infrastructure owned and operated by the third parties we contract with is highly complex and subject to malfunction and breakdown. Any malfunctions or breakdowns may be outside our control and result in delays, which could be substantial. Any delays in our drilling campaign caused by equipment, facility or equipment malfunction or breakdown could materially increase our costs of drilling and cause an adverse effect on our business, financial position and results of operations.

We only recently began producing oil and gas and our future performance is uncertain.

We only recently began producing oil and gas from our Heidelberg project in which we own just a 9.375% working interest. We do not produce oil or gas from any of our other properties and do not expect to commence production from those properties for a significant amount of time. Production from our oil and gas properties will depend upon our ability to execute the appraisal and development of our projects and progress our projects through the project appraisal and development life-cycle, including the approval of development plans, obtaining formal project sanction, achieving successful appraisal and development drilling results and constructing or leasing production facilities and related subsea infrastructure. Our ability to commence production from our other properties will also depend upon us being able to obtain substantial additional capital funding on a timely basis and attract and retain adequate personnel. We have only been generating revenue from operations for a very short period of time and expect to generate only limited revenue from production for several years. Companies in their initial stages of development face substantial business and financial risks and may suffer significant losses. We have generated substantial net losses and negative cash flows from operating activities since our inception and expect to continue to incur substantial net losses as we continue our project appraisal and development activities, our exploration drilling program and our new venture activities. We face challenges and uncertainties in financial and commercial planning as a result of the complex nature of our business and uncertainties regarding the nature, scope and results of our future activities and financial commitments. In the event that our appraisal, development or exploration drilling schedules are not completed, or are delayed, modified or terminated, our operating results will be adversely affected and our operations will differ materially from the activities described in this Annual Report on Form 10-K. As a result of industry factors or factors relating specifically to us, we may have to change our methods of conducting business, which may cause a material adverse effect on our results of operations and financial condition.

The inability of one or more third parties who contract with us to meet their obligations to us may adversely affect our financial results.

We may be liable for certain costs if third parties who contract with us are unable to meet their commitments under such agreements. We are currently exposed to credit risk through joint interest receivables from our block and/or lease partners. As a result of our exploration success, we have a large inventory of development projects which will require significant capital expenditures and have long development cycle times. Our partners, both in the U.S. Gulf of Mexico and West Africa, must be able to fund their share of investment costs through the lengthy development cycle, through cash flow from operations, external credit facilities, or other sources, including project financing arrangements. Our partners may not be successful in obtaining such financing, which could negatively impact the progress and timeline for development. In addition to project development costs, our partners must also be able to fund their share of exploration and other operating expenses. The significant decline in oil and gas prices over the past eighteen months may make it more difficult for our partners to meet their obligations to us under applicable joint operating and other agreements. For example, as of December 31, 2015, outstanding joint interest and other receivables attributable to our partners in West Africa were approximately $156.6 million. We may be unable to recover such outstanding amounts, which would materially negatively impact our liquidity and financial position. Furthermore, in response to the recent decline in oil and gas prices, certain of our partners have announced significant capital expenditure reductions, which may cause such partners to elect not to participate in the drilling of a particular exploration or appraisal well with us. This could dramatically increase our share of the costs of such operation and may cause us to cancel or delay certain operations and may materially adversely impact our liquidity and results of operations.

In addition, if any of the service providers we contract with to conduct development or exploration activities file for bankruptcy or are otherwise unable to fulfill their obligations to us, we may face increased costs and delays in locating replacement vendors. The recent severe decline in oil and natural gas prices and the resulting adverse impact on our industry may have an adverse impact on or contribute to the insolvency of certain third parties from which we contract drilling, development and related oilfield services, as well as block partners, which in turn could affect such companies' ability to perform such services for us and result in delays to our exploration, appraisal and development activities. The inability or failure of third parties we contract with to meet their obligations to us or their insolvency or liquidation may adversely affect our business, results of operations or financial condition.

We are dependent on certain members of our management and technical team and our inability to retain or recruit qualified personnel may impair our ability to grow our business.

Our investors must rely upon the ability, expertise, judgment and discretion of our management and the success of our technical team in identifying, discovering and developing oil reserves and progressing our development projects toward first production. Our performance and success are dependent, in part, upon key members of our management and technical team, and their loss or departure could be detrimental to our future success. You must be willing to rely to a significant extent on our management's discretion and judgment. In addition, a significant portion of our employee base is at or near retirement age. Furthermore, we utilize the services of a number of individual consultants for contractually fixed periods of time. Our inability to retain or recruit qualified personnel may impair our ability to grow our business and develop our discoveries, which could have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

Under the terms of our various license agreements, we are required to drill wells, declare any discoveries and conduct certain development activities in order to retain exploration and production rights and failure to do so may result in substantial license renewal costs or loss of our interests in these license areas.

In order to protect our exploration and production rights in our license areas, we must meet various drilling and declaration requirements. In general, unless we make and declare discoveries within certain time periods specified in our various license agreements and leases, our interests in the undeveloped parts of our license (as is the case in Angola and Gabon) or the whole block (as is the case in the deepwater U.S. Gulf of Mexico) areas may lapse and we may be subject to significant penalties or be required to make additional payments in order to maintain such licenses. For example, pursuant to the terms of the Block 9 RSA, the initial exploration period with respect to Block 9 offshore Angola will terminate on March 1, 2016 and, on such date we will lose our license on Block 9. Pursuant to the Block 21 RSA and Executive Decree No. 259/15, the initial exploration period on Block 21 expires on March 1, 2017. Under the Block 20 PSC, in order to preserve our rights in the block, we will be required to drill four exploration wells within five years of the signing of the Block 20 PSC, or January 1, 2017, subject to certain extensions. If the Angola Transaction is not ultimately consummated and we are unable to favorably renegotiate such license terms, we may be unable to meet such deadlines and may lose our exploration rights on Blocks 20 and 21.

Furthermore, as required by our license agreements in Angola, within thirty days following a successful exploration well, we are required to submit a declaration of commercial well to Sonangol. Within two years after the date of the declaration of commercial well, we must submit to Sonangol a formal declaration of commercial discovery. Within three months from the declaration of commercial discovery, we are required to submit a development plan to Sonangol and the Angola Ministry of Petroleum for review and approval. Within forty-two months after the formal declaration of commercial discovery, we are required to commence first production from such discovery. Our failure or inability to meet these deadlines could jeopardize our production rights or result in forfeiture of our production rights with respect to these projects, which would have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

If the Angola Transaction is ultimately not consummated, certain drilling and declaration requirements will be very difficult to achieve with respect to our Cameia, Orca and Lontra discoveries and may require the need to renegotiate our various license agreements governing Blocks 20 and 21 offshore Angola with Sonangol. The deadline to file a declaration of commercial discovery with respect to our Lontra discovery was December 20, 2015. Given the pending Angola Transaction, we did not meet that deadline, although we requested an extension of this deadline from Sonangol and such extension was denied. Furthermore, Presidential Decree No. 212/15 was passed on December 2, 2015 which established a new Block 20/15 concession area covering our Lontra discovery. It is unclear what effect the passage of this Presidential Decree has on our rights under the Block 20 PSC with respect to our Lontra discovery. If the Angola Transaction is not ultimately consummated, Presidential Decree Laws may need to be passed in Angola, along with the renegotiation of our Block 20 PSC, in order to preserve our development rights with respect to Lontra. In light of (i) the apparent conflict between Presidential Decree No. 212/15 and our rights under the Block 20 PSC and (ii) the denial of our request for an extension of the declaration of commercial discovery deadline with respect to Lontra, we have elected to impair the value of our Lontra discovery included within current assets held for sale, as reflected in our consolidated financial statements as of December 31, 2015.

In addition, most of our deepwater U.S. Gulf of Mexico blocks have a 10-year primary term, expiring between 2016 and 2025. Generally, we are required to commence exploration activities or successfully exploit our properties during the primary lease term in order for these leases to extend beyond the primary lease term. A portion of the leases covering our Shenandoah and Anchor discoveries are beyond their primary term, and the operator must conduct continuous operations or obtain a Suspension of Production in order to maintain such leases. The primary terms of certain leases covering our North Platte project are scheduled to expire in October 2016. If we fail to conduct continuous operations at North Platte following such date or we fail to obtain a Suspension of Production, such leases may terminate. In addition, certain of our targeted exploration prospects, including our Goodfellow prospect, have leases that expire within the next year and even if we were to commence exploration activities prior to lease expiration, we could be required to conduct continuous operations on those prospects if the initial exploration were to be successful. This requirement to conduct continuous drilling operations may cause us to relinquish such leases despite the fact that an exploration well on such leases was successful. Accordingly, we and our partners may not be able to drill all of the prospects identified on our leases or licenses prior to the expiration of their respective terms and we can make no assurances that we, or the operator of the discoveries in which we hold a non-operated interest, will be able to successfully perpetuate leases through continuous operations or obtaining a Suspension of

Production. Should the prospects we have identified under the licenses or leases currently in place yield discoveries, we cannot assure you that we will not face delays in drilling these prospects or otherwise have to relinquish these prospects. The costs to maintain licenses over such areas may fluctuate and may increase significantly since the original term, and we may not be able to renew or extend such licenses on commercially reasonable terms or at all. Our actual drilling activities may therefore materially differ from our current expectations, which could adversely affect our business. For each of our blocks and license areas, we cannot assure you that any renewals or extensions will be granted or whether any new agreements or leases will be available on commercially reasonable terms, or, in some cases, at all.

We are subject to numerous risks inherent to the exploration and production of oil and natural gas.

Oil and natural gas exploration and production activities involve many risks that a combination of experience, knowledge and careful evaluation may not be able to overcome. Our future success will depend on the success of our exploration and production activities and on the future existence of the infrastructure and technology that will allow us to take advantage of our findings. Additionally, our properties are located in deepwater, which generally increases the capital and operating costs, technical challenges and risks associated with exploration and production activities. As a result, our exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of seismic data through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations.

Furthermore, the marketability of expected production from our prospects will also be affected by numerous factors. These factors include, but are not limited to, market fluctuations of oil and gas prices, proximity, capacity and availability of pipelines, the availability of processing facilities, equipment availability and government regulations (including, without limitation, regulations relating to prices, taxes, royalties, allowable production, importing and exporting of hydrocarbons, environmental, safety, health and climate change). The effect of these factors, individually or jointly, may result in us not receiving an adequate return on invested capital.

We are subject to drilling and other operational hazards.

The exploration and production business involves a variety of operating risks, including, but not limited to:

- blowouts, cratering and explosions;
- mechanical and equipment problems;
- uncontrolled flows or leaks of oil or well fluids, natural gas or other pollution;
- fires and gas flaring operations;
- marine hazards with respect to offshore operations;
- formations with abnormal pressures;
- pollution, other environmental risks and geological problems; and
- weather conditions and natural disasters.

These risks are particularly acute in deepwater drilling and exploration for natural resources. Any of these events could result in loss of human life, significant damage to property, environmental damage, impairment of our operations, delays in our drilling operations, increased costs and substantial losses. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. We do not carry business interruption insurance. The occurrence of any of these events, whether or not covered by insurance, could have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

We are members of several industry groups that provide general and specific oil spill and well containment resources in the U.S. Gulf of Mexico and offshore West Africa. Through these industry groups, as described under “Business—Containment Resources”, we have contractual rights to access certain oil spill and well containment resources. We can make no assurance that these resources will perform as designed or be able to fully contain or cap any oil spill, blow-out or uncontrolled flow of hydrocarbons. Furthermore, our contracts for the use of oil spill and well containment resources contain strict indemnity provisions that generally require us to indemnify the contractor for all losses incurred as a result of assisting us in our oil spill and well containment efforts, subject to certain exceptions and limitations. In the event we experience a subsea blowout, explosion, fire, uncontrolled flow of hydrocarbons or any of the other operational risks identified above, the oil spill and well containment resources which we have contractual rights to will not prevent us from incurring losses or shield us from liability, which could be substantial and have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

Our operations will involve special risks that could adversely affect operations.

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 our operations. As a result, we could incur substantial expenses that could reduce or eliminate capital and funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties.

Deepwater exploration generally involves greater operational and financial risks than onshore exploration or exploration in shallow waters. Deepwater drilling generally requires more time and more advanced drilling technologies, involving a higher risk of technological failure and usually higher drilling costs. Such risks are particularly applicable to our deepwater exploration efforts in the Inboard Lower Tertiary trend. In addition, there may be production risks of which we are currently unaware. Whether we use existing pipeline infrastructure, participate in the development of new subsea infrastructure or use floating production systems to transport oil from producing wells, if any, these operations may require substantial time for installation, or encounter mechanical difficulties and equipment failures that could result in significant cost overruns and delays. Furthermore, deepwater operations in the U.S. Gulf of Mexico generally lack the physical and oilfield service infrastructure present in shallower waters. As a result, a significant amount of time may elapse between a deepwater discovery and the marketing of the associated hydrocarbons, increasing both the financial and operational risk involved with these operations. Because of the lack and high cost of this infrastructure, oil and gas discoveries we make in the deepwater, if any, may never be economically producible.

In addition, in the event of a well control incident, containment and, potentially, cleanup activities for offshore drilling are costly. The resulting regulatory costs or penalties, and the results of third party lawsuits, as well as associated legal and support expenses, including costs to address negative publicity, could well exceed the actual costs of containment and cleanup. As a result, a well control incident could result in substantial liabilities for us, and have a significant negative impact on our earnings, cash flows, liquidity, financial position, and stock price.

Our operations in the U.S. Gulf of Mexico may be adversely impacted by tropical storms and hurricanes.

Tropical storms, hurricanes and the threat of tropical storms and hurricanes often result in the shutdown of operations in the U.S. Gulf of Mexico as well as operations within the path and the projected path of the tropical storms or hurricanes. In the future, during a shutdown period, we may be unable to access well sites and our services may be shut down. Additionally, tropical storms or hurricanes may cause evacuation of personnel and damage to offshore drilling rigs and other equipment, which may result in suspension of our operations. The shutdowns, related evacuations and damage can create unpredictability in activity and utilization rates, as well as delays and cost overruns, which may have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

The geographic concentration of our operations subjects us to an increased risk from factors specifically affecting those areas.

Our operations are currently concentrated in the deepwater U.S. Gulf of Mexico. Until the consummation of the Angola Transaction, we will also maintain operations offshore Angola. In addition, we have an interest in the Diaba Block offshore Gabon. Some or all of these properties could be affected should such regions experience:

- severe weather or natural disasters;
- moratoria on drilling or permitting delays;
- delays in or the inability to obtain regulatory approvals;
- delays or decreases in production;
- delays or decreases in the availability of drilling rigs and related equipment, facilities, personnel or services;

- delays or decreases in the availability of capacity to transport, gather or process production; and/or
- changes in the regulatory, political and fiscal environment.

For example, in response to the Deepwater Horizon incident in 2010, the U.S. government and its regulatory agencies with jurisdiction over oil and gas exploration, including the DOI, the BOEM and the BSEE, imposed moratoria on drilling operations, required operators to reapply for exploration plans and drilling permits and adopted extensive new regulations, which effectively had halted drilling operations in the deepwater U.S. Gulf of Mexico for a period of time. Additionally, oil and gas properties and facilities located in the U.S. Gulf of Mexico were significantly damaged by Hurricanes Katrina and Rita in 2005, which required our competitors to spend a significant amount of time and capital on inspections, repairs, debris removal, and the drilling of replacement wells. We maintain insurance coverage for only a portion of these risks. There also may be certain risks covered by insurance where the policy does not reimburse us for all of the costs related to a loss. We do not carry business interruption insurance.

Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties.

We are subject to regulatory risk in the U.S. Gulf of Mexico, and regulations enacted over the past several years may have significantly increased certain of the risks we face and increased the cost of operations in the U.S. Gulf of Mexico.

On April 20, 2010, the Transocean Deepwater Horizon, a semi-submersible offshore drilling rig operating in the deepwater U.S. Gulf of Mexico under contract to BP plc exploded, burned for two days and sank, resulting in loss of life, injuries and a large oil spill. The U.S. government and its regulatory agencies with jurisdiction over oil and gas exploration, including the DOI, the BOEM and the BSEE, responded to this incident by imposing moratoria on drilling operations and adopting numerous new regulations and new interpretations of existing regulations regarding operations in the U.S. Gulf of Mexico. Compliance with these new regulations and interpretations has increased the cost of our drilling operations in the U.S. Gulf of Mexico.

Assuming the Angola Transaction closes, our business will be almost entirely focused on the U.S. Gulf of Mexico. The successful execution of our U.S. Gulf of Mexico business plan depends on our ability to continue our exploration and appraisal efforts. A prolonged suspension of or delay in our drilling operations would adversely affect our business, financial position or future results of operations.

In particular, in April 2015 the BSEE proposed new well control regulations, which include more stringent design requirements and operational procedures for critical well control equipment, including those aimed at improving equipment reliability, regulating drilling margin and preventing blowouts, as well as reforms in well design, well control, casing, cementing, real-time well monitoring and subsea containment. Certain studies suggest that many wells drilled safely since 2010 could not be drilled as designed under the proposed regulations. If the rule were to be finalized as drafted, certain of our drilling operations may be delayed as required controls are implemented or may become infeasible or impossible due to the increased requirements.

Furthermore, the Deepwater Horizon incident has increased and may further increase certain of the risks we face, including, without limitation, the following:

- increased governmental regulation and enforcement of our and our industry's operations in a number of areas, including health and safety, financial responsibility, environmental, licensing, taxation, equipment specifications and inspections and training requirements;
- increased difficulty in obtaining leases and permits to drill offshore wells, including as a result of any bans or moratoria placed on offshore drilling;
- potential legal challenges to the issuance of permits and the conducting of our operations;
- higher drilling and operating costs;
- higher royalty rates and fees on leases acquired in the future;
- higher insurance costs, financial assurance requirements and increased potential liability thresholds under proposed legislation and regulations;

- decreased partner participation in wells we operate;
- higher capital costs as a result of any increase to the risks we or our industry face; and
- less favorable investor perception of the risk-adjusted benefits of deepwater offshore drilling.

The occurrence of any of these factors, or their continuation, could have a material adverse effect on our business, financial position or future results of operations.

We face various risks associated with increased activism against oil and gas exploration and development activities.

Opposition toward oil and gas drilling and development activity has been growing globally and is particularly pronounced in the United States. Companies in the oil and gas industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, human rights, environmental matters, sustainability, and business practices. Anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain operations such as offshore drilling and development. For example, environmental activists have recently challenged lease sales, seismic acquisition activities and decisions to grant air-quality permits in the U.S. Gulf of Mexico for offshore drilling.

Future activist efforts could result in the following:

- delay or denial of drilling permits;
- shortening of lease terms or reduction in lease size;
- restrictions or delays on our ability to obtain additional seismic data;
- restrictions on installation or operation of gathering, processing or production facilities;
- restrictions on the use of certain operating practices;
- legal challenges or lawsuits;
- damaging publicity about us;
- increased regulation;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties.

Our need to incur costs associated with responding to these initiatives or complying with any resulting new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations.

We may be exposed to liabilities under the U.S. Foreign Corrupt Practices Act, and any determination that we violated the U.S. Foreign Corrupt Practices Act could have a material adverse effect on our business.

We are subject to the U.S. Foreign Corrupt Practices Act ("FCPA") and other laws that prohibit improper payments or offers of payments to foreign governments and their officials and political parties for the purpose of obtaining or retaining business. We do business and may do additional business in the future in countries and regions in which we may face, directly or indirectly, corrupt demands by officials, tribal or insurgent organizations, or private entities. Thus, we face the risk of unauthorized payments or offers of payments by one of our employees or consultants, given that these parties may not always be subject to our control. Our existing safeguards and any future improvements may prove to be less than effective, and our employees and consultants may engage in conduct for which we might be held responsible.

In connection with entering into our RSAs for Blocks 9 and 21 offshore Angola, two Angolan-based E&P companies were assigned as part of the contractor group by the Angolan government. We had not worked with either of these companies in the past, and, therefore, our familiarity with these companies was limited. In the fall of 2010, we were made aware of allegations of a connection between senior Angolan government officials and one of these companies, Nazaki Oil and Gáz, S.A. ("Nazaki"), which was a full paying member of the contractor group but is no longer a member of such group. In March 2011, the SEC commenced an informal inquiry into these allegations. To avoid non-overlapping information requests, we voluntarily contacted the U.S. Department of Justice ("DOJ") with respect to the SEC's informal request and offered to respond to any requests the DOJ may have. Since such time, we have complied with all requests from the SEC and DOJ with respect to their inquiry. In November 2011, a formal order of investigation was issued by the SEC related to our operations in Angola. In August 2014, we received a Wells Notice from the SEC related to this investigation. In January 2015, we received a termination letter from the SEC advising us that the SEC's FCPA investigation has concluded and the Staff does not intend to recommend any enforcement action by the SEC. This letter formally concluded the SEC's investigation. We continue to cooperate with the DOJ with regard to its ongoing parallel investigation. We have conducted an extensive investigation into these allegations and believe that our activities in Angola have complied with all laws, including the FCPA. We are unable to predict the outcome of the DOJ's ongoing investigation or any action that the DOJ may decide to pursue, or otherwise provide any assurance regarding the duration, scope, developments in, results of or consequences of its investigation.

In the future, we may be partnered with other companies with whom we are unfamiliar. Violations of the FCPA may result in severe criminal or civil sanctions, and we may be subject to other liabilities, which could negatively affect our business, operating results and financial condition. In addition, the government may seek to hold us liable for successor liability FCPA violations committed by companies in which we invest or that we acquire.

A change in U.S. energy policy could have a significant impact on our operations and profitability.

U.S. energy policy and laws and regulations could change quickly, and substantial uncertainty exists about the nature of many potential rules and regulations that could impact the sources and uses of energy in the United States. For example, new CAFE standards enacted in 2012 have resulted in a significant increase in the fuel economy of cars and light trucks and have reduced the future demand for crude oil for road transport use. GHG emissions regulations may increase the demand for natural gas as fuel for power generation.

We design our exploration and development strategy and related capital investment programs years in advance. As a result, we are impacted in our ability to plan, invest and respond to potential changes in our business. This can result in a reduction of our cash flows and profitability to the extent we are unable to respond to sudden or significant changes in our operating environment due to changes in U.S. energy policy.

Our need to incur costs associated with responding to these initiatives or complying with any resulting new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations.

We operate in a litigious environment.

Some of the jurisdictions within which we operate have proven to be litigious environments. Oil and gas companies, such as us, can be involved in various legal proceedings, such as title, royalty, or contractual disputes, in the ordinary course of business.

We are currently, and from time to time we may become, involved in various legal and regulatory proceedings arising in the normal course of business. See "Legal Proceedings." We are vigorously defending against the current lawsuits and do not believe they will have a material adverse effect on our business. However, we cannot predict the occurrence or outcome of these proceedings with certainty, and if we are unsuccessful in these litigations and any loss exceeds our available insurance, this could have a material adverse effect on our results of operations.

Because we maintain a diversified portfolio of assets that includes both U.S. and international projects, the complexity and types of legal proceedings with which we may become involved may vary, and we could incur significant legal and support expenses in different jurisdictions. If we are not able to successfully defend ourselves, there could be a delay or even halt in our exploration, development or production activities or other business plans, resulting in a reduction in reserves, loss of production and reduced cash flows. Legal proceedings could result in a substantial liability and/or negative publicity about us and adversely affect the price of our common stock. In addition, legal proceedings distract management and other personnel from their primary responsibilities.

Our operations may be adversely affected by political and economic circumstances in the countries in which we operate.

Our oil and gas exploration, development and production activities are subject to political and economic uncertainties (including but not limited to changes, sometimes frequent or marked, in energy policies or the personnel administering them), expropriation of property, cancellation or modification of contract rights, changes in laws and policies governing operations of foreign-based companies, unilateral renegotiation of contracts by governmental entities, redefinition of international boundaries or boundary disputes, foreign exchange restrictions, currency fluctuations, royalty and tax increases and other risks arising out of governmental sovereignty over the areas in which our operations are conducted, as well as risks of loss due to civil strife, acts of war, acts of terrorism, piracy, disease, guerrilla activities, insurrection and other political risks, including tension and confrontations among political parties. Some of these risks may be higher in the developing countries in which we conduct our activities, namely, Angola and Gabon.

Our operations are exposed to risks of war, local economic conditions, political disruption, civil disturbance and governmental policies that may:

- disrupt our operations;
- restrict the movement of funds or limit repatriation of profits;
- in the case of our non-U.S. operations, lead to U.S. government or international sanctions; and
- limit access to markets for periods of time.

Disruptions may occur in the future, and losses caused by these disruptions may occur that will not be covered by insurance. Consequently, our exploration, development and production activities may be substantially affected by factors which could have a material adverse effect on our financial condition and results of operations. Furthermore, in the event of a dispute arising from non-U.S. operations, we may be subject to the exclusive jurisdiction of courts outside the U.S. or may not be successful in subjecting non-U.S. persons to the jurisdiction of courts in the U.S., which could adversely affect the outcome of such dispute.

Our operations may also be adversely affected by laws and policies of the jurisdictions, including Angola, Gabon, the United States, the Cayman Islands and other jurisdictions, in which we do business, that affect foreign trade and taxation. Changes in any of these laws or policies or the implementation thereof, could have a material adverse effect on our results of operations and financial position, as well as on the market price of our common stock.

The oil and gas industry, including the acquisition of exploration acreage worldwide, is intensely competitive.

The international oil and gas industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of oil and gas. We operate in a highly competitive environment for acquiring exploration acreage and hiring and retaining trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than us, which can be particularly important in the areas in which we operate. These companies may be able to pay more for productive or prospective properties and prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Furthermore, these companies may also be better able to withstand the financial pressures of unsuccessful drill attempts, delays, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position. Our ability to acquire additional exploration prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for available capital for investment in the oil and gas industry. As a result of these and other factors, we may not be able to compete successfully in an intensely competitive industry, which could have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

Participants in the oil and gas industry are subject to complex laws that can affect the cost, manner or feasibility of doing business.

Exploration and production activities in the oil and gas industry are subject to extensive local, state, federal and international regulations. We may be required to make large expenditures to comply with governmental regulations, particularly in respect of the following matters:

- licenses and leases for drilling operations;
- foreign exchange and banking;
- royalty increases, including retroactive claims;
- drilling and development bonds and social payment obligations;
- reports concerning operations;
- the spacing of wells;
- unitization of oil accumulations;
- environmental remediation or investigation; and
- taxation.

Under these and other laws and regulations, we could be liable for personal injuries, property damage and other types of damages for which we may not maintain, or otherwise be protected by, insurance coverage. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

For example, until the closing of the Angola Transaction and the cessation of our operations within Angola, we will be subject to the Foreign Exchange Law for the Petroleum Sector, which requires, among other things, that all foreign exchange operations be carried out through Angolan banks, that oil and gas exploration and production companies open local bank accounts in foreign currencies in order to pay local taxes and to pay for goods and services supplied by non-resident suppliers and service providers, and also that oil and gas exploration and production companies open local bank accounts in local currency in order to pay for goods and services supplied by resident suppliers and service providers. See “Business—Laws and Regulations of Angola and Gabon—Angola” for more information. These new rules require additional compliance efforts and costs on our and other industry participants’ part, and may in some cases cause delay or other issues in connection with the acquisition of or payments for goods and services. As a result of the significant downturn in oil and gas prices and recent devaluation of the Angola kwanza versus the U.S. dollar, it has become more difficult to conduct foreign currency transactions in Angola. Any of these consequences could have a material adverse effect on our results of operations.

We may be subject to risks in connection with acquisitions and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of prospects and licenses, reserves and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of these assets requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs; and
- potential environmental, safety, health and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject assets that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the assets to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We may not be entitled to contractual indemnification for environmental, safety, and health liabilities and could acquire assets on an "as is" basis. Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;

- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;

- difficulty associated with coordinating geographically separate organizations; and

- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating 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 significant business activities are interrupted as a result of the integration process, our business could suffer.

If we fail to realize the anticipated benefits of a significant acquisition, our results of operations may be adversely affected.

The success of a significant acquisition will depend, in part, on our ability to realize anticipated growth opportunities from combining the acquired assets or operations with those of ours. Even if a combination is successful, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, increased interest expense associated with debt incurred or assumed in connection with the transaction, adverse changes in oil and gas industry conditions, or by risks and uncertainties relating to the exploration prospects of the combined assets or operations, or an increase in operating or other costs or other difficulties, including the assumption of environmental, safety and health or other liabilities in connection with the acquisition. If we fail to realize the benefits we anticipate from an acquisition, our results of operations may be adversely affected.

A cyber incident 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, conduct reservoir modeling and reserves estimation, and to process and record financial and operating data.

We depend on digital technology, including information systems and related infrastructure as well as cloud application and services, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate 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 explore for and develop oil and gas in increasingly difficult physical environments, such as below-salt deepwater, 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. For example, in 2012, a wave of network attacks impacted Saudi Arabia's oil industry and breached financial institutions in the US. 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.

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. Although to date we have not experienced any cyber-attacks, there can be no assurance that we will not be the target of cyber-attacks in the future or suffer such losses related to any cyber-incident. 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.

We and our operations are subject to numerous environmental, health and safety regulations which may result in material liabilities and costs.

We are, and our future operations will be, subject to various international, foreign, federal, state and local environmental, health and safety laws and regulations governing, among other things, the emission and discharge of pollutants into the ground, air or water, the generation, storage, handling, use and transportation of regulated materials and the health and safety of our employees. We are required to obtain various environmental permits from governmental authorities for our operations, including drilling permits for our wells. There is a risk that we have not been or will not be at all times in complete compliance with these permits and the environmental laws and regulations to which we are subject. If we violate or fail to comply with these laws, regulations or permits, we could be fined or otherwise sanctioned by regulators, including through the revocation of our permits or the suspension or termination of our operations. If we fail to obtain permits in a timely manner or at all (due to opposition from community or environmental interest groups, governmental delays, changes in laws or the interpretation thereof or any other reasons), such failure could impede our operations, which could have a material adverse effect on our results of operations and our financial condition.

We, as the named lessee or as the designated operator under our current and future oil leases and licenses, could be held liable for all environmental, health and safety costs and liabilities arising out of our actions and omissions as well as those of our third-party contractors. To the extent we do not address these costs and liabilities or if we are otherwise in breach of our lease or license requirements, our leases or licenses could be suspended or terminated. We have contracted with and intend to continue to hire third parties to perform the majority of the drilling and other services related to our operations. There is a risk that we may contract with third parties with unsatisfactory environmental, health and safety records or that our contractors may be unwilling or unable to cover any losses associated with their acts and omissions. Accordingly, we could be held liable for all costs and liabilities arising out of the acts or omissions of our contractors, which could have a material adverse effect on our results of operations and financial condition.

As the designated operator of certain of our leases and licenses, we are required to maintain bonding or insurance coverage for certain risks relating to our operations, including environmental risks. We maintain insurance at levels that we believe are consistent with current industry practices, but we are not fully insured against all risks. Our insurance may not cover any or all environmental claims that might arise from our operations or those of our third-party contractors. If a significant accident or other event occurs and is not fully covered by our insurance, or our third-party contractors have not agreed to bear responsibility, such accident or event could have a material adverse effect on our results of operations and our financial condition. In addition, we may not be able to obtain required bonding or insurance coverage at all or in time to meet our anticipated startup schedule for each well, and if we fail to obtain this bonding or coverage, such failure could have a material adverse effect on our results of operations and financial condition.

Releases to deepwater of regulated substances are common, and under certain environmental laws, we could be held responsible for all of the costs relating to any contamination caused by us or our contractors, at our facilities and at any third party waste disposal sites used by us or on our behalf. These costs could be material. In addition, offshore oil exploration and production involves various hazards, including human exposure to regulated substances, including naturally occurring radioactive materials. As such, we could be held liable for any and all consequences arising out of human exposure to such substances or other damage resulting from the release of regulated substances to the environment, endangered species, property or to natural resources.

Particularly since the Deepwater Horizon event in the U.S. Gulf of Mexico in 2010, there has been an increased interest in making regulation of deepwater oil and gas exploration and production more stringent in the U.S. If adopted, certain proposals such as a significant increase or elimination of financial liability caps for economic damages, could significantly raise daily penalties for infractions and require significantly more comprehensive financial assurance requirements under OPA which could affect our results of operations and our financial condition.

In addition, we expect continued attention to climate change issues. Various countries and U.S. states and regions have agreed to regulate emissions of greenhouse gases ("GHGs"), including methane (a primary component of natural gas) and carbon dioxide, a byproduct of oil and natural gas combustion. Additionally, the U.S. Congress has in the past and may in the future consider legislation requiring reductions in GHG emissions. The EPA began regulating GHG emissions from certain stationary sources in January 2011 and has enacted GHG emissions standards for certain classes of vehicles. The EPA has adopted rules requiring the reporting of GHG emissions, including from certain offshore oil and natural gas production facilities on an annual basis. In addition, in accordance with the Obama Administration's June 2013 Climate Action Plan ("CAP"), the EPA finalized the Clean Power Plan in August 2015, which sets forth binding guidelines for GHG emissions from existing power plants, as well as rules relating to GHG emissions from new, modified and reconstructed power plants. The EPA is also required pursuant to a settlement agreement to issue GHG emissions standards for oil refineries, but no such standards have been proposed to date. The CAP also calls upon EPA and other governmental agencies to identify ways in which to reduce methane emissions from various sectors, including the oil and gas industry. In addition, in August 2015 the EPA proposed new regulations to reduce methane emissions from oil and gas operations in an effort to reduce methane emissions from the oil and gas sector by up to forty-five percent by 2025. The EPA is also expected to expand the GHG Reporting Rule to cover all segments of the oil and gas industry. Additionally, the EPA and the National Highway Traffic Safety Administration administer GHG emissions standards for heavy, medium and light duty vehicles, which have become increasingly stringent over time. The regulation of GHGs and the physical impacts of climate change in the areas in which we, our customers and the end-users of our products operate could adversely impact our operations and the demand for our products.

Environmental, health and safety laws are complex, change frequently and have tended to become increasingly stringent over time. Our costs of complying with current and future environmental, health and safety laws, and our liabilities arising from releases of, or exposure to, regulated substances may adversely affect our results of operations and our financial condition. See "Business—Environmental Matters and Regulation."

Non-U.S. holders of our common stock, in certain situations, could be subject to U.S. federal income tax upon the sale, exchange or other disposition of our common stock.

Our assets consist primarily of interests in U.S. oil and gas properties (which constitute U.S. real property interests for purposes of determining whether we are a U.S. real property holding corporation) and interests in non-U.S. oil and gas properties, the relative values of which at any time may be uncertain and may fluctuate significantly over time. Therefore, we may be, now or at any time while a non-U.S. investor owns our common stock, a U.S. real property holding corporation. As a result, under the Foreign Investment in Real Property Tax Act ("FIRPTA"), certain non-U.S. investors may be subject to U.S. federal income tax on gain from the disposition of shares of our common stock, in which case they would also be required to file U.S. tax returns with respect to such gain. Whether these FIRPTA provisions apply depends on the amount of our common stock that such non-U.S. investors hold and whether, at the time they dispose of their shares, our common stock is regularly traded on an established securities market (such as the New York Stock Exchange ("NYSE")) within the meaning of the applicable Treasury Regulations. So long as our common stock is listed on the NYSE, only a non-U.S. investor who has held, actually or constructively, more than 5% of our common stock may be subject to U.S. federal income tax on the disposition of our common stock under FIRPTA.

We may incur substantial losses and become subject to liability claims for which we may not have adequate insurance coverage.

Several external factors could arise which would significantly impact our ability to effectively insure our oil and natural gas exploration and development operations. Should legislation be passed to increase the minimum insurance limit of the OSFR policy required for future U.S. Gulf of Mexico oil and natural gas exploration, there is no assurance that we will be able to obtain this insurance. The insurance markets may not provide products to financially insure us against all operational risks. For instance, civil and criminal penalties for environmental pollution can be very severe and may not be insurable. For some risks, we may not obtain insurance if we believe the market price of available insurance is excessive or prohibitive relative to the risks presented. For instance, we do not purchase business interruption or wind insurance due to the market pricing.

Even when insurance is purchased, exclusions in coverage, unanticipated circumstances and potentially large indemnity obligations may have a material adverse effect on our operations and financial condition. The continuation of the recent severe declines in oil and gas prices has had a negative impact on the foreign currency exchange market for the Angola Kwanza, which in turn has made it more difficult for our insurance provider in Angola to obtain foreign currency in an amount sufficient to procure adequate re-insurance. The inability of our insurance provider to obtain adequate re-insurance may jeopardize our insurance coverage or otherwise impair its ability to perform its obligations under our insurance policies and agreements. Because third-party contractors and other service providers are used in our offshore operations, we may not realize the intended protections of worker's compensation laws in dealing with their employees. Generally, under our contracts with drilling and other oilfield service contractors, we are obligated, subject to certain exceptions and limitations, to indemnify such contractors for all claims arising out of damage to our property, injury or death to our employees and pollution emanating from the well-bore, including pollution resulting from blow-outs and uncontrolled flows of hydrocarbons.

In addition, even when insurance is purchased, we may encounter disputes with our insurance providers concerning coverage and such providers may attempt to deny coverage. For example, certain of our insurance providers are disputing coverage for certain expenses and potential liabilities, including with respect to our current shareholder litigation matters. We are enforcing our rights to coverage pursuant to our insurance agreements with these insurance providers and believe such expenses and potential liabilities are covered by such insurance, within certain thresholds. Should we be unsuccessful in enforcing rights under our insurance agreements, should we breach the terms of our insurance agreements or should such insurance agreements not provide the coverage we believed to be in place, any losses we incur which are not covered wholly or partially by insurance could have a material adverse effect on our results of operations and financial condition.

We may be required to pay a material cash sum to Whitton Petroleum Services Limited ("Whitton") in connection with the closing of the sale of our interests in Blocks 20 and 21 offshore Angola.

On February 13, 2009, we entered into a restated overriding royalty agreement (the "Royalty Agreement") with Whitton. Pursuant to the terms of the Royalty Agreement, in consideration for Whitton's consulting services in connection with Blocks 9, 20 and 21 offshore Angola and our business and operations in Angola, Whitton is to receive quarterly payments (measured in U.S. Dollars) equal to 2.5% of the market price of our share of the crude oil produced in such quarter and not used in petroleum operations, less the cost recovery crude oil, assuming the applicable government contract is a production sharing agreement. If the applicable government contract is a risk services agreement and not a production sharing agreement (which is the case with respect to Blocks 9 and 21), pursuant to the Royalty Agreement, we have undertaken to agree with Whitton an economic model (the "RSA Economic Model") containing terms equivalent to those in such risk services agreement and using actual production and costs. The RSA Economic Model has not yet been agreed with Whitton. If we assign all of our interests in such Blocks, Whitton may, depending on the option we elect, have the right to receive the market value of its rights and obligations under the Royalty Agreement, based upon the amount in cash a willing transferee of such rights and obligations would pay a willing transferor in an arm's length transaction. Given potential issues regarding how such market value of Whitton's rights and obligations under the Royalty Agreement could be calculated, including, without limitation, outstanding issues related to the RSA Economic Model, the amount of any such payment that could be owed to Whitton upon consummation of the sale of our interests in Blocks 20 and 21 offshore Angola is uncertain, but may be significant. Resolution of any such payment may include an expert determination of such cash value payment. We can make no assurance that any results from an expert determination process will be favorable to us. If we are ultimately required to pay a significant sum under the Royalty Agreement, our business and financial condition could be adversely affected.

The conditional conversion feature of our 3.125% senior convertibles notes due 2024, if triggered, may adversely affect our financial condition and operating results.

If the conditional conversion feature of our 3.125% senior convertibles notes due 2024 is triggered, holders of such notes will be entitled to convert these notes at any time during specified periods outlined in the indenture governing such notes, at their option. If one or more holders elect to convert their notes, unless we elect to satisfy our conversion obligation by delivering solely shares of our common stock (other than cash in lieu of any fractional share), we would be required to settle a portion or all of our conversion obligation through the payment of cash, which could adversely affect our liquidity. In addition, even if holders do not elect to convert their notes, we could be required under applicable accounting rules to reclassify all or a portion of the outstanding principal of these notes as a current rather than long-term liability, which would result in a material reduction of our net working capital.

Conversions of the notes may adversely affect our financial condition and operating results.

Holders of notes will be entitled to convert the notes at their option at any time up until the maturity date, being December 1, 2019 for the 2.625% convertible senior notes due 2019 and May 15, 2024 for the 3.125% senior convertible notes due 2024. If one or more holders elect to convert their notes, unless we elect to satisfy our conversion obligation by delivering solely shares of our common stock (other than cash in lieu of any fractional share), we would be required to settle a portion or all of our conversion obligation through the payment of cash, which could adversely affect our liquidity. In addition, even if holders do not elect to convert their notes, we could be required under applicable accounting rules to reclassify all or a portion of the outstanding principal of the notes as a current rather than long-term liability, which would result in a material reduction of our net working capital.

The accounting method for convertible debt securities that may be settled in cash, such as the notes, could have a material effect on our reported financial results.

Under Accounting Standards Codification 470-20, Debt with Conversion and Other Options, which we refer to as ASC 470-20, an entity must separately account for the liability and equity components of the convertible debt instruments (such as the notes) that may be settled entirely or partially in cash upon conversion in a manner that reflects the issuer's economic interest cost. The effect of ASC 470-20 on the accounting for the notes is that the equity component is required to be included in the additional paid-in capital section of stockholders' equity on our consolidated balance sheet, and the value of the equity component would be treated as original issue discount for purposes of accounting for the debt component of the notes. As a result, we will be required to record a greater amount of non-cash interest expense in current periods presented as a result of the amortization of the discounted carrying value of the notes to their face amount over the term of the notes. We will report lower net income in our financial results because ASC 470-20 will require interest to include both the current period's amortization of the debt discount and the instrument's coupon interest, which could adversely affect our reported or future financial results, the trading price of our common stock and the trading price of the notes.

We may account for the notes utilizing the treasury stock method. The effect of this method is that the shares issuable upon conversion of convertible securities are not included in the calculation of diluted earnings per share except to the extent that the conversion value of such securities exceeds their principal amount. Under the treasury stock method, for diluted earnings per share purposes, the notes would be accounted for as if the number of shares of common stock that would be necessary to settle such excess, if we elected to settle such excess in shares, are issued.

However, we cannot be sure that the accounting standards in the future will continue to permit the use of the treasury stock method. If we are unable to use the treasury stock method in accounting for the shares issuable upon conversion of the notes, for whatever reason, then we would have to apply the if-converted method, the effect of which is that conversion will not be assumed for purposes of computing diluted earnings per share if the effect would be antidilutive. Under the if-converted method, for diluted earnings per share purposes, convertible debt is antidilutive whenever its interest, net of tax and nondiscretionary adjustments, per common share obtainable on conversion exceeds basic earnings per share. Dilutive securities that are issued during a period and dilutive convertible securities for which conversion options lapse, or for which related debt is extinguished during a period, will be included in the denominator of diluted earnings per share for the period that they were outstanding. Likewise, dilutive convertible securities converted during a period will be included in the denominator for the period prior to actual conversion. Moreover, interest charges applicable to the convertible debt will be added back to the numerator.

The borrowing base under our Heidelberg reserve-based loan facility will likely be substantially reduced in the near future, which could negatively impact our funding for future development drilling at Heidelberg.

The borrowing base under our Heidelberg reserve-based loan facility will likely be substantially reduced in the near future depending upon the level of oil and gas prices and the performance of the producing wells and production facilities associated with the Heidelberg field. The Heidelberg field started producing oil and gas in January 2016 and the performance of its producing wells is uncertain. The amount available for borrowing at any one time under the Heidelberg reserve-based loan facility is limited to a borrowing base amount determined twice a year using agreed projections by applying the lower of (i) a project life coverage ratio of 1.5:1.0 to the sum of discounted projected net revenues from the Heidelberg field and certain capital expenditures and (ii) a loan life coverage ratio of 1.3:1.0 to the sum of discounted projected net revenues from the Heidelberg field and certain capital expenditures. Interim borrowing base redeterminations can take place between scheduled redetermination dates in limited circumstances specified in the facility agreement.

Our next redetermination will occur in March 2016 and our borrowing base will likely be substantially reduced. In the event the amount outstanding under our Heidelberg reserve-based loan facility at any time exceeds the borrowing base at such time, we may be required to repay a portion of our outstanding borrowings. Currently, we have not borrowed any amounts under our Heidelberg reserve-based loan facility. If the borrowing base under our Heidelberg reserve-based loan facility is reduced, this could have an adverse effect on our liquidity and financial condition and could negatively impact funding for future development drilling at Heidelberg.

Risks Relating to our Common Stock

Our stock price may be volatile, and investors in our common stock could incur substantial losses.

Our stock price may be volatile. The stock market in general has experienced extreme volatility that has often been unrelated to the operating performance of particular companies. The market price for our common stock may be influenced by many factors, including, but not limited to:

- the timing or occurrence of the closing of the sale of our interests in Block 20 and 21 offshore Angola;
- the price of oil and natural gas;
- the success of our development and production operations, and the marketing of any oil and gas we produce;
- to what extent our exploration wells are successful;
- regulatory developments in the United States and foreign countries where we operate;
- the recruitment or departure of key personnel;
- quarterly or annual variations in our financial results or those of companies that are perceived to be similar to us;
- market conditions in the industries in which we compete and issuance of new or changed securities;

- increases in operating costs, including cost overruns associated with our exploration and development activities;
- analysts' reports or recommendations;
- the failure of securities analysts to cover our common stock or changes in financial estimates by analysts;
- the inability to meet the financial estimates of analysts who follow our common stock;
- the issuance or sale of any additional securities of ours;
- investor perception of our company and of the industry in which we compete and areas in which we operate; and
- general economic, political and market conditions.

A substantial portion of our total outstanding shares may be sold into the market at any time. This could cause the market price of our common stock to drop significantly, even if our business is doing well.

All of the shares sold in our public offerings are freely tradable without restrictions or further registration under the federal securities laws, unless purchased by our "affiliates" as that term is defined in Rule 144 under the Securities Act of 1933, as amended (the "Securities Act"). Substantially all the remaining shares of common stock are restricted securities as defined in Rule 144 under the Securities Act. Restricted securities may be sold in the U.S. public market only if registered or if they qualify for an exemption from registration, including by reason of Rules 144 or 701 under the Securities Act. All of our restricted shares are eligible for sale in the public market, subject in certain circumstances to the volume, manner of sale limitations with respect to shares held by our affiliates, and other limitations under Rule 144. Additionally, we have registered all shares of our common stock that we may issue under our employee and director benefit plans. These shares can be freely sold in the public market upon issuance, unless pursuant to their terms these stock awards have transfer restrictions attached to them. Sales of a substantial number of shares of our common stock, or the perception in the market that the holders of a large number of shares intend to sell shares, could reduce the market price of our common stock.

Conversion of the notes may dilute the ownership interest of existing stockholders, including holders who have previously converted their notes.

The conversion of some or all of the notes may dilute the ownership interests of existing stockholders. Any sales in the public market of any shares of our common stock issuable upon such conversion could adversely affect prevailing market prices of our common stock. In addition, the anticipated conversion of the notes into shares of our common stock or a combination of cash and shares of our common stock could depress the price of our common stock.

Holders of our common shares will be diluted if additional shares are issued.

We may issue additional shares of common stock, preferred stock, warrants, rights, units and debt securities for general corporate purposes, including, but not limited to, repayment or refinancing of borrowings, working capital, capital expenditures, investments and acquisitions. We may issue additional shares of common stock in connection with complementary or strategic acquisitions of assets or businesses. We also issue restricted stock to our executive officers, employees and independent directors as part of their compensation. If we issue additional shares of common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Ownership of our capital stock is concentrated among our largest stockholders and their affiliates.

A small number of stockholders hold a majority of our common stock. These stockholders have influence over all matters that require approval by our stockholders, including the election of directors and approval of significant corporate transactions. This concentration of ownership may limit your ability to influence corporate matters, and as a result, actions may be taken that you may not view as beneficial. Furthermore, these stockholders may sell their shares of common stock at any time. Such sales could be substantial and adversely affect the market price of our common stock.

Provisions of our certificate of incorporation and by-laws could discourage potential acquisition proposals and could deter or prevent a change in control.

Some provisions in our certificate of incorporation and by-laws, as well as Delaware statutes, may have the effect of delaying, deferring or preventing a change in control. These provisions, including those providing for the possible issuance of shares of our preferred stock and the right of the board of directors to amend the by-laws, may make it more difficult for other persons, without the approval of our board of directors, to make a tender offer or otherwise acquire a substantial number of shares of our common stock or to launch other takeover attempts that a stockholder might consider to be in his or her best interest. These provisions could limit the price that some investors might be willing to pay in the future for shares of our common stock.

Provisions of the notes could discourage an acquisition of us by a third party.

Certain provisions of the notes could make it more difficult or more expensive for a third party to acquire us, or may even prevent a third party from acquiring us. For example, upon the occurrence of a fundamental change, holders of the notes will have the right, at their option, to require us to repurchase all of their notes or any portion of the principal amount of such notes in integral multiples of $1,000. In addition, the acquisition of us by a third party could require us, under certain circumstances, to increase the conversion rate for a holder who elects to convert its notes in connection with such acquisition. By discouraging an acquisition of us by a third party, these provisions could have the effect of depriving the holders of our common stock of an opportunity to sell their common stock at a premium over prevailing market prices.

We do not intend to pay dividends on our common shares and, consequently, your only opportunity to achieve a return on your investment is if the price of our shares appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Consequently, investors must rely on sales of their shares of common stock after price appreciation, which may never occur, as the only way to realize a return on their investment.

Item 1B. *Unresolved Staff Comments*

Not applicable.

Item 2. *Properties*

Please refer to the information under the caption “Business” in this Annual Report on Form 10-K.

Item 3. *Legal Proceedings*

We are currently, and from time to time we may become, involved in various legal and regulatory proceedings arising in the normal course of business.

On November 30, 2014, two purported stockholders, St. Lucie County Fire District Firefighters’ Pension Trust Fund and Fire and Police Retiree Health Care Fund, San Antonio, filed a class action lawsuit in the U.S. District Court for the Southern District of Texas on behalf of a putative class of all purchasers of our securities from February 21, 2012 through November 4, 2014 (the “St. Lucie lawsuit”). The St. Lucie lawsuit, filed against us and certain officers, former and current members of the Board of Directors, underwriters, and investment firms and funds, asserted violations of federal securities laws based on alleged misrepresentations and omissions in SEC filings and other public disclosures, primarily regarding compliance with the U.S. Foreign Corrupt Practices Act (“FCPA”) in our Angolan operations and the performance of certain wells offshore Angola. On December 4, 2014, Steven Neuman, a purported stockholder, filed a substantially similar lawsuit against us and certain of our officers in the U.S. District Court for the Southern District of Texas on behalf of a putative class of all purchasers of our securities from February 21, 2012 through August 4, 2014 (the “Neuman lawsuit”). Like the St. Lucie lawsuit, the Neuman lawsuit asserted violations of federal securities laws based on alleged misrepresentations and omissions in SEC filings and other public disclosures regarding our compliance with the FCPA in our Angolan operations. On March 3, 2015, the Court entered an order consolidating the Neuman lawsuit with the St. Lucie lawsuit. The consolidated matter is captioned In re Cobalt International Energy, Inc. Securities Litigation (the “Consolidated Action”). The same day, the Court also entered an order in the Consolidated Action appointing Lead Plaintiffs and Lead Counsel. Lead Plaintiffs filed their consolidated amended complaint on May 1, 2015. Among other remedies, the Consolidated Action seeks damages in an unspecified amount, along with an award of attorney fees and other costs and expenses to the plaintiffs. We filed a motion to dismiss the consolidated amended complaint on June 30, 2015, and the other defendants also filed motions to dismiss. On January 19, 2016, the Court denied our motion to dismiss. On February 3, 2016, we filed a motion requesting that the

Court certify its order on the motions to dismiss so that we may seek interlocutory appellate review of the order; the other defendants also filed motions requesting certification. The matter remains ongoing.

On January 16, 2015, Edward Ogden, a purported stockholder, filed a derivative action in the U.S. District Court for the Southern District of Texas against us, as a nominal defendant, and certain of our officers and former and current directors. The plaintiff filed an amended complaint on April 23, 2015. The lawsuit alleges that the individual defendants breached their fiduciary duties and violated federal securities laws based on alleged misrepresentations and omissions in SEC filings and other public disclosures, including in relation to compliance with the FCPA in our Angolan operations and regarding the performance of certain wells offshore Angola. The lawsuit further alleges that certain officers received performance-based compensation in excess of what they were entitled and that certain officers and directors engaged in unlawful trading. The lawsuit also alleges that the plaintiff was excused from making a demand upon our board to bring the claims on the basis of futility. The plaintiff asserts claims for breach of fiduciary duty, unjust enrichment, and corporate waste. The plaintiff seeks damages in an unspecified amount, disgorgement of profits, appropriate equitable relief, and an award of attorney fees and other costs and expenses. We filed a motion to dismiss the amended complaint on June 22, 2015 for failure to make demand upon our board and to adequately plead standing. The Court granted our motion on November 25, 2015, dismissing the case without prejudice but granting the plaintiff leave to amend his complaint. The plaintiff's deadline to file an amended complaint was January 8, 2016. The plaintiff did not file an amended complaint by the Court's deadline. On February 2, 2016, the Court entered an order dismissing the lawsuit.

We are vigorously defending against the current lawsuits and do not believe they will have a material adverse effect on our business. However, we cannot predict the occurrence or outcome of these proceedings with certainty, and if we are unsuccessful in these litigations and any loss exceeds our available insurance, this could have a material adverse effect on our results of operations. For more information, see "Risk Factors—Risks Related to Our Business—We operate in a litigious environment."

Item 4. *Mine Safety Disclosures*

Not applicable.

PART II

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

Market Information

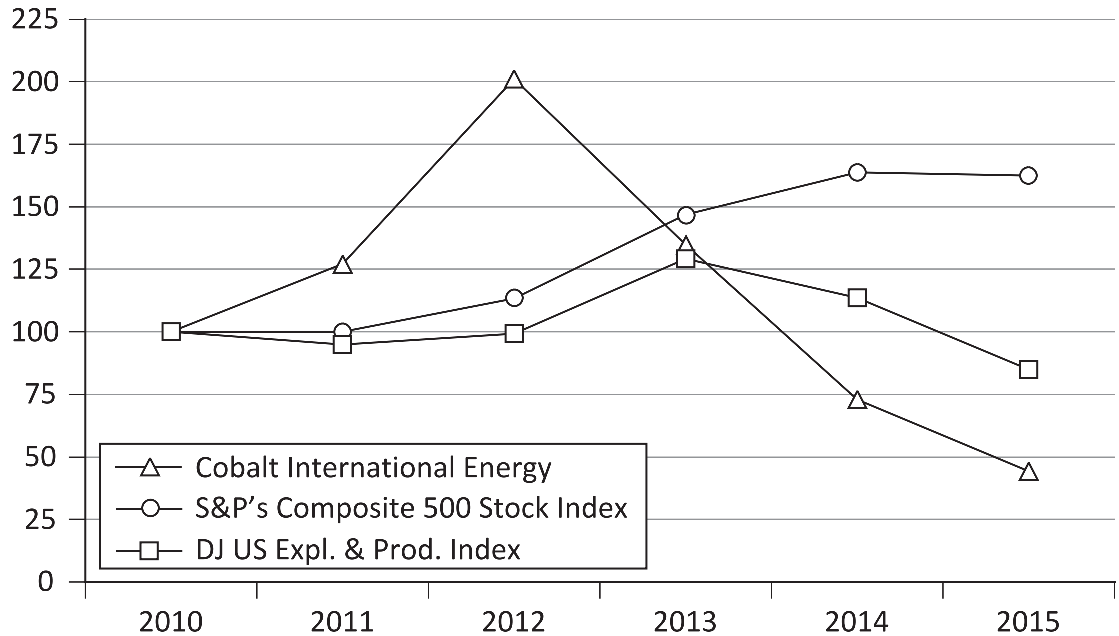
Our common stock is traded on the NYSE under the symbol "CIE." On January 29, 2016, the last reported sale price for our common stock on NYSE was $3.79 per share. The following table sets forth, for the periods indicated, the reported high and low sale prices for our common stock on the NYSE.

	High	Low
Year ending December 31, 2016		
First Quarter (through January 29, 2016)	$ 5.38	$ 2.93
Year ended December 31, 2015		
Fourth Quarter	$ 9.43	$ 5.14
Third Quarter	9.82	6.73
Second Quarter	11.20	9.38
First Quarter	10.24	7.73
Year ended December 31, 2014		
Fourth Quarter	$ 13.76	$ 7.40
Third Quarter	18.42	13.38
Second Quarter	19.77	16.90
First Quarter	19.90	15.36

Performance Graph

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that we specifically incorporate it by reference into such filing.

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the appreciation of our common stock relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance. The graph compares the yearly percentage change in the cumulative total stockholder return on our common stock with the cumulative total return of the Standard & Poor's Composite 500 Stock Index and of the Dow Jones U.S. Exploration & Production Index (formerly Dow Jones Secondary Oil Stock Index) from December 16, 2010, the date we commenced trading on the New York Stock Exchange, through December 31, 2015.



An investment of $100 is assumed to have been made in our common stock, in the S&P's Composite 500 Stock Index (with reinvestment of all dividends) and in the Dow Jones U.S. Exploration & Production Index on December 16, 2010, and its relative performance is tracked through December 31, 2015:

	Year Ended December 31,					
	2010	2011	2012	2013	2014	2015
Cobalt International Energy, Inc.	$ 100.00	$ 127.11	$ 201.15	$ 134.73	$ 72.81	$ 44.23
S&P's Composite 500 Stock Index.......................	100.00	100.00	113.40	146.97	163.71	162.52
Dow Jones U.S. Exploration & Production Index...	100.00	95.00	99.36	129.29	113.63	85.03

Holders

As of December 31, 2015, there were approximately 194 holders of record of our common stock. The number of record holders does not include holders of shares in "street names" or persons, partnerships, associations, corporations or other entities identified in security position listings maintained by depositories.

Dividend Policy

At the present time, we intend to retain all of our future earnings, if any, generated by our operations for the development and growth of our business. The decision to pay dividends on our common stock is at the discretion of our board of directors and depends on our financial condition, results of operations, capital requirements and other factors that our board of directors deems relevant.

Equity Compensation Plan

For information on securities authorized under our equity compensation plans, see the section entitled “Executive Compensation—Equity Compensation Plan Information” in our definitive Proxy Statement for our annual meeting of stockholders to be held on April 28, 2016.

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

The selected historical financial information set forth below should be read in conjunction with “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and with our financial statements and the notes to those financial statements included elsewhere in this Annual Report on Form 10-K. The consolidated statements of operations information for the years ended December 31, 2015, 2014, 2013, 2012, and 2011 were derived from Cobalt International Energy, Inc.’s audited financial statements.

Consolidated Statement of Operations Information:

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	($ in thousands except per share data)				
Oil and gas revenue	$ —	$ —	$ —	$ —	$ —
Operating costs and expenses					
Seismic and exploration	45,318	41,431	49,847	34,238	13,655
Dry hole expense and impairment	308,960	133,223	224,105	134,085	23,323
General and administrative	87,031	72,090	72,895	63,592	45,776
Accretion expense	99	—	—		
Depreciation and amortization	1,403	1,694	1,328	967	653
Total operating costs and expenses	442,811	248,438	348,175	232,882	83,407
Operating income (loss)	(442,811)	(248,438)	(348,175)	(232,882)	(83,407)
Other income (expense):					
Gain (loss) on sale of assets	1,555	—	2,996	—	—
Interest income	6,087	5,958	6,043	5,041	4,194
Interest expense	(63,376)	(74,768)	(65,376)	(3,212)	—
Total other income (expense)	(55,734)	(68,810)	(56,337)	1,829	4,194
Net income (loss) from continuing operations before income tax	(498,545)	(317,248)	(404,512)	(231,053)	(79,213)
Income tax expense (benefit)(1)	—	—	—	—	—
Net income (loss) from continuing operations	$ (498,545)	$ (317,248)	$ (404,512)	$ (231,053)	$ (79,213)
Net income (loss) from discontinued operations, net of income tax	(195,881)	(193,515)	(184,512)	(51,946)	(54,424)
Net income (loss)	(694,426)	(510,763)	(589,024)	(282,999)	(133,637)
Basic and diluted income (loss) per share from continuing operations	$ (1.22)	$ (0.78)	$ (0.99)	$ (0.57)	$ (0.21)
Basic and diluted income (loss) per share from discontinued operations	$ (0.48)	$ (0.47)	$ (0.46)	$ (0.13)	$ (0.14)
Basic and diluted income (loss) per share	$ (1.70)	$ (1.25)	$ (1.45)	$ (0.70)	$ (0.35)
Basic and diluted weighted average common shares outstanding	408,535,122	407,116,144	406,839,997	403,356,174	376,603,520

(1) No income tax benefit has been reflected since a full valuation allowance has been established against the deferred tax asset that would have been generated as a result of the operating results.

Consolidated Balance Sheet Information:

	As of December 31,				
	2015	2014	2013	2012	2011
			($ in thousands)		
Cash and cash equivalents(1)	$ 71,593	$ 246,704	$ 165,663	$ 1,376,437	$ 291,490
Restricted cash and cash equivalents	252,950	—	—	—	—
Short-term investments(2)	885,994	1,530,206	1,319,380	789,668	858,293
Total current assets(3)	3,146,291	2,003,134	1,967,443	2,456,742	1,335,094
Total property, plant and equipment(4)	895,936	714,654	567,914	499,762	432,694
Long-term restricted funds	—	—	—	720	718
Long-term investments	—	326,047	14,661	36,267	47,232
Total assets	4,094,103	4,450,862	3,633,673	4,011,459	2,527,944
Total current liabilities(5)	628,018	303,600	340,967	160,956	238,069
Total long term liabilities(6)	2,019,948	2,032,996	1,163,560	1,161,285	210,961
Total stockholders' equity	1,446,137	2,114,266	2,129,146	2,689,218	2,078,914
Total liabilities and stockholders' equity	4,094,103	4,450,862	3,633,673	4,011,459	2,527,944

(1) The decrease in cash and cash equivalents from December 31, 2012 to December 31, 2013 was primarily due to the investment in held-to-maturity securities from the proceeds we received upon the issuance of our 2.625% convertible senior notes due 2019 in December 2012.

(2) The decrease in short-term investment from December 31, 2014 to 2015 is due to maturities of securities. The increase in short-term investments from December 31, 2013 to December 31, 2014 was attributable to the investment of the proceeds from the issuance of our 3.125% convertible senior notes due 2024 in May 2014. The increase in short-term investments from December 31, 2012 to December 31, 2013 was attributable to the investment of the proceeds from the issuance of our 2.625% convertible senior notes due 2019 in December 2012.

(3) The increase from December 31, 2014 to December 31, 2015 was due to the Angolan entities being classified as held for sale and all assets associated with those entities being reflected as current.

(4) The increase from December 31, 2014 to December 31, 2015 reflects the capitalized costs for the Shenandoah #3 appraisal well, Shenandoah #3 appraisal well by-pass, Shenandoah #4 appraisal well, the initial Anchor appraisal well and bypass operation and North Platte #3 appraisal well and the Heidelberg development project, offset by impairments and dry hole expense of $309.0 million in 2015.The increase from December 31, 2013 to December 31, 2014 reflects the capitalized costs for the Anchor #1 exploration well, and the Heidelberg development costs. The increase from December 31, 2012 to December 31, 2013 primarily reflects the capitalized costs for the Diaman #1B exploration well. The increase from December 31, 2011 to 2012 reflects acquisition of unproved leases in the U.S. Gulf of Mexico and the capitalized costs for the Heidelberg #3 appraisal well and the North Platte #1 exploration well.

(5) The increase in current liabilities at December 31, 2015 was due to the Angolan entities being classified as held for sale and all liabilities associated with those entities being reflected as current. The increase in current liabilities at December 31, 2013 was due to year-end accruals for exploration costs primarily in West Africa and the short-term portion of the social and bonus payment obligations for Blocks 9, 20 and 21. The decrease in current liabilities at December 31, 2012 was primarily attributed to the payment of certain bonus obligations for Block 20 during 2012.

(6) The significant increase in long-term liabilities from December 31, 2013 to December 31, 2014 reflects the issuance of $1.3 billion aggregate principal amount of the 3.125% convertible senior notes due 2024 on May 13, 2014. The significant increase in long-term liabilities from December 31, 2011 to December 31, 2012 reflects the issuance of $1.38 billion aggregate principal amount of the 2.625% convertible senior notes due 2019 on December 17, 2012.

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

The following discussion contains forward-looking statements that involve risks and uncertainties. Our actual results may differ materially from those discussed in the forward-looking statements as a result of various factors, including, without limitation, those set forth in "Risk Factors," "Cautionary Note Regarding Forward-Looking Statements," and the other matters set forth in this Annual Report on Form 10-K. The following discussion of our financial condition and results of operations should be read in conjunction with our financial statements and the notes thereto included elsewhere in this Annual Report on Form 10-K, as well as the information presented under "Selected Financial Data." Due to the fact that we have not generated any revenue as of December 31, 2015, we believe that the financial information contained in this Annual Report on Form 10-K is not indicative of, or *comparable to, the financial profile that we expect to have for future periods. Except to the extent required by law, we undertake no obligation to update publicly any forward-looking statements for any reason, even if new information becomes available or other events occur in the future.*

OVERVIEW

We are an independent exploration and production company with operations currently focused in the deepwater U.S. Gulf of Mexico. In January 2016, we achieved initial production of oil and gas from the Heidelberg field. Our exploration efforts in the U.S. Gulf of Mexico have resulted in four oil and gas discoveries including the North Platte, Shenandoah, Anchor, and Heidelberg fields, each of which are in various stages of appraisal and development. We also have a non-operated interest in the Diaba Block offshore Gabon.

In August 2015, we executed a purchase and sale agreement with Sociedade Nacional de Combustíveis de Angola—Empresa Pública ("Sonangol") for the sale of our working interests in Blocks 20 and 21 offshore Angola for aggregate gross consideration of $1.75 billion before certain transaction expenses and other U.S. and Angolan taxes. The completion of this transaction is pending the receipt of Angola government approvals. We are continuing to work with Sonangol regarding the closing of the transaction, but we cannot make any assurances regarding the timing or occurrence of closing. Please see "Business—West Africa—Angola Transaction" for further information.

Our operational focus is to progress our North Platte, Shenandoah and Anchor discoveries toward project sanction; continue development drilling activities on the Heidelberg field with the aim to increase its oil and gas production over time; and selectively conduct exploration drilling on our current U.S. Gulf of Mexico acreage. We are also seeking to renew our world-wide exploration portfolio by pursuing new acreage opportunities in the U.S. Gulf of Mexico and evaluating certain other new venture opportunities. In light of the current market environment and significant downturn in oil and gas prices, we are continuing our efforts to reduce our cost structure company-wide which includes reducing or deferring certain activities.

Factors Affecting Comparability of Future Results

You should read this management's discussion and analysis of our financial condition and results of operations in conjunction with our historical financial statements included elsewhere in this Annual Report on Form 10-K. Below are the period-to-period comparisons of our historical results and the analysis of our financial condition. In addition to the impact of the matters discussed in "Risk Factors," our future results could differ materially from our historical results due to a variety of factors, including the following:

Discontinued Operations. Our historical financial statements included in this Annual Report on Form 10-K reflect our assets in Angola being held for sale pending the completion of the Angola Transaction. Certain prior year amounts have been reclassified for consistency with the current period presentation due to the Angola Transaction meeting the criteria to be reported in discontinued operations as of December 31, 2015. In addition, if such transaction is consummated, our future performance without the effect of owning such Angolan assets may materially differ from that reflected in our historical financial statements.

See "Risk Factors— Risks Relating to Our Business—The sale of our interests in Blocks 20 and 21 offshore Angola is subject to Angolan government approval, and such sale may be delayed or may not be consummated. In addition, pursuant to the terms of the purchase and sale agreement governing such sale, we are obligated to transfer our interests in Block 20 and 21 prior to receipt of all consideration for such transfer."

Oil and gas revenue. We did not produce any revenue during the year ended December 31, 2015, although we achieved initial production from the Heidelberg field in the U.S. Gulf of Mexico in January 2016. Initial production at Heidelberg was achieved with two of the first three planned development wells tied back to a moored production handling SPAR. The other completed development well is expected to begin production in the near future resulting in an initial total of three producing wells. Two additional development wells are expected to be drilled, completed and brought onto production at Heidelberg within the next year. Because we have not historically produced any oil or gas, our future results of operations will differ materially from our historical results of operations due to the generation of revenue from the sale of oil and gas. As a result of our initial production of oil and gas in January 2016, our business and the revenue we may generate from such production will become more susceptible to fluctuations in oil and gas prices. Continuation of the substantial and extended decline in oil and natural gas prices may materially and adversely affect our future business, financial condition, and the market price of our common stock, results of operations, liquidity or ability to finance planned capital expenditures.

Our ability to discover and develop oil and gas reserves Our future results of operations and financial condition will be directly affected by our ability to discover and develop reserves through our exploration, appraisal and development drilling activities, specifically our ability to sanction our North Platte, Shenandoah and Anchor projects for development. The calculation of our geological and petrophysical estimates is complex and imprecise, and it is possible that our future exploration will not result in additional discoveries, and, even if we are able to successfully make such discoveries, there is no certainty that the discoveries will be commercially viable to produce. Our results of operations will be adversely affected in the event that our estimated oil and gas asset base does not result in reserves that may eventually be commercially developed.

Production Costs. We have only recently commenced production activities and started to incur production costs. Production costs are the costs incurred in the operation of producing and processing our production and are primarily comprised of lease operating expense, workover costs and production and ad valorem taxes. No production costs are reflected in our historical financial statements.

General and Administrative Expenses. These costs include expenses associated with our staff costs, information technology, rent, travel, annual and quarterly reporting, investor relations, registrar and transfer agent fees, incremental insurance costs, and accounting and legal services. In light of the current market environment and significant downturn in oil and gas prices, we are continuing our efforts to reduce our cost structure company-wide which includes reducing or deferring certain activities. On February 19, 2016, the Company initiated a workforce reduction program. We estimate that this program will result in cash expenditures between $10 million to $15 million relating to severance payments. Actual expenditures will vary if planned reductions do not occur as expected. See Note 22 “Subsequent Events” to our consolidated financial statement for the year ended December 31, 2015 included elsewhere in this Annual Report on Form 10-K.

Depreciation, Depletion and Amortization. We have only recently commenced production activities. In future periods, we will amortize the costs of successful exploration, appraisal, drilling and field development using the unit-of-production method based on total estimated proved developed oil and gas reserves. Costs of acquiring proved and unproved leasehold properties and associated asset retirement costs will be amortized using the unit-of-production method based on total estimated proved developed and undeveloped reserves. No depletion of oil and gas properties is reflected in our historical financial statements.

Demand and Price. The demand for oil and gas is susceptible to volatility related to, among other factors, policy decisions by oil-producing nations, the level of global economic activity and may also fluctuate depending on the performance of specific industries. We expect that a decrease in economic activity, in the United States and elsewhere, would adversely affect demand for oil and gas we expect to produce. Since we have not generated revenues, these key factors will only affect our financial statements when we produce and sell hydrocarbons.

Results of Operations

We operate our business in the U.S. Gulf of Mexico and Gabon, West Africa. The discussion of the results of operations and the period-to-period comparisons presented below for consolidated operations analyzes our historical results. The following discussion may not be indicative of future results.

Fiscal year ended December 31, 2015 as compared to year ended December 31, 2014

	Year Ended December 31, 2015	Year Ended December 31, 2014	Increase (Decrease)	Percentage Change
	($ in thousands)			
Consolidated Operations:				
Oil and gas revenue	**$ —**	**$ —**	**$ —**	**—%**
Operating costs and expenses				
Seismic and exploration	45,318	41,431	3,887	9%
Dry hole expense and impairment	308,960	133,223	175,737	132%
General and administrative	87,031	72,090	14,941	21%
Accretion expense	99	—	99	100%
Depreciation and amortization	1,403	1,694	(291)	(17)%
Total operating costs and expenses	**442,811**	**248,438**	**194,373**	**78%**
Operating income (loss)	**(442,811)**	**(248,438)**	**(194,373)**	**78%**
Other income (expense)				
Gain (loss) on sale of assets	1,555	—	1,555	100%
Interest income	6,087	5,958	129	2%
Interest expense	(63,376)	(74,768)	11,392	(15)%
Total other income (expense)	**(55,734)**	**(68,810)**	**13,076**	**(19)%**
Net income (loss) from continuing operations before income tax	**(498,545)**	**(317,248)**	**(181,297)**	**57%**
Income tax expense (benefit)	—	—	—	—
Net income (loss) from continuing operations	**$ (498,545)**	**$ (317,248)**	**$ (181,297)**	**57%**

Consolidated Operations

Oil and gas revenue. We did not realize any oil and gas revenue during the years ended December 31, 2015 and 2014, respectively.

Operating costs and expenses. Our operating costs and expenses for our operations consisted of the following during the years ended December 31, 2015 and 2014:

Seismic and exploration. Seismic and exploration costs increased by approximately $3.9 million during the year ended December 31, 2015, as compared to the year ended December 31, 2014. The increase was primarily due to a $3.8 million increase in seismic costs and a $0.6 million increase in exploration expenses offset by the decrease of $0.5 million in delay rental.

Dry hole expense and impairment. Dry hole expense and impairment increased by $175.7 million during the year ended December 31, 2015, as compared to the year ended December 31, 2014. The increase is due to impairment of proved property and unproved leasehold properties and dry hole expense written off against exploration wells as reflected in the following table:

	Year Ended December 31,		
	2015	**2014**	**Increase (Decrease)**
		($ in thousands)	
Impairment of Unproved leasehold:			
Other leasehold(1)	$ 15,494	$ 57,308	$ (41,814)
Amortization of leasehold with carrying value under $1 million	11,403	10,662	741
Impairment of Proved property:			
Heidelberg	256,779	—	256,779
Dry Hole Expense:			
Ligurian #1 exploration well	(2)	46	(48)
Ligurian #2 exploration well	203	—	203
Ardennes #1 exploration well	347	(133)	480
Aegean #1 exploration well	668	3,920	(3,252)
Anchor #1 exploration well	(2,043)	38,075	(40,118)
Yucatan #2 exploration well	(203)	17,313	(17,516)
Shenandoah by-pass #3 appraisal well	147	5,032	(4,885)
North Platte #2 appraisal well	18,358	—	18,358
Shenandoah VSP	248	—	248
Shenandoah #4 appraisal well	6,564	—	6,564
Criollo exploration well	(18)	—	(18)
Other Impairments:			
Obsolete inventory	1,015	1,000	15
	$ 308,960	$ 133,223	$ 175,737

(1) Other leasehold includes certain unproved oil and gas leases for properties in the U.S. Gulf of Mexico with carrying value greater than $1 million that we have no exploration activity planned, based on our three-year exploration plan, during the remaining term of the leases.

General and administrative. General and administrative costs increased by $14.9 million during the year ended December 31, 2015 as compared to the year ended December 31, 2014. The increase in general and administrative costs during this period was primarily attributed to a $4.3 million increase in staff related expenses which includes non-cash equity compensation, an increase of $3.4 million in legal and consulting fees and a decrease of $9.2 million in recoveries from partners associated with drilling activities offset by a $2.0 million decrease in insurance and office support costs.

Depreciation and amortization. Depreciation and amortization did not materially change during the year ended December 31, 2015 as compared to the year ended December 31, 2014.

Other income (expense). Other income (expense) decreased by $13.1 million for the year ended December 31, 2015 as compared to the year ended December 31, 2014. The decrease was primarily due to a $16.8 million increase in interest expense associated with the issuance of the 3.125% convertible senior notes due 2024 on May 13, 2014, a $19.1 increase in amortization of debt issuance costs and accretion of discount, offset by an increase in capitalized interest of $47.4 million due to increased project activity and a $1.6 million increase in other income attributed to gain on sale of other assets during the year ended December 31, 2015.

Income taxes. As a result of net operating losses, for income tax purposes, we recorded a net deferred tax asset of $896.3 million and $568.0 million with a corresponding full valuation of $896.3 million and $568.0 million for the years ended December 31, 2015 and 2014, respectively.

Fiscal year ended December 31, 2014 as compared to year ended December 31, 2013

	Year Ended December 31, 2014	Year Ended December 31, 2013	Increase (Decrease)	Percentage Change
	($ in thousands)			
Consolidated Operations:				
Oil and gas revenue	**$ —**	**$ —**	**$ —**	**—%**
Operating costs and expenses				
Seismic and exploration	41,431	49,847	(8,416)	(17)%
Dry hole expense and impairment	133,223	224,105	(90,882)	(41)%
General and administrative	72,090	72,895	(805)	(1)%
Depreciation and amortization	1,694	1,328	366	28%
Total operating costs and expenses	**248,438**	**348,175**	**(99,737)**	**(29)%**
Operating income (loss)	**(248,438)**	**(348,175)**	**99,737**	**(29)%**
Other income (expense)				
Gain (loss) on sale of assets	—	2,996	(2,996)	(100)%
Interest income	5,958	6,043	(85)	(1)%
Interest expense	(74,768)	(65,376)	(9,392)	14%
Total other income (expense)	**(68,810)**	**(56,337)**	**(12,473)**	**22%**
Net income (loss) from continuing operations before income tax	**(317,248)**	**(404,512)**	**87,264**	**(22)%**
Income tax expense (benefit)	—	—	—	—
Net income (loss) from continuing operations	**$ (317,248)**	**$ (404,512)**	**$ 87,264**	**(22)%**

Consolidated Operations:

Oil and gas revenue. We did not realize any oil and gas revenue during the years ended December 31, 2014 and 2013.

Operating costs and expenses. Our operating costs and expenses for our consolidated operations consisted of the following during the years ended December 31, 2014 and 2013:

Seismic and exploration. Seismic and exploration costs decreased by approximately $8.4 million during the year ended December 31, 2014, as compared to the year ended December 31, 2013. The decrease was primarily due to an $11.8 million decrease in seismic costs offset by the increase of $0.7 million in delay rental and $2.7 million in exploration expenses attributed primarily to standby costs on the Ensco 8503 incurred during January 2014.

Dry hole expense and impairment. Dry hole expense and impairment decreased by $90.9 million during the year ended December 31, 2014, as compared to the year ended December 31, 2013. The decrease is due to impairment of unproved leasehold properties and dry hole expense written off against exploration wells as reflected in the following table:

	Year Ended December 31,		
	2014	2013	Increase (Decrease)
		($ in thousands)	
Impairment of Unproved leasehold:			
Ardennes prospect	$ —	$ 29,122	$ (29,122)
Aegean prospect	—	38,499	(38,499)
Other leasehold(1)	57,308	10,002	47,306
Amortization of leasehold with carrying value under $1 million	10,662	9,417	1,245
Dry Hole Expense:			
Ligurian #1 exploration well	46	631	(585)
Ardennes #1 exploration well	(133)	66,133	(66,266)
Aegean #1 exploration well	3,920	53,235	(49,315)
Anchor #1 exploration well	38,075	—	38,075
Yucatan #2 exploration well	17,313	—	17,313
Shenandoah by-pass #3 appraisal well	5,032	—	5,032
Diaman #1 exploration well	—	17,066	(17,066)
Other Impairments:			
Obsolete inventory	1,000	—	1,000
	$ 133,223	$ 224,105	$ (90,882)

(1) Other leasehold includes certain unproved oil and gas leases for properties in the U.S. Gulf of Mexico with carrying value greater than $1 million that we have no exploration activity planned, based on our three-year exploration plan, during the remaining term of the leases.

General and administrative. General and administrative costs decreased by $0.8 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013. The decrease in general and administrative costs during this period was primarily attributed to a $10.2 million increase in staff related expenses which includes non-cash equity compensation and a $3.0 million increase in insurance and office support costs, offset by a decrease of $3.7 million in legal and consulting fees and an increase of $10.5 million in recoveries from partners associated with drilling activities.

Depreciation and amortization. Depreciation and amortization did not change significantly during the year ended December 31, 2014 as compared to the year ended December 31, 2013.

Other income (expense). Other income (expense) increased by $12.5 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase was primarily due to a $9.4 million increase in interest expense associated with the issuance of the 3.125% convertible senior notes due 2024 on May 13, 2014 and a $3.0 million decrease in other income attributed to gain on sale of other assets during the year ended December 31, 2013.

Income taxes. As a result of net operating losses, for income tax purposes, we recorded a net deferred tax asset of $568.0 million and $461.6 million with a corresponding full valuation of $568.0 million and $461.6 million for the years ended December 31, 2014 and 2013, respectively.

Liquidity and Capital Resources

As of December 31, 2015, we had approximately $1.2 billion in cash, which includes cash and cash equivalents, investments, and restricted cash, but excludes cash and restricted cash held within assets held for sale. This amount of $1.2 billion includes the $250 million we received from Sonangol pursuant to the Purchase and Sale Agreement, which is classified as restricted cash pending the closing of the Angola Transaction. We expect to expend approximately $450 to $500 million for our U.S. Gulf of Mexico capital expenditures in 2016, which excludes general and administrative and interest expense. In addition, we expect to spend approximately $110 million on a net basis for operations on Blocks 20 and 21 Angola pending the closing of the Angola Transaction. Pursuant to the terms of the Purchase and Sale Agreement governing the Angola Transaction, we are entitled to reimbursement of such amounts upon the closing of the Angola Transaction. We expect that our existing cash on hand plus proceeds from the closing of the Angola Transaction will be sufficient to fund our current operations for the foreseeable future.

On May 29, 2015, Cobalt GOM #1 LLC, our indirect, wholly-owned subsidiary, entered into a Borrowing Base Facility Agreement (the “Facility Agreement”) with Société Générale, as administrative agent, and certain other lenders. The Facility Agreement provides for a limited recourse senior secured reserve-based term loan facility with a current borrowing base of $150 million. We have not borrowed any amounts under the Facility Agreement. We expect the next redetermination of the borrowing base for this loan facility will occur in March 2016. Please see “Item 1A. Risk Factors—The borrowing base under our Heidelberg reserve-based loan facility will likely be substantially reduced in the near future, which could negatively impact our funding for future development drilling at Heidelberg.”

For the year ended December 31, 2015, we did not generate any revenue from oil and gas production, although we commenced initial production from our Heidelberg project in January 2016. Until substantial production is achieved, our primary sources of liquidity are expected to be cash on hand, the proceeds from the closing of the Angola Transaction, funds available to us under the Facility Agreement, proceeds from any future reserve-based lending arrangements, equity and debt financings, and asset-based ventures and asset monetizations.

We expect to incur substantial expenditures and generate significant operating losses as we:

- progress our North Platte, Shenandoah and Anchor discoveries toward project sanction;
- continue development drilling activities on the Heidelberg field with the aim to increase its oil and gas production over time;
- selectively conduct exploration drilling on our current U.S. Gulf of Mexico acreage;
- pursue new acreage opportunities in the U.S. Gulf of Mexico; and
- incur expenses related to operating as a public company and compliance with regulatory requirements.

Our future financial condition and liquidity will be impacted by, among other factors, the timing or occurrence of the closing of the Angola Transaction, the production rates achieved from our Heidelberg project, our ability to obtain financing or refinance existing indebtedness, oil and gas prices, the number of commercially viable hydrocarbon discoveries made and the quantities of hydrocarbons discovered, the speed with which we can bring such discoveries to production, whether and to what extent we invest in additional oil leases and concessional licenses, and the actual cost of exploration, appraisal and development of our prospects. We may also seek additional funding through equity and debt financings. Additional funding may not be available to us on acceptable terms or at all. In addition, the terms of any financing may adversely affect the holdings or the rights of our existing stockholders. For example, if we raise additional funds by issuing additional equity securities, further dilution to our existing stockholders will result. Funds available to us under existing or future reserve-based lending arrangements, including the Facility Agreement, may decrease in connection with periodic redeterminations of the value of the oil and gas reserves pledged pursuant to such lending arrangements. If we are unable to obtain or maintain funding on a timely basis or on acceptable terms, we may be required to significantly curtail our exploration, appraisal and development activities. Please see “Item 1A. Risk Factors—Our business plan requires substantial additional capital, which we may be unable to raise on acceptable terms in the future, which may in turn limit our ability to execute our development projects and achieve production, conduct exploration activities or renew our exploration portfolio.”

Royalty Agreement

On February 13, 2009 we entered into a restated overriding royalty agreement (the “Royalty Agreement”) with Whitton Petroleum Services Limited (“Whitton”). Pursuant to the terms of the Royalty Agreement, in consideration for Whitton’s consulting services in connection with Blocks 9, 20 and 21 offshore Angola and our business and operations in Angola, Whitton is to receive quarterly payments (measured in U.S. Dollars) equal to 2.5% of the market price of our share of the crude oil produced in such quarter and not used in petroleum operations, less the cost recovery crude oil, assuming the applicable government contract is a production sharing agreement. If the applicable government contract is a risk services agreement and not a production sharing agreement (which is the case with respect to Blocks 9 and 21), pursuant to the Royalty Agreement we have undertaken to agree with Whitton an economic model (the “RSA Economic Model”) containing terms equivalent to those in such risk services agreement and using actual production and costs. The RSA Economic Model has not yet been agreed with Whitton. If we assign all of our interests in such Blocks, Whitton may, depending on the option we elect, have the right to receive the market value of its rights and obligations under the Royalty Agreement, based upon the amount in cash a willing transferee of such rights and obligations would pay a willing transferor in an arm’s length transaction. Given potential issues regarding how such market value of Whitton’s rights and obligations under the Royalty Agreement could be calculated, including, without limitation, outstanding issues related to the RSA Economic Model, the amount of any such payment that could be owed to Whitton upon consummation of the Angola Transaction is uncertain, but may be significant. Resolution of any such payment may include an expert determination of such cash value payment. We can make no assurance that any results from an expert determination process will be favorable to us. Please see "Item 1A. Risk Factors—We may be required to pay a material cash sum to Whitton Petroleum Services Limited ("Whitton") in connection with the closing of the sale of our interests in Blocks 20 and 21 offshore Angola."

Cash Flows from continuing operations

	Year Ended December 31.		
	2015	2014	2013
		($ in thousands)	
Net cash provided by (used in):			
Operating Activities	$ (135,424)	$ 9,986	$ (139,922)
Investing Activities	496,572	(779,375)	(807,690)
Financing Activities	(4,068)	1,269,180	(992)

Operating activities. Net cash of $135.4 million used in operating activities during 2015, $10.0 million provided by operating activities during 2014 and $139.9 million used in operating activities during 2013 were primarily related to cash payments for seismic expenses, exploration expenses and inventory.

Investing activities. Net cash provided by investing activities in 2015 was approximately $496.6 million, compared with net cash used in investing activities of approximately $779.4 million and $807.7 million in 2014 and 2013, respectively. The net cash provided in 2015 primarily relates to capital expenditures incurred for the Shenandoah #3 appraisal well, Shenandoah #3 appraisal well by-pass, Shenandoah #4 appraisal well, initial Anchor appraisal well and bypass operation and North Platte #3 appraisal well and the Heidelberg development project in the deepwater U.S. Gulf of Mexico, and maturities of investments of $1.9 billion. The net cash used in 2014 primarily relates to capital expenditures incurred for the Shenandoah #3 appraisal well, Shenandoah #3 appraisal well by-pass, Anchor #1, Anchor #2 and Yucatan #2 exploration wells and the Heidelberg development project in the deepwater U.S. Gulf of Mexico, and purchase of investment securities from the net proceeds of the 3.125% convertible senior notes due 2024. The net cash used in 2013 primarily relates to capital expenditures relating to the Ardennes #1 and Aegean #1 exploration wells in the deepwater U.S. Gulf of Mexico and the Diaman #1B exploration well offshore Gabon.

Financing activities. Net cash used in financing activities in 2015 was approximately $4.1 million, compared with net cash provided by financing activities in 2014 of approximately $1.3 billion and net cash used in financing activities of approximately $1.0 million in 2013. The $4.1 million net cash used in financing activities relates to the debt issuance costs paid during 2015. The $1.3 billion in net cash provided by financing activities in 2014 relates to net proceeds we received from the issuance of our 3.125% convertible senior notes due 2024 in May 2014. The $1.0 million net cash used in financing activities relates to the debt issuance costs paid during 2013.

Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of December 31, 2015:

	Payments Due By Year						
	2016	2017	2018	2019	2020	Thereafter	Total
				($ in thousands)			
Drilling Rig and Related Contracts; midstream agreements	$245,726	$246,464	$ 26,236	$ 7,175	$ 5,907	$ 10,133	$ 541,641
Operating Leases	2,263	2,309	2,369	2,405	2,454	3,172	14,972
Lease Rentals(1)	5,578	5,220	2,839	2,446	2,341	7,182	25,606
Long-term Debt Obligations(2):							—
Principal	—	—	—	1,380,000	—	1,300,000	2,680,000
Interest	76,850	76,850	76,850	76,850	40,625	131,241	479,266
Total	**$330,417**	**$330,843**	**$108,294**	**$1,468,876**	**$ 51,327**	**$1,451,728**	**$3,741,485**

(1) Relates to the annual delay rental payments payable to the Office of Natural Resources Revenue within the U.S. Department of the Interior with respect to our U.S. Gulf of Mexico leases. These annual payments are required to maintain the leases from year to year.

(2) Represents principal amounts of our 2.625% convertible senior notes due 2019 and our 3.125% convertible senior notes due 2024 and interest payable semi-annually in arrears.

In the future, we may be party to additional contractual arrangements including but not limited to arrangements listed below, which will subject us to further contractual obligations:

- credit facilities and other debt instruments;
- contracts for the lease of additional drilling rigs;
- contracts for the provision of production facilities;
- infrastructure construction contracts; and
- long term oil and gas property lease arrangements.

Off-Balance Sheet Arrangements

As of December 31, 2015, we did not have any off-balance sheet arrangements.

Critical Accounting Policies

This discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements, which have been prepared in accordance with generally accepted accounting principles in the United States. The preparation of our financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates. Our significant accounting policies are detailed in Note 1 to our consolidated financial statements. We have outlined below certain accounting policies that are of particular importance to the presentation of our financial position and results of operations and require the application of significant judgment or estimates by our management.

Revenue Recognition. We plan to follow the "sales" (or cash) method of accounting for oil and gas revenues. Under this method, we will recognize revenues on the volumes sold. The volumes sold may be more or less than the volumes to which we are entitled based on our ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. For the year ended December 31, 2015, no revenues have been recognized in our financial statements.

We recognize interest income on bank balances and deposits on a time basis, by reference to the principal outstanding and at the effective interest rate applicable.

Cash and Cash Equivalents. Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less from the date of purchase. Demand deposits typically exceed federally insured limits; however we periodically assess the financial condition of the institutions where these funds are held as well as the credit ratings of the issuers of the highly liquid instruments and believe that the credit risk is minimal.

Investments. Our investments consist entirely of debt securities. The debt securities are carried at amortized costs and classified as held-to-maturity as we have the positive intent and ability to hold them until they mature. The net carrying value of held-to-maturity securities is adjusted for amortization of premiums and accretion of discounts to maturity over the life of the securities. Money market funds and certificates of deposit are carried at face value.

We conduct a regular assessment of our debt securities with unrealized losses to determine whether securities have other-than-temporary impairment. This assessment considers, among other factors, the nature of the securities, credit rating or financial condition of the issuer, the extent and duration of the unrealized loss, market conditions and whether we intend to sell or whether it is more likely than not that we will be required to sell the debt securities.

Property, Plant and Equipment. We use the "successful efforts" method of accounting for our oil and gas properties. Acquisition costs for unproved leasehold properties and costs of drilling exploration wells are capitalized pending determination of whether proved reserves can be attributed to the areas as a result of drilling those wells. Under the successful efforts method of accounting, proved leasehold costs are capitalized and amortized over the proved developed and undeveloped reserves on a units-of-production basis. Successful drilling costs, costs of development and developmental dry holes are capitalized and amortized over the proved developed reserves on a units-of-production basis. When circumstances indicate that proved oil and gas properties may be impaired, we compare expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the unamortized capitalized cost of the asset. If the expected undiscounted future cash flows, based on our estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach described in the Fair Value Measurement Topic of the ASC. Significant unproved leasehold costs are capitalized and are not amortized, pending an evaluation of their exploration potential. Unproved leasehold costs are assessed on an individual basis periodically to determine if an impairment of the cost of individual properties has occurred. Factors taken into account for impairment analysis include results of the technical studies conducted, lease terms and management's future exploration plans. The cost of impairment is charged to expense in the period in which it occurs. Costs incurred for exploration dry holes, geological, and geophysical work (including the cost of seismic data), and delay rentals are charged to expense as incurred. Costs of other property and equipment are depreciated on a straight-line basis based on their respective useful lives.

Inventory. Inventories consist of various tubular products that will be used in our drilling programs. The inventory is stated at the average cost. Cost is determined using a weighted average method comprised of the purchase price and other directly attributable costs.

Income Taxes. We apply the liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are determined by applying tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the financial statements. Since we are in development stage and there can be no assurance that we will generate any earnings or any specific level of earnings in future years, we establish a valuation allowance for deferred tax assets (net of liabilities).

Use of Estimates. The preparation of our consolidated financial statements in conformity with United States Generally Accepted Accounting Principles requires us to make estimates and assumptions that impact our reported assets and liabilities, disclosure of contingent assets and liabilities at the date of our consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include: (i) accruals related to expenses, (ii) assumptions used in estimating fair value of equity-based awards and the fair value of the liability component of the convertible senior notes and (iii) assumptions used in impairment testing. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Estimates of Proved Oil & Natural Gas Reserves. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and impairment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. As of December 31, 2015, we have proved undeveloped reserves in the U.S. Gulf of Mexico. Estimated reserve quantities and future cash flows were estimated by independent petroleum consultants and prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board. The accuracy of these reserve estimates is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future operating cost, severance taxes, development cost and workover cost, all of which may in fact vary considerably from actual results;
- the accuracy of various mandated economic assumptions (such as the future prices of oil and natural gas); and
- the judgments of the persons preparing the estimates.

Asset Retirement Obligations. The Company expects to have significant obligations under its lease agreements and federal regulation to remove its equipment and restore land or seabed at the end of oil and natural gas production operations. These asset retirement obligations ("ARO") are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and natural gas platforms. Estimating the future restoration and removal cost is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulation often have vague descriptions of what constitutes removal. Asset removal technologies and cost are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. We record a separate liability for the discounted present value of our asset retirement obligations, with an offsetting increase to the related oil and natural gas properties. The cost of the related oil and natural gas asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at our credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Inherent to the present value calculation are numerous estimates, assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted risk-free rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the abandonment liability, we will make corresponding adjustments to both the asset retirement obligation and the related oil and natural gas property asset balance. Increases in the discounted abandonment liability resulting from the passage of time will be reflected as additional accretion in the consolidated statement of operations.

Earnings (Loss) Per Share. Basic earnings (loss) per share was calculated by dividing net income or loss applicable to common shares by the weighted average number of common shares outstanding during the periods presented. Diluted earnings (loss) per share incorporate the potential dilutive impact of our 2.625% convertible senior notes due 2019, our 3.125% convertible senior notes due 2024, stock options, unvested restricted stock and restricted stock units outstanding during the periods presented, unless their effect is anti-dilutive. In addition, we apply the if-converted method to our convertible debt instruments, the effect of which is that conversion will not be assumed for purposes of computing diluted earnings (loss) per share if the effect would be anti-dilutive.

Equity-Based Compensation. We account for stock-based compensation at fair value. We grant various types of stock-based awards including stock options, restricted stock and performance-based awards. The fair value of stock option awards is determined by using the Black-Scholes-Merton option-pricing model. For restricted stock awards with market conditions, the fair value of the awards is measured using the asset-or-nothing option pricing model. Restricted stock awards without market conditions and the performance-based awards are valued using the market price of our common stock on the grant date. We record compensation cost, net of estimated forfeitures, on a straight-line basis for stock-based compensation awards over the requisite service period except for performance-based awards. For performance-based awards, compensation cost is recognized over the requisite service period as and when we determine that the achievement of the performance condition is probable, using the per-share fair value measured at grant date.

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 risks” refers to the risk of loss arising from changes in commodity prices, interest rates, foreign currency exchange rates, and other relevant market risks. 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 and manage our ongoing market risk exposures. All of our market risk sensitive instruments will be entered into for purposes of risk management and not for speculation.

Due to the historical volatility of commodity prices, we may enter into various derivative instruments to manage our exposure to volatility of commodity market prices. We may use options (including floors and collars) and fixed price swaps to mitigate the impact of downward swings in commodity prices to our cash flow. All contracts will be settled with cash and would not require the delivery of physical volumes to satisfy settlement. While in times of higher commodity prices this strategy may result in our having lower net cash inflows than we would otherwise have if we had not utilized these instruments, management believes the risk reduction benefits of such a strategy would outweigh the potential costs.

We may borrow under fixed rate and variable rate debt instruments that give rise to interest rate risk. Our objective in borrowing under fixed or variable rate debt is to satisfy capital requirements while minimizing our costs of capital.

Item 8. *Financial Statements and Supplementary Data*

The information required is included in this report as set forth in the “Index to Consolidated Financial Statements” on page F-1 to this Annual Report on Form 10-K.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None

Item 9A. *Controls and Procedures*

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2015, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer ("CEO") and our Chief Financial Officer ("CFO"), as to the effectiveness, design and operation of our disclosure controls and procedures. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the U.S. Securities and Exchange Commission reports we file or submit under the Exchange Act is accurate, complete and timely. Our management, including our CEO and CFO, does not expect that our disclosure controls and procedures or our internal controls will prevent and/or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefit of controls must be considered relative to their costs. Because of the inherent limitation in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and our CEO and CFO concluded that our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective as of December 31, 2015.

Management's Report on Internal Control over Financial Reporting

The information required to be furnished pursuant to this item is set forth under the caption "Management's Report on Internal Control over Financial Reporting" in Item 8 of this Annual Report on Form 10-K.

Attestation Report of the Registered Public Accounting Firm

The information required to be furnished pursuant to this item is set forth under the caption "Report of Independent Registered Public Accounting Firm" in Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control Over Financial Reporting

There have been no other changes in our internal control over financial reporting during the fourth quarter ended December 31, 2015, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. *Other Information*

On February 18, 2016, the Board of Directors (the "Board") of Cobalt International Energy, Inc. (the "Company") elected Mr. John E. Hagale as a member of the Board, effective as of March 1, 2016. Mr. Hagale will serve as a Class III director and his initial term will expire at the Company's 2018 Annual Meeting of Stockholders. In addition, Mr. Hagale has been appointed as a member of the Audit Committee of the Board. The Board has also made the affirmative determination that Mr. Hagale qualifies as an independent director under the Securities Exchange Act of 1934, as amended (the "Exchange Act") and the rules of the New York Stock Exchange. Pursuant to the terms of the Company's Non-Employee Directors Compensation Plan, for serving as a non-employee director, Mr. Hagale will receive a $100,000 annual retainer (prorated to $83,607 for calendar year 2016), an initial award of restricted stock units with a value of $44,110 for his service through May 31, 2016 and an annual award of restricted stock units with a value of $175,000 for each year of his service thereafter. The retainers will be payable at Mr. Hagale's election in cash and/or shares of the Company's common stock. Each award of restricted stock units will be granted pursuant to a Restricted Stock Unit Award Notification under the Company's Non-Employee Directors Compensation Plan and generally will be payable to Mr. Hagale one year after grant in shares of the Company's common stock. Payment with respect to the retainers and restricted stock units may be deferred at Mr. Hagale's election pursuant to the terms of the Company's Non-Employee Directors Deferral Plan.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

The information required by this item is set forth under the captions "Election of Directors," "Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our definitive Proxy Statement (the "2016 Proxy Statement") for our annual meeting of stockholders to be held on April 28, 2016, which sections are incorporated herein by reference.

Pursuant to Item 401(b) of Regulation S-K, the information required by this item with respect to our executive officers is set forth in Part I of this Annual Report on Form 10-K.

Item 11. *Executive Compensation*

The information required by this item is set forth in the sections entitled “Election of Directors—Director Compensation,” “Executive Compensation” and “Corporate Governance” in the 2016 Proxy Statement, which sections are incorporated herein by reference.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The information required by this item is set forth in the sections entitled “Security Ownership of Certain Beneficial Owners and Management” and “Executive Compensation—Equity Compensation Plan Information” in the 2016 Proxy Statement, which sections are incorporated herein by reference.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

The information required by this item is set forth in the section entitled “Corporate Governance” and “Certain Relationships and Related Transactions” in the 2016 Proxy Statement, which sections are incorporated herein by reference.

Item 14. *Principal Accounting Fees and Services*

The information required by this item is set forth in the section entitled “Ratification of Appointment of Independent Auditors” in the 2016 Proxy Statement, which section is incorporated herein by reference.

GLOSSARY OF SELECTED OIL AND GAS TERMS

“2-D seismic data”	Two-dimensional seismic data, being an interpretive data that allows a view of a vertical cross-section beneath a prospective area.
“3-D seismic data”	Three-dimensional seismic data, being geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D seismic data.
“Angola PAL”	Angola Petroleum Activities Law.
“Appraisal well”	A well drilled after an exploration well to gain more information on the drilled reservoirs.
“Barrel”	A standard measure of volume for petroleum corresponding to approximately 42 gallons at 60 degrees Fahrenheit.
“Bbl”	Barrel.
“Bcf”	Billion cubic feet.
“Below-salt”	A term encompassing both subsalt, as used in connection with the U.S. Gulf of Mexico, and pre-salt, as used in connection with offshore West Africa.
“Block 9 RSA”	Risk Service Agreement governing Block 9 offshore Angola.
“Block 21 RSA”	Risk Service Agreement governing Block 21 offshore Angola.
“Block 20 PSC”	Production Sharing Contract governing Block 20 offshore Angola.
“Blowouts”	Blowout is the uncontrolled release of a formation fluid, usually gas, from a well being drilled, typically for petroleum production.
“BOEPD”	Barrels of oil equivalent per day. Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency.
“BOPD”	Barrels of oil per day.
“Btu”	British thermal unit.
“Completion”	The procedure used in finishing and equipping an oil or natural gas well for production.

"Delay rental"	Payment made to the lessor under a non-producing oil and natural gas lease at the beginning or end of each year to continue the lease in force for another year during its primary term.
"Development"	The phase in which an oil field is brought into production by drilling development wells and installing appropriate production systems.
"Development well"	A well drilled to a known formation in a discovered field, usually offsetting a producing well on the same or an adjacent oil and natural gas lease.
"Drilling and completion costs"	All costs, excluding operating costs, of drilling, completing, testing, equipping and bringing a well into production or plugging and abandoning it, including all labor and other construction and installation costs incident thereto, location and surface damages, cementing, drilling mud and chemicals, drillstem tests and core analysis, engineering and well site geological expenses, electric logs, costs of plugging back, deepening, rework operations, repairing or performing remedial work of any type, costs of plugging and abandoning any well participated in by us, and reimbursements and compensation to well operators.
"Dry hole"	An exploration, appraisal or development well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
"DST"	Drill stem test
"E&P"	Exploration and production.
"EPSC"	Exploration and Production Sharing Contract.
"Exploration well"	A well drilled either (a) in search of a new and as yet undiscovered pool of oil or natural gas or (b) with the hope of significantly extending the limits of a pool already developed.
"Farm-out"	An agreement whereby the owner of the leasehold or working interest agrees to assign a portion of his interest in certain acreage subject to the drilling of one or more specific wells or other performance by the assignee as a condition of the assignment. Under a farm-out, the owner of the leasehold or working interest may retain some interest such as an overriding royalty interest, an oil and natural gas payment, offset acreage or other type of interest.
"Field"	A geographical area under which an oil or natural gas reservoir lies in commercial quantities.
"FERC"	Federal Energy Regulatory Commission
"FPSO"	Floating Production, Storage and Offloading system.
"Gathering system"	Pipelines and other facilities that transport oil from wells and bring it by separate and individual lines to a central delivery point for delivery into a transmission line or mainline.
"Gross acre"	An acre in which a working interest is owned. The number of gross acres is the total number of acres in which an interest is owned.
"Horizon"	A zone of a particular formation; that part of a formation of sufficient porosity and permeability to form a petroleum reservoir.
"IQE"	Independent Qualified Estimator.
"Leases"	Full or partial interests in oil or natural gas properties authorizing the owner of the lease to drill for, produce and sell oil and natural gas upon payment of rental, bonus, royalty or any other payments.
"MBOE"	Thousand barrels of oil equivalent. Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency.
"MMBOE"	Million barrels of oil equivalent. Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency.
"Mcf"	Thousand cubic feet.
"MMBbls"	Million barrels.
"MMBtu"	Million British thermal units.
"MMCFD"	Million cubic feet per day.
"Natural gas"	Natural gas is a combination of light hydrocarbons that, in average pressure and temperature conditions, is found in a gaseous state. In nature, it is found in underground accumulations, and may potentially be dissolved in oil or may also be found in its gaseous state.

"Net pay thickness"	The vertical extent of the effective hydrocarbon-bearing rock (expressed in feet). The net pay thickness encountered by an exploration well may differ from the mean net pay thickness of the prospect due to several factors, including the relative location of the exploration well on the structure, potential thickness variations that may occur across the prospect and the extent to which potential reservoir horizons are penetrated.
"NORM"	Naturally occurring radioactive materials.
"NSAI"	Netherland, Sewell & Associates, Inc.
"Oil and natural gas lease"	A legal instrument executed by a mineral owner granting the right to another to explore, drill, and produce subsurface oil and natural gas. An oil and natural gas lease embodies the legal rights, privileges and duties pertaining to the lessor and lessee.
"OPEC"	Organization of the Petroleum Exporting Countries.
"Operator"	A party that has been designated as manager for exploration, drilling, and/or production on a lease. The operator is the party that is responsible for (a) initiating and supervising the drilling and completion of a well and/or (b) maintaining the producing well.
"Play"	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.
"Porosity"	Porosity is the percentage of pore volume or void space, or that volume within rock that can contain fluids. Porosity can be a relic of deposition (primary porosity, such as space between grains that were not compacted together completely) or can develop through alteration of the rock (secondary porosity, such as when feldspar grains or fossils are preferentially dissolved from sandstones).
"Productive well"	A well that has been drilled to the targeted depth and proves, in our opinion, to be capable of producing either oil or gas in sufficient quantities that will justify completion as an oil or gas well.
"Prospect(s)"	Potential trap which may contain hydrocarbons and is supported by the necessary amount and quality of geologic and geophysical data to indicate a probability of oil and/or natural gas accumulation ready to be drilled. The five required elements (generation, migration, reservoir, seal and trap) must be present for a prospect to work and if any of them fail neither oil nor natural gas will be present, at least not in commercial volumes.
"Proved reserves"	Estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be economically recoverable in future years from known reservoirs under existing economic and operating conditions, as well as additional reserves expected to be obtained through confirmed improved recovery techniques, as defined in SEC Regulation S-X 4-10(a)(2).
"PSA"	Production Sharing Agreement.
"Reservoir"	A subsurface body of rock having sufficient porosity and permeability to store and to allow for the mobility of fluids/hydrocarbons included in its pores.
"Royalty"	A fractional undivided interest in the production of oil and natural gas wells, or the proceeds therefrom to be received free and clear of all costs of development, operations or maintenance.
"RPC"	Reserves Process Chair.
"SEC"	United States Securities and Exchange Commission.
"Shut in"	To close the valves on a well so that it stops producing.
"Spud"	The very beginning of drilling operations of a new well, occurring when the drilling bit penetrates the surface utilizing a drilling rig capable of drilling the well to the authorized total depth.
"Standardized Measure"	The present value of estimated future net cash inflows from proved oil and natural gas reserves, less future development and production costs and future income tax expenses, discounted at 10% per annum to reflect timing of future net cash flows.
"Working interest"	An interest in an oil and natural gas lease entitling the holder at its expense to conduct drilling and production operations on the leased property and to receive the net revenues attributable to such interest, after deducting the landowner's royalty, any overriding royalties, production costs, taxes and other costs.
"Workover"	Operations on a producing well to restore or increase production.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) The following documents are filed as part of this Annual Report on Form 10-K:

(1) Financial Statements

Cobalt International Energy, Inc.

(2) Financial Statement Schedule

Not applicable.

(3) Exhibits

The following exhibits are filed with this Annual Report on Form 10-K or incorporated by reference:

Exhibit Number	Description of Document
	Certificate of Incorporation, Bylaws and Specimen Stock Certificate
3.1	Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
3.2	By-laws of the Company (incorporated by reference to Exhibit 3 to the Company's Registration Statement on Form 8-A filed December 11, 2009 (File No. 001-34579))
4.1	Specimen stock certificate (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
	Instruments relating to Debt Securities
4.2	Senior Debt Indenture, dated as of December 17, 2012 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.3	First Supplemental Indenture, dated as of December 17, 2012 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.4	Form of 2.625% Convertible Senior Note due 2019 (incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.5	Second Supplemental Indenture, dated as of May 13, 2014 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed May 13, 2014 (File No. 001-34579))
4.6	Form of 3.125% Convertible Senior Note due 2024 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed May 13, 2014 (File No. 001-34579))
	Operating Agreements
10.1	Purchase and Sale Agreement, dated August 22, 2015, by and between Cobalt International Energy Angola Ltd. and Sociedade Nacional de Combustíveis de Angola—Empresa Pública (Sonangol E.P.) (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed November 3, 2015 (File No. 001-34579))
10.2	Restated Overriding Royalty Agreement, dated February 13, 2009, by and between Whitton Petroleum Services Limited, CIE Angola Block 9 Ltd., CIE Angola Block 20 Ltd., CIE Angola Block 21 Ltd., and Cobalt International Energy, L.P. (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed November 3, 2015 (File No. 001-34579))
10.3	Borrowing Base Facility Agreement, dated May 29, 2015, by and between Cobalt GOM #1 LLC, Cobalt International Energy, Inc., Société Générale, as administrative agent, and various other lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed June 3, 2015 (File No. 001-34579))
10.4	Risk Services Agreement relating to Block 9, between CIE Angola Block 9 Ltd., Sonangol, Sonangol Pesquisa e Produção, S.A., Nazaki Oil and Gás and Alper Oil, Lda (incorporated by reference to Exhibit 10.7 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.5	Risk Services Agreement relating to Block 21, between CIE Angola Block 21 Ltd., Sonangol, Sonangol Pesquisa e Produção, S.A., Nazaki Oil and Gás and Alper Oil, Lda (incorporated by reference to Exhibit 10.8 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))

Exhibit Number	Description of Document
10.6	Production Sharing Contract, dated December 20, 2011, between CIE Angola Block 20 Ltd., Sociedade Nacional de Combustíveis de Angola—Empresa Pública, Sonangol Pesquisa e Produção, S.A., BP Exploration Angola (Kwanza Benguela) Limited, and China Sonangol International Holding Limited (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.7	Exploration and Production Sharing Contract, dated December 13, 2006, between the Republic of Gabon and Total Gabon, S.A. (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.8	Assignment Agreement, dated November 29, 2007, between CIE Gabon Diaba Ltd. and Total Gabon, S.A. (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.9	Simultaneous Exchange Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference to Exhibit 10.7 to the Company's Registration Statement on Form S-1/A filed October 9, 2009 (File No. 333-161734))
10.10	Gulf of Mexico Program Management and AMI Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1/A filed October 9, 2009 (File No. 333-161734))
10.11	Offshore Daywork Drilling Contract, dated May 3, 2008, between the Partnership and Ensco Offshore Company (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.12	International Daywork Drilling Contract—Offshore, dated November 8, 2010 between CIE Angola Block 21 Ltd. and Z North Sea Ltd. (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed November 12, 2010 (File No. 001-34579)).
10.13	Offshore Drilling Contract between CIE Angola Block 21 Ltd. and Universal Energy Resources, Inc., dated July 30, 2012 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed October 30, 2012 (File No. 001-34579))
10.14	Offshore Drilling Contract between Cobalt International Energy, L.P. and Rowan Reliance Limited, dated August 5, 2013 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed October 29, 2013 (File No. 001-34579))
	Agreements with Stockholders and Directors
10.15	Amended and Restated Stockholders Agreement, dated February 21, 2013, among the Company and the stockholders that are signatory thereto (incorporated by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.16	Registration Rights Agreement, dated December 15, 2009, among the Company and the parties that are signatory thereto (incorporated by reference to Exhibit 10.31 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.17	Form of Director Indemnification Agreements (incorporated by reference to Exhibit 10.19 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
	Management Contracts/Compensatory Plans or Arrangements
10.18†	Amended and Restated Long Term Incentive Plan of the Company (incorporated by reference to Exhibit 10.15 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.19†	Form of Restricted Stock Award Agreements relating to the Class B interests (incorporated by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.20†	Form of Restricted Stock Award Agreements relating to the Class C interests (incorporated by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))

Exhibit Number	Description of Document
10.21†	Form of Restricted Stock Award Agreements relating to the Class D interests (incorporated by reference to Exhibit 10.12 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.22†	Form of Non-Qualified Stock Option Award Agreement (incorporated by reference to Exhibit 10.26 to the Company's Annual Report on Form 10-K filed March 1, 2011 (File No. 001-34579)).
10.23†	Form of Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.27 to the Company's Annual Report on Form 10-K filed March 1, 2011 (File No. 001-34579)).
10.24†	Deferred Compensation Plan of the Company (incorporated by reference to Exhibit 10.35 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.25†	Annual Incentive Plan of the Company (incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.26†	Employment Agreement, dated November 12, 2009, among the Company, the Partnership and Joseph H. Bryant (incorporated by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.27†	Employment Agreement, dated October 23, 2009, among the Company, the Partnership and James H. Painter (incorporated by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.28†	Employment Agreement, dated October 23, 2009, among the Company, the Partnership and James W. Farnsworth (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.29†	Severance Agreement, dated October 23, 2009, among the Company, the Partnership and John P. Wilkirson (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.30†	Employment Agreement, dated September 6, 2011, between the Company and Van P. Whitfield (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed September 8, 2011 (File No. 001-34579))
10.31†	Severance Agreement, dated April 1, 2010, between the Company and Michael D. Drennon (incorporated by reference to Exhibit 10.30 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.32†	Form of Amendment to Employment Agreements with Joseph H. Bryant, James H. Painter and James W. Farnsworth and Severance Agreements with Samuel H. Gillespie and John P. Wilkirson (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed November 12, 2010 (File No. 001-34579)).
10.33†	Non-Employee Directors Compensation Plan (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed January 29, 2010 (File No. 001-34579))
10.34†	Non-Employee Directors Deferral Plan (incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K filed January 29, 2010 (File No. 001-34579))
10.35†	Form of Restricted Stock Unit Award Notification under the Non- Employee Directors Compensation Plan (incorporated by reference to Exhibit 99.4 to the Company's Current Report on Form 8-K filed January 29, 2010 (Filed No. 001-34579))
10.36†	Employment Agreement Extension, dated November 3, 2014, between the Company and Van P. Whitfield (incorporated by reference to Exhibit 10.33 to the Company's Annual Report on Form 10-K filed February 23, 2015 (File No. 001-34579))
10.37†	Employment Agreement, dated November 3, 2014, between the Company and James W. Farnsworth (incorporated by reference to Exhibit 10.34 to the Company's Annual Report on Form 10-K filed February 23, 2015 (File No. 001-34579))
10.38†	Employment Agreement, dated November 3, 2014, between the Company and James H. Painter (incorporated by reference to Exhibit 10.35 to the Company's Annual Report on Form 10-K filed

Exhibit Number	Description of Document
	February 23, 2015 (File No. 001-34579))
10.39†	Form of Special Restricted Stock Award Agreement, dated January 15, 2015 (incorporated by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K filed February 23, 2015 (File No. 001-34579))
10.40†	Form of Special Non-Qualified Stock Option Award Agreement, dated January 15, 2015 (incorporated by reference to Exhibit 10.37 to the Company's Annual Report on Form 10-K filed February 23, 2015 (File No. 001-34579))
10.41†	Form of Stock Appreciation Right Award Agreement under the Company’s Long Term Incentive Plan (incorporated by reference to Exhibit 10.38 to the Company's Annual Report on Form 10-K filed February 23, 2015 (File No. 001-34579))
10.42†	Form of Restricted Stock Unit Award Agreement under the Company’s Long Term Incentive Plan (incorporated by reference to Exhibit 10.39 to the Company's Annual Report on Form 10-K filed February 23, 2015 (File No. 001-34579))
10.43†	Form of Restricted Stock Award Agreement under the Company’s Long Term Incentive Plan (incorporated by reference to Exhibit 10.40 to the Company's Annual Report on Form 10-K filed February 23, 2015 (File No. 001-34579))
10.44†	Separation Agreement, dated August 24, 2015, by and between Cobalt International Energy, Inc. and John P. Wilkirson (incorporated by reference to Exhibit 10.3 to the Company’s Quarterly Report on Form 10-Q filed November 3, 2015 (File No. 001-34579))
10.45†	Severance Agreement, dated August 25, 2015, by and between Cobalt International Energy, Inc. and Shannon E. Young, III (incorporated by reference to Exhibit 10.4 to the Company’s Quarterly Report on Form 10-Q filed November 3, 2015 (File No. 001-34579))
10.46†	Cobalt International Energy, Inc. 2015 Long Term Incentive Plan (incorporated by reference to Exhibit 99.1 to the Company's Registration Statement on Form S-8 filed May 5, 2015 (File No. 333-203877))
10.47†*	Form of Special Restricted Stock Award Agreement, dated January 15, 2016
10.48†*	Form of Special Non-Qualified Stock Option Award Agreement, dated January 15, 2016
10.49†*	Form of Restricted Stock Unit Award Agreement under the Company’s 2015 Long-Term Incentive Plan
	Other Exhibits
12.1*	Statement re: Computation of Ratio of Earnings to Fixed Charges
21.1*	List of Subsidiaries
23.1*	Consent of Ernst & Young LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of the Chief Executive Officer pursuant to Rule 13a- 14(a)/15d-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of the Chief Financial Officer pursuant to Rule 13a- 14(a)/15d-14(a) of the Securities Exchange Act of 1934
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document

Exhibit Number	Description of Document
101.CAL *	XBRL Calculation Linkbase Document
101.DEF *	XBRL Definition Linkbase Document
101.LAB *	XBRL Labels Linkbase Document
101.PRE *	XBRL Presentation Linkbase Document

* Filed herewith.

** Furnished herewith.

† Management contract or compensatory plan or arrangement required to be filed as an exhibit to this Form 10-K pursuant to Item 15(b).

SIGNATURES

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

Cobalt International Energy, Inc.

By: /s/ JOSEPH H. BRYANT
Name: Joseph H. Bryant
Title: *Chairman of the Board of Directors and Chief Executive Officer*

Dated: February 22, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ JOSEPH H. BRYANT Joseph H. Bryant	Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)	February 22, 2016
/s/ SHANNON E. YOUNG, III Shannon E. Young, III	Chief Financial Officer and Executive Vice President (Principal Financial Officer and Principal Accounting Officer)	February 22, 2016
/s/ JACK E. GOLDEN Jack E. Golden	Director	February 22, 2016
/s/ KAY BAILEY HUTCHISON Kay Bailey Hutchison	Director	February 22, 2016
/s/ JON A. MARSHALL Jon A. Marshall	Director	February 22, 2016
/s/ KENNETH W. MOORE Kenneth W. Moore	Director	February 22, 2016
/s/ MYLES W. SCOGGINS Myles W. Scoggins	Director	February 22, 2016
/s/ WILLIAM P. UTT William P. Utt	Director	February 22, 2016
/s/ D. JEFF VAN STEENBERGEN D. Jeff van Steenbergen	Director	February 22, 2016
/s/ MARTIN H. YOUNG, JR. Martin H. Young, Jr.	Director	February 22, 2016

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS
COBALT INTERNATIONAL ENERGY, INC.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined by Securities and Exchange Commission rules adopted under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States (GAAP). Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of management and our directors; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the consolidated financial statements.

There are inherent limitations to the effectiveness of internal control over financial reporting, however well designed, including the possibility of human error and the possible circumvention of or overriding of controls. The design of an internal control system is also based in part upon assumptions and judgments made by management about the likelihood of future events, and there can be no assurance that an internal control will be effective under all potential future conditions. As a result, even an effective system of internal controls can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control—Integrated Framework (2013 Framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our evaluation, we concluded that our internal control over financial reporting was effective as of December 31, 2015. The effectiveness of our internal control over financial reporting as of December 31, 2015 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

/s/ JOSEPH H. BRYANT	/s/ SHANNON E. YOUNG, III
Joseph H. Bryant	Shannon E. Young, III
Chairman of the Board of Directors and Chief Executive Officer	*Chief Financial Officer and Executive Vice President*

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Cobalt International Energy, Inc.

We have audited Cobalt International Energy, Inc.'s internal control over financial reporting as of December 31, 2015 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Cobalt International Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, Cobalt International Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2015 consolidated financial statements of Cobalt International Energy, Inc. and our report dated February 22, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 22, 2016

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Cobalt International Energy, Inc.

We have audited the accompanying consolidated balance sheets of Cobalt International Energy, Inc. (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2015. 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 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Cobalt International Energy, Inc. at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Cobalt International Energy, Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 22, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 22, 2016

Cobalt International Energy, Inc.
Consolidated Balance Sheets

	December 31, 2015	December 31, 2014
	($ in thousands, except per share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 71,593	$ 246,704
Restricted cash and cash equivalents	252,950	—
Joint interest and other receivables	54,709	13,575
Prepaid expenses and other current assets	43,881	3,842
Inventory	26,113	35,093
Short-term investments	885,994	1,530,206
Current assets held for sale	1,811,051	173,714
Total current assets	3,146,291	2,003,134
Property, plant, and equipment:		
Oil and gas properties, successful efforts method of accounting, net of accumulated depletion of $-0-	893,734	711,238
Other property and equipment, net of accumulated depreciation and amortization of $6,647 and $5,245, as of December 31, 2015 and 2014, respectively	2,202	3,416
Total property, plant, and equipment, net	895,936	714,654
Long-term investments	—	326,047
Deferred income taxes	—	30,334
Other assets	51,876	49,032
Long-term assets held for sale	—	1,327,661
Total assets	$ 4,094,103	$ 4,450,862
Liabilities and Stockholders' Equity		
Current liabilities:		
Trade and other accounts payable	$ 856	$ 70
Accrued liabilities	126,323	98,016
Deferred Angola sales proceeds	250,000	—
Deferred income taxes	—	30,334
Current liabilities held for sale	250,839	175,180
Total current liabilities	628,018	303,600
Long-term debt	2,014,779	1,928,528
Asset retirement obligations	3,167	—
Other long-term liabilities	2,002	2,172
Long-term liabilities held for sale	—	102,296
Total long-term liabilities	2,019,948	2,032,996
Stockholders' Equity:		
Common stock, $0.01 par value per share; 2,000,000,000 shares authorized 408,740,182 and 408,505,079 issued and outstanding as of December 31, 2015 and 2014, respectively	4,088	4,085
Additional paid-in capital	4,164,097	4,137,803
Accumulated deficit	(2,722,048)	(2,027,622)
Total stockholders' equity	1,446,137	2,114,266
Total liabilities and stockholders' equity	$ 4,094,103	$ 4,450,862

See accompanying notes.

Cobalt International Energy, Inc.
Consolidated Statements of Operations

	Year Ended December 31,		
	2015	2014	2013
	($ in thousands except per share data)		
Oil and gas revenue	$ —	$ —	$ —
Operating costs and expenses:			
Seismic and exploration	45,318	41,431	49,847
Dry hole expense and impairment	308,960	133,223	224,105
General and administrative	87,031	72,090	72,895
Accretion expense	99	—	—
Depreciation and amortization	1,403	1,694	1,328
Total operating costs and expenses	442,811	248,438	348,175
Operating income (loss)	(442,811)	(248,438)	(348,175)
Other income (expense):			
Gain (loss) on sale of assets	1,555	—	2,996
Interest income	6,087	5,958	6,043
Interest expense	(63,376)	(74,768)	(65,376)
Total other income (expense)	(55,734)	(68,810)	(56,337)
Net income (loss) from continuing operations before income tax	(498,545)	(317,248)	(404,512)
Income tax expense	—	—	—
Net income (loss) from continuing operations	(498,545)	(317,248)	(404,512)
Net income (loss) from discontinued operations, net of income tax	(195,881)	(193,515)	(184,512)
Net income (loss)	$ (694,426)	$ (510,763)	$ (589,024)
Basic and diluted income (loss) per share from continuing operations	$ (1.22)	$ (0.78)	$ (0.99)
Basic and diluted income (loss) per share from discontinued operations	$ (0.48)	$ (0.47)	$ (0.46)
Basic and diluted income (loss) per share	$ (1.70)	$ (1.25)	$ (1.45)
Basic and diluted weighted average common shares outstanding	408,535,122	407,116,144	406,839,997

See accompanying notes.

Cobalt International Energy, Inc.
Consolidated Statements of Changes in Stockholders' Equity

	Common Stock	Additional Paid-in Capital	Accumulated Deficit	Total
	($ in thousands)			
Balance, December 31, 2012	$ 4,066	$ 3,612,987	$ (927,835)	$ 2,689,218
Common stock issued for restricted stock and stock options	3	(3)	—	—
Equity based compensation	—	28,754	—	28,754
Exercise of stock options	—	198	—	198
Net income (loss)	—	—	(589,024)	(589,024)
Balance, December 31, 2013	$ 4,069	$ 3,641,936	$ (1,516,859)	$ 2,129,146
Common stock issued for restricted stock and stock options	16	(16)	—	—
Equity based compensation	—	31,742	—	31,742
Exercise of stock options	—	33	—	33
Common stock withheld for taxes on equity based compensation	—	(630)	—	(630)
Conversion option relating to 3.125% convertible senior notes due 2024, net of allocated costs	—	464,738	—	464,738
Net income (loss)	—	—	(510,763)	(510,763)
Balance, December 31, 2014	$ 4,085	$ 4,137,803	$ (2,027,622)	$ 2,114,266
Common stock issued for restricted stock and stock options	3	(3)	—	—
Equity based compensation	—	26,297	—	26,297
Net income (loss)	—	—	(694,426)	(694,426)
Balance, December 31, 2015	$ 4,088	$ 4,164,097	$ (2,722,048)	$ 1,446,137

See accompanying notes.

Cobalt International Energy, Inc.
Consolidated Statements of Cash Flows

	Year Ended December 31, 2015	2014	2013
		($ in thousands)	
Cash flows provided from operating activities			
Net income (loss)	$ (694,426)	$ (510,763)	$ (589,024)
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation and amortization	1,403	1,694	1,328
Accretion expense	99	—	—
Loss from discontinued operations	195,881	193,515	184,512
Dry hole expense and impairment	308,960	133,223	224,105
Gain on sale of assets	(1,555)	—	(2,996)
Equity based compensation	26,297	31,742	28,754
Amortization of premium (accretion of discount) on investments	14,323	19,538	22,351
Amortization of debt discount	89,662	71,330	46,847
Changes in operating assets and liabilities:			
Joint interest and other receivables	(41,134)	46,177	(714)
Inventory	6,895	(6,143)	9,203
Prepaid expense and other current assets	(40,039)	36,326	(22,331)
Deferred charges	(2,187)	9,731	(21,600)
Trade and other accounts payable	785	(19,849)	(22,593)
Accrued liabilities and other	(388)	3,465	2,236
Net cash provided by (used in) operating activities – continuing operations	(135,424)	9,986	(139,922)
Net cash provided by (used in) operating activities – discontinued operations	(116,518)	(74,510)	(76,446)
Net cash provided by (used in) operating activities	(251,942)	(64,524)	(216,368)
Cash flows from investing activities			
Capital expenditures for oil and gas properties	(35,190)	(27,784)	(37,584)
Capital expenditures for other property and equipment	(188)	(544)	(1,981)
Exploration wells drilling in process	(421,036)	(209,283)	(241,312)
Proceeds from sale of oil and gas properties	—	—	3,006
Change in restricted funds	(48,999)	(112,434)	(205)
Proceeds from maturity of investment securities	1,894,562	1,700,123	1,366,977
Purchase of investment securities	(892,577)	(2,129,453)	(1,896,591)
Net cash provided by (used in) investing activities – continuing operations	496,572	(779,375)	(807,690)
Net cash provided by (used in) investing activities – discontinued operations	(415,673)	(344,240)	(185,724)
Net cash provided by (used in) investing activities	80,899	(1,123,615)	(993,414)
Cash flows from financing activities			
Proceeds from public offering, net of costs	—	—	—
Payment of debt issuance costs	(4,068)	—	—
Proceeds from debt offering, net of costs	—	1,269,778	—
Proceeds from exercise of stock options	—	33	(992)
Payments for common stock withheld for taxes on equity based compensation	—	(631)	—
Net cash provided by (used in) financing activities	(4,068)	1,269,180	(992)
Net increase (decrease) in cash and cash equivalents	(175,111)	81,041	(1,210,774)
Cash and cash equivalents, beginning of period	246,704	165,663	1,376,437
Cash and cash equivalents, end of period	$ 71,593	$ 246,704	$ 165,663
Cash paid for interest	$ 78,410	$ 56,764	$ 34,615
Non-Cash Disclosures			
Change in accrued capital expenditures	$ (47,580)	$ (56,129)	$ 58,769
Transfer of investment securities to and from restricted funds	$ 46,049	$ 112,434	$ 26

See accompanying notes.

1. Summary of Significant Accounting Policies

Description of Operations

Cobalt International Energy, Inc. (the "Company") is an independent exploration and production company with operations in the deepwater U.S. Gulf of Mexico and offshore Angola and Gabon in West Africa.

On August 22, 2015, Cobalt International Energy Angola Ltd., a wholly owned subsidiary of the Company, executed a purchase and sale agreement with Sociedade Nacional de Combustíveis de Angola—Empresa Pública ("Sonangol") for the sale by the Company to Sonangol of the entire issued and outstanding share capital of its indirect wholly owned subsidiaries CIE Angola Block 20 Ltd. and CIE Angola Block 21 Ltd., which respectively hold the Company's 40% working interest in each of Block 20 and Block 21 offshore Angola (the "Angola Transaction"). The Angola Transaction is subject to Angolan government approvals. Following the transfer of the share capital of CIE Angola Block 20 Ltd. and CIE Angola Block 21 Ltd., the Company will also relinquish its working interest in Block 9 offshore Angola to Sonangol. The Company's working interests in Blocks 9, 20, and 21 offshore Angola have been classified as "held for sale" on the consolidated balance sheet. The results of operations associated with Blocks 9, 20 and 21 offshore Angola have been presented as discontinued operations in the accompanying consolidated statement of operations. For more information, see *Note 11—Angola Transaction*. Historically, the Company's Angolan subsidiaries constituted a significant portion of its West Africa segment. The Company's operations in Gabon, which are deemed immaterial, have been combined with its United States segment and are reported as one segment.

The terms "Company," "Cobalt," "we," "us," "our," "ours," and similar terms refer to Cobalt International Energy, Inc. unless the context indicates otherwise.

Basis of Presentation

Our consolidated financial statements include the accounts of Cobalt International Energy, Inc. and its majority-owned subsidiaries. All significant intercompany transactions and amounts have been eliminated for all years presented. The Company's consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles ("GAAP") and the appropriate rules and regulations of the Securities and Exchange Commission ("SEC").

Certain prior year amounts have been reclassified for consistency with the current period presentation due to the Angolan Transaction (Refer to *Note 11 - Angola Transaction*) resulting in discontinued operations and assets held for sale presentation. These reclassifications had no effect on the reported results of operations.

Recently Issued Accounting Standards

In April 2015, Financial Accounting Standards Board (FASB) amended Accounting Standard Codification Subtopic No. 835-30, *Interest—Imputation of Interest* (the "ASC Subtopic 835-30"). The amendments require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments. The amendments under ASC Subtopic 835-30 are effective for financial statements issued for fiscal years beginning after December 15, 2015 and interim periods within those fiscal years. However, early adoption is permitted for financial statements that have not been previously issued. The Company expects to comply with the amendments to ASC Subtopic 835-30 for the financial statements at its effective date beginning after December 15, 2015. We do not expect the adoption of ASC 835-30 to have a material impact on the Company's financial statements.

In July 2015, the FASB issued Accounting Standards Update (ASU) 2015-11, "Accounting for Inventory" (ASU 2015-11), which requires entities to measure most inventory at lower of cost or net realizable value. ASU 2015-11 defines net realizable value as "the estimated selling prices in the ordinary course of business, less reasonably predictable cost of completion, disposal and transportation." ASU 2015-11 is effective prospectively for interim and annual periods beginning after December 15, 2016. The Company expects to comply with the amendments to ASC 2015-11 at its effective date beginning after December 15, 2016. We do not expect the adoption of ASC 2015-11 to have a material impact on the Company's financial statements.

1. Summary of Significant Accounting Policies (Continued)

In November 2015, the FASB issued ASU 2015-17, "Income Taxes" (ASU 2015-17), which requires that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. The amendments in this Update apply to all entities that present a classified statement of financial position. The current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount is not affected by the amendments. For public business entities, the amendments are effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Earlier application is permitted for all entities as of the beginning of an interim or annual reporting period. The amendments may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. If an entity applies the guidance prospectively, the entity should disclose in the first interim and first annual period of change, the nature of and reason for the change in accounting principle and a statement that prior periods were not retrospectively adjusted. If an entity applies the guidance retrospectively, the entity should disclose in the first interim and first annual period of change the nature of and reason for the change in accounting principle and quantitative information about the effects of the accounting change on prior periods. The Company early adopted ASU Subtopic 2015-17 beginning December 31, 2015 and will apply this update prospectively.

Use of Estimates

The preparation of financial statements in conformity with United States generally accepted accounting principles (“GAAP”) requires the Company to make estimates and assumptions that affect the reported amounts of assets including proved reserves and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates the Company makes include (a) accruals related to expenses, (b) assumptions used in estimating fair value of equity based awards and the fair value of the liability component of the convertible senior notes and (c) assumptions used in impairment testing. Although the Company believes these estimates are reasonable, actual results could differ from these estimates.

Fair Value Measurements

The fair values of the Company’s cash and cash equivalents, joint interest and other receivables, restricted funds and investments approximate their carrying amounts due to their short-term duration. The hierarchy below lists three levels of fair value based on the extent to which inputs used in measuring fair value are observable in the market. The Company categorizes each of its fair value measurements as applicable to one of these three levels based on the lowest level input that is significant to the fair value measurement in its entirety. The levels are:

Level 1—Quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities. This category includes the Company’s cash and money market funds.

Level 2—Quoted prices in non-active markets or in active markets for similar assets or liabilities, and inputs other than quoted prices that are observable, for the asset or liability, either directly or indirectly for substantially the full contractual term of the asset or liability being measured. This category includes the Company’s U.S. Treasury bills, U.S. Treasury notes, U.S. Government agency securities, commercial paper, corporate bonds and certificates of deposits.

Level 3—Inputs that are generally unobservable and typically reflect management’s estimate of assumptions that market participants would use in pricing the asset or liability. The Company does not currently have any financial instruments categorized as Level 3.

Revenue Recognition

The Company will follow the “sales” (or cash) method of accounting for oil and gas revenues. Under this method, the Company will recognize revenues on the volumes sold. The volumes sold may be more or less than the volumes to which the Company is entitled based on its ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. For the years ended December 31, 2015, 2014 and 2013, no revenues have been recognized in these consolidated financial statements.

1. Summary of Significant Accounting Policies (Continued)

Cash and Cash Equivalents

Cash and cash equivalents consist of demand deposits and funds invested in highly liquid instruments with maturities of three months or less from the date of purchase. Demand deposits typically exceed federally insured limits; however, the Company periodically assesses the financial condition of the institutions where these funds are held as well as the credit ratings of the issuers of the highly liquid instruments and believes that the credit risk is minimal.

Investments

The Company's investments consist entirely of debt securities. The Company considers all highly liquid interest-earning investments with a maturity of three months or less at the date of purchase to be cash equivalents. Investments with original maturities of greater than three months and remaining maturities of less than one year are classified as short-term investments. Investments with maturities beyond one year are classified as long-term investments. The debt securities are carried at amortized cost and classified as held-to-maturity securities as the Company has the positive intent and ability to hold them until they mature. The net carrying value of held-to-maturity securities is adjusted for amortization of premiums and accretion of discounts to maturity over the life of the securities. Held-to-maturity securities are stated at amortized cost, which approximates fair market value as of December 31, 2015 and 2014. Income related to these securities is reported as a component of interest income in the Company's consolidated statement of operations. *See Note 6—Investments*.

Investments are considered to be impaired when a decline in fair value is determined to be other-than-temporary. The Company conducts a regular assessment of its debt securities with unrealized losses to determine whether securities have other-than-temporary impairment ("OTTI"). This assessment considers, among other factors, the nature of the securities, credit rating or financial condition of the issuer, the extent and duration of the unrealized loss, market conditions and whether the Company intends to sell or whether it is more likely than not that the Company will be required to sell the debt securities. As of December 31, 2015 and 2014, the Company has no OTTI in its debt securities.

Capitalized Interest

For exploration and development projects that have not commenced production, interest is capitalized as part of the historical cost of developing and constructing assets. Capitalized interest is determined by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred. Once an asset subject to interest capitalization is completed and placed in service, the associated capitalized interest is expensed through depreciation or impairment. *See Note 8—Property, Plant, and Equipment and Note 10—Long-term Debt*.

Joint Interest and Other Receivables

Joint interest and other receivables result primarily from billing shared costs under the respective operating agreements to the Company's partners. These receivables are usually settled within 30 days of the invoice date.

Property, Plant, and Equipment

The Company uses the "successful efforts" method of accounting for its oil and gas properties. Acquisition costs for unproved leasehold properties and costs of drilling exploration wells are capitalized pending determination of whether proved reserves can be attributed to the areas as a result of drilling those wells. Under the successful efforts method of accounting, proved leasehold costs are capitalized and amortized over the proved developed and undeveloped reserves on a units-of-production basis. Successful drilling costs, costs of development and developmental dry holes are capitalized and amortized over the proved developed reserves on a units-of-production basis. When circumstances indicate that proved oil and gas properties may be impaired, the Company compares expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the unamortized capitalized cost of the asset. If the expected undiscounted future cash flows, based on the Company's estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach described in the Fair Value Measurement Topic of the ASC. Significant unproved leasehold costs are capitalized and are not amortized, pending an evaluation of their exploration potential. Unproved leasehold costs are assessed periodically to determine if an impairment of the cost of individual properties has occurred. Factors taken into account for impairment analysis include results of the technical studies

1. Summary of Significant Accounting Policies (Continued)

conducted, lease terms and management's future exploration plans. The cost of impairment is charged to expense in the period in which it occurs. Costs incurred for exploration dry holes, geological and geophysical work (including the cost of seismic data), and delay rentals are charged to expense as incurred. Costs of other property and equipment are depreciated on a straight-line basis based on their respective useful lives.

Asset Retirement Obligations

The Company expects to have significant obligations under its lease agreements and federal regulation to remove its equipment and restore land or seabed at the end of oil and natural gas production operations. These asset retirement obligations ("ARO") are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and natural gas platforms. Estimating the future restoration and removal cost is difficult and requires the Company to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulation often have vague descriptions of what constitutes removal. Asset removal technologies and cost are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. The Company records a separate liability for the estimated fair value of its asset retirement obligations, with an offsetting increase to the related oil and natural gas properties. The cost of the related oil and natural gas asset, including the asset retirement cost, is depreciated over the useful life of the asset. The estimated fair value of asset retirement obligations is measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Inherent to the present value calculation are numerous estimates, assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted risk-free rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the abandonment liability, the Company will make corresponding adjustments to both the asset retirement obligation and the related oil and natural gas property asset balance. Increases in the discounted abandonment liability resulting from the passage of time will be reflected as additional accretion in the consolidated statements of operations.

During the quarterly period ended September 30, 2015, the Company recognized a retirement obligation for its Heidelberg field.

The following summarizes the changes in the asset retirement obligation for the year ended December 31, 2015:

	December 31, 2015
	($ in thousands)
Beginning of period	—
Liabilities incurred	3,068
Accretion	99
End of period	$ 3,167

Inventory

Inventories consist of various tubular products that are used in the Company's drilling programs. The products are stated at the average cost. Cost is determined using a weighted average method comprised of the purchase price and other directly attributable costs.

Income Taxes

The Company applies the liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are determined by applying tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the financial statements. Since the Company currently has no production activities and there can be no assurance that the Company will generate any earnings or any specific level of earnings in future years, the Company has established a valuation allowance that equals its net deferred tax assets. *See Note 16 – Income Taxes.*

1. Summary of Significant Accounting Policies (Continued)

Equity-Based Compensation

The Company accounts for stock-based compensation at fair value. The Company grants various types of stock-based awards including stock options, restricted stock and performance-based awards. The fair value of stock option awards is determined using the Black-Scholes-Merton option-pricing model. For restricted stock awards with market conditions, the fair value of the awards is measured using the asset-or-nothing option pricing model. Restricted stock awards without market conditions and the performance-based awards are valued using the market price of the Company's common stock on the grant date. The Company records compensation cost, net of estimated forfeitures, on a straight-line basis for stock-based compensation awards over the requisite service period except for performance-based awards. For performance-based awards, compensation cost is recognized over the requisite service period as and when the Company determines that the achievement of the performance condition is probable, using the per-share fair value measured at grant date. *See Note 14 – Equity Based Compensation.*

Earnings (Loss) Per Share

Basic income (loss) per share was calculated by dividing net income or loss applicable to common shares by the weighted average number of common shares outstanding during the periods presented. The calculation of diluted income (loss) per share includes the potential dilutive impact of non-vested restricted shares, non-vested restricted stock units, outstanding stock options, the 2.625% convertible senior notes due 2019 and the 3.125% convertible senior notes due 2024, during the period, unless their effect is anti-dilutive. For the year ended December 31, 2015, 9,653,026 shares of non-vested restricted stock, non-vested restricted stock units, outstanding stock options, the 2.625% convertible senior notes due 2019 and the 3.125% convertible senior notes due 2024, were excluded from the diluted income (loss) per share because they are anti-dilutive. For the year ended December 31, 2014, 5,997,374 shares of non-vested restricted stock, non-vested restricted stock units, outstanding stock options and the 2.625% convertible senior notes due 2019 were excluded from the diluted income (loss) per share because they are anti-dilutive. For the year ended December 31, 2013, 6,735,046 shares of non-vested restricted stock, non-vested restricted stock units and outstanding stock options were excluded from the diluted income (loss) per share because they are anti-dilutive.

Operating Costs and Expenses

Expenses consist primarily of the costs of acquiring and processing of geological and geophysical data, exploration, and appraisal drilling expenses, consultants, telecommunications, payroll and benefit costs, information system and legal costs, office rent, contract costs, and bookkeeping and audit fees.

2. Cash and Cash Equivalents

As of December 31, 2015 and 2014, cash and cash equivalents consisted of the following:

	December 31, 2015	December 31, 2014
	($ in thousands)	
Cash at banks	$ 33,173	$ 45,733
Money market funds	—	122,218
Held-to-maturity securities(1)	38,420	78,753
	$ 71,593	$ 246,704

(1) These securities mature three months or less from the date of purchase.

3. Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents consisted of the following:

	December 31, 2015	December 31, 2014
	($ in thousands)	
Angolan sale proceeds	$ 250,000	—
American Express Bank pledge agreement	750	—
Citibank commercial card agreement	2,200	—
Total restricted funds(1)	$ 252,950	$ —

(1) Pursuant to the purchase and sale agreement governing the Angola Transaction, the Company received the First Payment of $250 million during the quarterly period ended September 30, 2015. See *Note 11—Angola Transaction*. These funds are contractually restricted by the purchase and sale agreement pending the closing of the Angola Transaction. In addition, as of December 31, 2015, approximately $3.0 million was held in collateral accounts established to pledge funds for security of obligations under the American Express Bank Pledge Agreement and the Citibank Commercial Card Agreement. As of December 31, 2015, the Angolan sales proceeds and collateral in these accounts were invested in cash, certificates of deposit, commercial paper, and money market funds, resulting in a net carrying value of approximately $253.0 million. As of December 31, 2015, the contractual maturities of these securities are within ninety days.

4. Joint Interests and Other Receivables

Joint interest and other receivables result primarily from billing shared costs under the respective operating agreements to the Company's partners. These are usually settled within 30 days of the invoice date. As of December 31, 2015 and 2014, the balance in joint interest and other receivables consisted of the following:

	December 31, 2015	December 31, 2014
	($ in thousands)	
Partners in the U.S. Gulf of Mexico	$ 50,766	$ 3,275
Accrued interest on investment securities	3,567	7,663
Other	376	2,637
	$ 54,709	$ 13,575

5. Prepaid Expenses and Other Current Assets

As of December 31, 2015 and 2014, prepaid expenses and other current assets consisted of the following:

	December 31, 2015	December 31, 2014
	($ in thousands)	
Prepaid expenses:		
Prepaid expenses(1)	$ 3,234	$ 3,842
Other current assets:		
Cash advance to joint venture partner(2)	26,869	—
Rig mobilization, regulatory and other related costs(3)	13,778	—
	$ 43,881	$ 3,842

(1) Amounts relate to the prepaid and unamortized portion of payments made for software licenses, related maintenance fees and insurance.

(2) As of December 31, 2015, the $26.9 million in other current assets relates to payments of cash calls made to our joint interest partners for drilling and completion costs.

(3) As of December 31, 2015, the $13.8 million in other current assets relates to the short-term portion of the mobilization and regulatory acceptance testing costs associated with the Rowan Reliance drilling rig.

6. Investments

The Company's investments in held-to-maturity securities, which are recorded at amortized cost which approximates fair market value, were as follows as of December 31, 2015 and December 31, 2014:

	December 31, 2015	December 31, 2014
	($ in thousands)	
Corporate securities	$ 492,955	$ 1,321,261
Commercial paper	604,986	483,534
U.S. Agency securities	—	24,996
Certificates of deposit	20,750	105,215
Total	$ 1,118,691	$ 1,935,006

The Company's condensed consolidated balance sheet included the following held-to-maturity securities:

	December 31, 2015	December 31, 2014
	($ in thousands)	
Cash and cash equivalents	$ 38,420	$ 78,753
Short-term investments	885,994	1,530,206
Restricted cash and cash equivalents	194,277	—
Long-term investments	—	326,047
	$ 1,118,691	$ 1,935,006

The contractual maturities of these held-to-maturity securities as of December 31, 2015 and December 31, 2014 were as follows:

	December 31, 2015		December 31, 2014	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
	($ in thousands)			
Within 1 year	$ 1,118,691	$ 1,118,691	$ 1,608,959	$ 1,608,959
After 1 year	—	—	326,047	326,047
	$ 1,118,691	$ 1,118,691	$ 1,935,006	$ 1,935,006

7. Fair Value Measurements

The fair values of the Company's cash and cash equivalents, joint interest and other receivables, short-term restricted funds and investments approximate their carrying amounts due to their short-term duration. The following tables summarize the Company's significant financial instruments measured on a recurring basis as categorized by the fair value measurement hierarchy:

	Level 1		Level 2		Balance as of
	Carrying Value	Fair Value(1)	Carrying Value	Fair Value(1)	December 31, 2015
			($ in thousands)		
Cash and cash equivalents:					
Cash	$ 33,173	$ 33,173	$ —	$ —	$ 33,173
Money market funds	—	—	—	—	—
Commercial paper	—	—	38,420	38,420	38,420
Subtotal	33,173	33,173	38,420	38,420	71,593
Restricted cash and cash equivalents:					
Money market funds	58,673	58,673	—	—	58,673
Commercial paper	—	—	188,517	188,517	188,517
Corporate bonds	—	—	5,010	5,010	5,010
Certificates of deposit	—	—	750	750	750
Subtotal	58,673	58,673	194,277	194,277	252,950
Short-term investments:					
U.S. Agency securities	—	—	—	—	—
Corporate bonds	—	—	487,946	487,946	487,946
Commercial paper	—	—	378,048	378,048	378,048
Certificates of deposit	—	—	20,000	20,000	20,000
Subtotal	—	—	885,994	885,994	885,994
Total	$ 91,846	$ 91,846	$ 1,118,691	$ 1,118,691	$ 1,210,537

	Level 1		Level 2		Balance as of
	Carrying Value	Fair Value(1)	Carrying Value	Fair Value(1)	December 31, 2014
			($ in thousands)		
Cash and cash equivalents:					
Cash	$ 45,733	$ 45,733	$ —	$ —	$ 45,733
Money market funds	122,218	122,218	—	—	122,218
Commercial paper	—	—	70,524	70,524	70,524
Corporate bonds	—	—	8,229	8,229	8,229
Subtotal	167,951	167,951	78,753	78,753	246,704
Short-term investments:					
U.S. Agency securities	—	—	24,996	24,996	24,996
Corporate bonds	—	—	986,985	986,985	986,985
Commercial paper	—	—	413,010	413,010	413,010
Certificates of deposit	—	—	105,215	105,215	105,215
Subtotal	—	—	1,530,206	1,530,206	1,530,206
Long-term investments:					
Corporate bonds	—	—	326,047	326,047	326,047
Subtotal	—	—	326,047	326,047	326,047
Total	$ 167,951	$ 167,951	$ 1,935,006	$ 1,935,006	$ 2,102,957

(1) As of December 31, 2015 and December 31, 2014, the Company did not record any OTTI on these assets.

8. Property, Plant, and Equipment

Property, plant, and equipment is stated at cost less accumulated depreciation/amortization and consisted of the following:

	Estimated Useful Life (Years)	December 31, 2015	December 31, 2014
		($ in thousands)	
Oil and Gas Properties:			
Proved properties:			
Well and development costs		$ 71,463	$ 183,221
Total proved properties		71,463	183,221
Unproved properties:			
Oil and gas leasehold		382,976	406,643
Less: accumulated valuation allowance		(175,963)	(208,725)
		207,013	197,918
Exploration wells in process		615,258	330,099
Total unproved properties		822,271	528,017
Total oil and gas properties, net		893,734	711,238
Other Property and Equipment:			
Computer equipment and software	3	5,350	5,214
Office equipment and furniture	3 - 5	1,349	1,329
Leasehold improvements	3 - 10	2,150	2,118
		8,849	8,661
Less: accumulated depreciation and amortization		(6,647)	(5,245)
Total other property and equipment, net		2,202	3,416
Property, plant, and equipment, net		$ 895,936	$ 714,654

The Company recorded $1.4 million, $1.7 million, and $1.3 million of depreciation and amortization expense for the years ended December 31, 2015, 2014 and 2013, respectively.

Proved Oil and Gas Properties

The Heidelberg project was formally sanctioned for development in mid-2013. As a result of the project sanction, the Company reclassified its Heidelberg exploration well costs to proved property well and development costs and these costs will be amortized when the related proved developed reserves are produced. As of December 31, 2015, prior to recognition of impairment charges, the well and development costs consisted of $104.0 million relating to well costs for the Heidelberg #1 exploration well, Heidelberg #3 appraisal well, and the Heidelberg #4 and Heidelberg #6 development wells and $221.2 million for costs associated with field development. As of December 31, 2014, the well and development costs consisted of $51.1 million relating to well costs for the Heidelberg #1 exploration well, Heidelberg #3 appraisal well, and the Heidelberg #4 and Heidelberg #6 development wells and $132.1 million for costs associated with field development.

During 2015, proved oil and gas properties with a carrying amount of $325.2 million were written down to their fair value of $68.4 million, resulting in impairment charges of $256.8 million. Significant Level 3 inputs associated with the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of future crude oil and natural gas prices, production costs, development expenditures, anticipated production of proved, probable and possible reserves, appropriate risk-adjusted discount rates and other relevant data.

8. Property, Plant, and Equipment (Continued)

Unproved Oil and Gas Properties

As of December 31, 2015 and 2014, the Company has the following unproved property acquisition costs, net of valuation allowance on the consolidated balance sheets:

	December 31, 2015	December 31, 2014
	($ in thousands)	
Individual oil and gas leaseholds with carrying value greater than $1 million	$ 305,270	$ 322,727
Individual oil and gas leaseholds with carrying value less than $1 million	77,706	83,916
	382,976	406,643
Accumulated valuation allowance	(175,963)	(208,725)
Total oil and gas leasehold	$ 207,013	$ 197,918

As of December 31, 2015 and 2014, the Company has $207.1 million and $197.9 million, respectively, net of valuation allowance, of unproved property acquisition costs relating to its U.S. Gulf of Mexico properties. In 2015, the Company paid a total consideration of $33.1 million for the acquisition of ownership interests in unproved oil and gas properties in the deepwater U.S. Gulf of Mexico. In June and July of 2014, the Company paid a total consideration of $27.8 million for the acquisition of ownership interests in unproved oil and gas properties in the deepwater U.S. Gulf of Mexico. On February 26, 2013, the Company executed a Purchase and Sale agreement (the "PSA") to sell its ownership interests on an unproved oil and gas property in Mississippi Canyon Block 209 for a total consideration of $5.6 million. The Company received $1.5 million at closing and an additional $1.5 million in September 2013 when the buyer commenced operations on the property. Pursuant to the terms and conditions of the PSA, the Company received the remaining $2.6 million that was contingent upon the purchaser’s commencement of production on this property, which occurred in 2015. For each of the years ended December 31, 2015 and 2013, the Company recognized a gain of $3.0 million on the sale of assets as a result of this transaction.

Acquisition costs of unproved properties are assessed for impairment during the holding period and transferred to proved oil and gas properties to the extent associated with successful exploration activities. Oil and gas leases for unproved properties in the U.S. Gulf of Mexico with a carrying value greater than $1.0 million are assessed individually for impairment based on the Company’s current exploration plans and an allowance for impairment is provided if impairment is indicated. Leases that are individually less than $1.0 million in carrying value or are near expiration are amortized over the terms of the leases at rates that provide for full amortization of leases upon lease expiration. These leases have expiration dates ranging from 2016 through 2024. As of December 31, 2015 and 2014, the balance for unproved properties that were subject to amortization before impairment provision was $77.7 million and $83.9 million, respectively. The Company recorded a lease impairment allowance of $26.9 million, $68.0 million and $19.4 million for the years ended December 31, 2015, 2014 and 2013, respectively.

8. Property, Plant, and Equipment (Continued)

Capitalized Exploration Well Costs

If an exploration well provides evidence as to the existence of sufficient quantities of hydrocarbons to justify evaluation for potential development, drilling costs associated with the well are initially capitalized, or suspended, pending a determination as to whether a commercially sufficient quantity of proved reserves can be attributed to the area as a result of drilling. This determination may take longer than one year in certain areas (generally, deepwater and international locations) depending upon, among other things, (i) the amount of hydrocarbons discovered, (ii) the outcome of planned geological and engineering studies, (iii) the need for additional appraisal drilling activities to determine whether the discovery is sufficient to support an economic development plan and (iv) the requirement for government sanctioning in international locations before proceeding with development activities. The following tables reflect the Company's net changes in and the cumulative costs of capitalized exploration well costs (excluding any related leasehold costs):

	December 31, 2015	December 31, 2014	December 31, 2013
		($ in thousands)	
Beginning of period	$ 330,099	$ 233,143	$ 208,274
Additions to capitalized exploration			
Exploration well costs	285,118	151,687	195,499
Capitalized interest	24,161	9,522	4,880
Reclassifications to wells, facilities, and equipment based on determination of proved reserves	—	—	(38,446)
Amounts charged to expense(1)	(24,120)	(64,253)	(137,064)
End of period	$ 615,258	$ 330,099	$ 233,143

(1) The amount of $24.1 million, $64.3 million, and $137.1 million for the years ended December 31, 2015, 2014, and 2013, respectively, represents impairment charges on exploration wells drilled in the U.S. Gulf of Mexico which did not encounter commercial hydrocarbons.

	December 31, 2015	December 31, 2014
	($ in thousands)	
Cumulative costs:		
Exploration well costs	$ 576,694	$ 315,697
Capitalized interest	38,564	14,402
	$ 615,258	$ 330,099

Well costs capitalized for a period greater than one year after completion of drilling (included in the table above) are summarized as follows:

	Year Ended December 31,		
	2015	2014	2013
		($ in thousands)	
U.S. Gulf of Mexico	$ 351,753	$ 233,141	$ 186,510
Number of projects with exploration well costs that have been capitalized more than a year	7	6	3

The above capitalized exploration well costs suspended over a year are pending ongoing evaluation including, but not limited to, results of additional appraisal drilling, well-test analysis, additional geological and geophysical data and approval of a development plan. Management believes these discoveries exhibit sufficient indications of hydrocarbons to justify potential development and is actively pursuing efforts to fully assess them. If additional information becomes available that raises substantial doubt as to the economic or operational viability of these discoveries, the associated costs will be expensed at that time.

9. Other Assets

As of December 31, 2015 and 2014, the balance in other assets consisted of the following:

	December 31, 2015	December 31, 2014
	($ in thousands)	
Debt issue cost(1)	$ 36,479	$ 36,708
Rig mobilization costs(2)	15,397	12,324
	$ 51,876	$ 49,032

(1) As of December 31, 2015, the $36.5 million in debt issue costs was related to the issuance of the Borrowing Base Facility Agreement, the Company's 2.625% convertible senior notes due 2019 and the Company's 3.125% convertible senior notes due 2024, as described in *Note 10—Long-term Debt*. As of December 31, 2014, the $36.7 million in debt issue costs included $18.5 million and $18.2 million in costs related to the issuance of the Company's 2.625% convertible senior notes due 2019 and the Company's 3.125% convertible senior notes due 2024, respectively, as described in *Note 10—Long-term Debt*. These debt issue costs are amortized over the life of the notes using the effective interest method.

(2) As of December 31, 2015 and 2014, the $15.4 million and $12.3 million, respectively, relate to costs relating to the Rowan Reliance drilling rig which was delivered in January 2015 and is currently drilling our North Platte #3 appraisal well. These costs are or will be amortized over the term of the drilling rig contracts.

10. Long-term Debt

As of December 31, 2015, the Company's long-term debt consists of the Borrowing Base Facility Agreement (the "Facility Agreement") entered into on May 29, 2015, the 2.625% convertible senior notes due 2019 issued on December 17, 2012 (the "2.625% Notes"), and the 3.125% convertible senior notes due 2024 issued on May 13, 2014 (the "3.125% Notes", and, collectively with the 2.625% Notes, the "Notes"), as follows:

Borrowing Base Facility Agreement

On May 29, 2015, Cobalt GOM #1 LLC ("GOM#1"), an indirect, wholly-owned subsidiary of the Company entered into a Borrowing Base Facility Agreement (the "Facility Agreement") with Société Générale, as administrative agent, and certain other lenders. GOM#1 is the direct owner of the oil and gas leases, wells, production facilities and other assets and agreements associated with the Company's Heidelberg development. GOM#1 does not own any of the Company's other oil and gas assets. The Facility Agreement provides for a limited recourse $150 million senior secured reserve-based term loan facility. The proceeds of the loans under the Facility Agreement will be available to fund the majority of GOM#1's share of the remaining Heidelberg field development costs, subject to the maintenance of a debt to equity ratio of the total investment in the Heidelberg development of no more than 70:30. GOM#1 may request that the commitments under the Facility Agreement be increased by up to an additional $100 million upon the satisfaction of certain conditions set forth in the Facility Agreement, and such increase is subject to lender participation. In addition, GOM#1 may request a further commitment increase by up to $400 million if GOM#1's interest in the Heidelberg field is increased, with such commitment increase subject to lender participation.

The Company is a party to the Facility Agreement and has limited funding obligations thereunder. Until completion of the Heidelberg development in accordance with the current field development plan and certain other requirements set forth in the Facility Agreement ("Completion"), the Company has guaranteed to fund cost overruns that may be incurred up to an aggregate of $38.7 million. The Company agreed to cash collateralize 50% of its funding obligation in respect of cost overruns by depositing $19.4 million in a collateral account to be established pursuant to the terms of the Facility Agreement. As of December 31, 2015 this amount has not been funded.

The amount available for borrowing at any one time under the Facility Agreement is limited to a borrowing base amount determined twice a year using agreed projections by applying the lower of (i) a project life coverage ratio of 1.5:1.0 to the sum of discounted projected net revenues from the Heidelberg field and certain capital expenditures and (ii) a loan life coverage ratio of 1.3:1.0 to the sum of discounted projected net revenues from the Heidelberg field and certain capital expenditures. Interim borrowing

10. Long-term Debt (Continued)

base redeterminations can take place between scheduled redetermination dates in limited circumstances specified in the Facility Agreement. Loans made under the Facility Agreement are scheduled to amortize in the manner set forth in the Facility Agreement commencing in July 2018 and will mature on the earlier of (a) May 29, 2020 and (b) the last day of the quarter immediately preceding the first quarter in which the aggregate remaining reserves for the Heidelberg field are projected to be less than 20% of the initial approved reserves. In addition, on or before each redetermination, GOM#1 is required to repay such amount of the loans as is required to reduce the aggregate amount of the loans to the borrowing base amount applicable on the day after such redetermination. After Completion, loans are also subject to mandatory prepayment with 33% of GOM#1's excess cash flow.

The Facility Agreement and certain related hedging obligations, if any, are secured by a first priority security interest in substantially all of the assets of GOM#1 (which are comprised only of the oil and gas leases, wells, production facilities and other assets associated with the Heidelberg development), including a mortgage on GOM#1's ownership interest in the Heidelberg field, a pledge of the equity interests of GOM#1 and a pledge of certain intercompany receivables held by the Company. All of GOM#1's revenues from the Heidelberg development will be deposited in collateral accounts established pursuant to the Facility Agreement and applied in accordance with a cash waterfall in the manner specified in the Facility Agreement. GOM#1 is required to maintain a debt service reserve account for the benefit of the lenders under the Facility Agreement, which must remain funded at all times to the level specified in the Facility Agreement.

At GOM#1's election, interest for borrowings under the Facility Agreement are determined by reference to (a) the London interbank offered rate, or LIBOR, plus an applicable margin of (i) 6.00% per annum prior to Completion and (ii) 4.00% following Completion or (b) a base rate plus an applicable margin of (i) 5.00% prior to Completion and (ii) 3.00% following Completion. Prior to Completion, GOM#1 is also required to pay a commitment fee equal to 40% of the applicable margin payable on the unused commitments under the Facility Agreement. Interest on base rate loans and the commitment fee are generally payable quarterly. Interest on LIBOR loans are generally payable at the end of the applicable interest period but no less frequently than quarterly.

The Facility Agreement contains various covenants that limit, among other things, GOM#1's ability to incur indebtedness, grant liens on its assets, merge or consolidate with other entities, sell its assets, make loans, acquisitions, capital expenditures and other investments, abandon or decommission the Heidelberg field, modify material agreements relating thereto, enter into commodity hedges and pay dividends and distributions to its parent entities.

The Facility Agreement includes customary events of default for transactions of this type, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, loan documents not being valid, defaults under project documents that are not replaced, change in control, expropriation, abandonment or decommissioning of the Heidelberg field, material title defects, the failure to pay cost overruns when due and the failure to reach Completion on or before May 29, 2018.

In addition, the Facility Agreement provides that an event of default will occur if (a) the debt to equity ratio exceeds 70:30 or (b) the then current projections show that (i) the project loan life coverage ratio in any calculation period will be 1.5:1.0 or less, (ii) the loan life coverage ratio in any calculation period will be 1.3:1.0 or less or (iii) the debt service coverage ratio in any calculation period will be 1.2:1.0 or less.

If an event of default occurs, the lenders will be able to accelerate the maturity of the Facility Agreement and exercise other rights and remedies.

As of December 31, 2015, the Company has not borrowed any amounts under the Facility Agreement.

2.625% Convertible Senior Notes due 2019

On December 17, 2012, the Company issued $1.38 billion aggregate principal amount of the 2.625% Notes. The 2.625% Notes are the Company's senior unsecured obligations and interest is payable semi-annually in arrears on June 1 and December 1 of each year. The 2.625% Notes will mature on December 1, 2019, unless earlier repurchased or converted in accordance with the terms of the 2.625% Notes. The 2.625% Notes may be converted at the option of the holder at any time prior to 5:00 p.m., New York City time, on the second scheduled trading day immediately preceding the maturity date, in multiples of $1,000 principal amount. The 2.625% Notes are convertible at an initial conversion rate of 28.023 shares of common stock per $1,000 principal amount, representing an initial conversion price of approximately $35.68 per share for a total of approximately 38.7 million underlying shares. The conversion

10. Long-term Debt (Continued)

rate is subject to adjustment upon the occurrence of certain events, as defined in the indenture governing the 2.625% Notes, but will not be adjusted for any accrued and unpaid interest except in limited circumstances. Upon conversion, the Company's conversion obligation may be satisfied, at the Company's option, in cash, shares of common stock or a combination of cash and shares of common stock.

3.125% Convertible Senior Notes due 2024

On May 13, 2014, the Company issued $1.3 billion aggregate principal amount of the 3.125% Notes. The 3.125% Notes are the Company's senior unsecured obligations and rank equal in right of payment to the 2.625% Notes. Interest on the 3.125% Notes is payable semi-annually in arrears on May 15 and November 15 of each year. The 3.125% Notes will mature on May 15, 2024, unless earlier repurchased, converted or redeemed in accordance with the terms of the Notes. Prior to November 15, 2023, the 3.125% Notes are convertible only under the following circumstances: (1) during any fiscal quarter commencing after March 31, 2015 (and only during such fiscal quarter), if the last reported sale price of the Company's common stock for at least 20 trading days (whether or not consecutive) during a 30 consecutive trading-day period ending on, and including, the last trading day of the immediately preceding fiscal quarter exceeds $30.00 on each applicable trading day; (2) during the five business-day period after any five consecutive trading-day period (the "3.125% Notes Measurement Period") in which the trading price per $1,000 principal amount of notes for each trading day of the 3.125% Notes Measurement Period was less than 98% of the product of the last reported sale price of the Company's common stock and the conversion rate on each such trading day; (3) if the Company calls all or any portion of the 3.125% Notes for redemption, at any time prior to 5:00 p.m., New York City time, on the second scheduled trading day immediately preceding the related redemption date; or (4) upon the occurrence of specified distributions or the occurrence of specified corporate events. On or after November 15, 2023, the 3.125% Notes may be converted at the option of the holder at any time prior to 5:00 p.m., New York City time, on the second scheduled trading day immediately preceding the stated maturity date, in multiples of $1,000 principal amount. As of December 31, 2015, none of the conditions allowing holders of the 3.125% Notes to convert had been met.

The 3.125% Notes are convertible at an initial conversion rate of 43.3604 shares of common stock per $1,000 principal amount, representing an initial conversion price of approximately $23.06 per share for a total of approximately 56.4 million underlying shares. The conversion rate is subject to adjustment upon the occurrence of certain events, as defined in the indenture governing the 3.125% Notes, but will not be adjusted for any accrued and unpaid interest except in limited circumstances. Upon conversion, the Company's conversion obligation may be satisfied, at the Company's option, in cash, shares of common stock or a combination of cash and shares of common stock.

Holders of the Notes who convert their Notes in connection with a "make- whole fundamental change", as defined in the indenture governing these Notes, may be entitled to a make-whole premium in the form of an increase in the conversion rate. Additionally, in the event of a fundamental change, as defined in the indenture governing the Notes, holders of the Notes may require the Company to repurchase for cash all or a portion of their Notes equal to $1,000 or a multiple of $1,000 at a fundamental change repurchase price equal to 100% of the principal amount of Notes, plus accrued and unpaid interest, if any, to, but not including, the fundamental change repurchase date.

Upon the occurrence of an Event of Default, as defined within the indenture governing the Notes, the trustee or the holders of at least 25% in aggregate principal amount of the Notes then outstanding may declare 100% of the principal of, and accrued and unpaid interest on, all the Notes to be due and payable immediately.

The Company separately accounts for the liability and equity conversion components of the Notes due to the Company's option to settle the conversion obligation in cash. The fair value of the Notes, excluding the conversion feature, at the date of issuance was calculated based on the fair value of similar non-convertible debt instruments. The resulting value of the conversion option of the Notes was recognized as a debt discount and recorded as additional paid-in capital on the Company's consolidated balance sheets. Total debt issue cost on the Notes was allocated to the liability component and to the equity component of the Notes accordingly. The debt discount and the liability component of the debt issue costs are amortized over the term of the Notes. The effective interest rate used to amortize the debt discount and the liability component of the debt issue costs were approximately 8.40% and 8.97% on the 2.625% Notes and the 3.125% Notes, respectively, based on the Company's estimated non-convertible borrowing rate as of the date the Notes were issued. Since the Company incurred losses for all periods, the impact of the conversion option would be anti-dilutive to the earnings per share and therefore was not included in the calculation.

10. Long-term Debt (Continued)

The carrying amounts of the liability components of the Notes were as follows:

	December 31, 2015			December 31, 2014		
	Principal Amount	Unamortized discount(1)	Carrying Amount	Principal Amount	Unamortized discount	Carrying Amount
	($ in thousands)					
Carrying amount of liability component						
2.625% Notes	$1,380,000	$ (242,966)	$1,137,034	$1,380,000	$ (295,509)	$1,084,491
3.125% Notes	1,300,000	(422,255)	877,745	1,300,000	(455,963)	844,037
Total	$2,680,000	$ (665,221)	$2,014,779	$2,680,000	$ (751,472)	$1,928,528

(1) Unamortized discount will be amortized over the remaining life of the Notes which is 4 years for the 2.625% Notes and 8.5 years for the 3.125% Notes.

The carrying amounts of the equity components of the Notes were as follows:

	December 31, 2015	December 31, 2014
	($ in thousands)	
Debt discount relating to value of conversion option	$ 866,340	$ 866,340
Debt issue costs	(20,185)	(20,185)
Total	$ 846,155	$ 846,155

Fair Value The fair value of the Notes, excluding the conversion feature, was calculated based on the fair value of similar non-convertible debt instruments since an observable quoted price of the Notes or a similar asset or liability is not readily available. As of December 31, 2015 and December 31, 2014, the fair values of the Notes were as follows:

	December 31, 2015	December 31, 2014
	($ in thousands)	
2.625% Notes	$ 791,209	$ 1,361,000
3.125% Notes	577,291	1,047,000
Total	$ 1,368,500	$ 2,408,000

As of December 31, 2015, the Company had $7.8 million accrued for interest on the Notes and commitment fees associated with the Facility Agreement.

Interest expense associated with the 2.625% convertible senior notes due 2019 and the 3.125% convertible senior notes due 2024 was as follows:

	For Year Ended December 31,		
	2015	2014	2013
	($ in thousands)		
Interest expense associated with accrued interest	$ 78,549	$ 61,729	$ 36,229
Interest expense associated with accretion of debt discount	86,251	68,348	44,789
Interest expense associated with amortization of debt issue costs	4,395	3,149	2,058
Less: Capitalized interest	(105,819)	(58,458)	(17,700)
	$ 63,376	$ 74,768	$ 65,376

10. Long-term Debt (Continued)

As of December 31, 2015 and December 31, 2014, the debt discounts associated with the Company's convertible senior notes resulted in the recognition of $233.6 million and $264.3 million of deferred tax liability, respectively. The Company is in an overall net deferred tax assets position with a full valuation allowance. Therefore, the Company has determined that it is more likely than not that all of the deferred tax assets will not be realized.

11. Angola Transaction

On August 22, 2015, Cobalt International Energy Angola Ltd. ("Cobalt Angola"), a wholly-owned subsidiary of the Company, executed a purchase and sale agreement (the "Purchase and Sale Agreement") with Sonangol for the sale by Cobalt Angola to Sonangol of the entire issued and outstanding share capital of CIE Angola Block 20 Ltd. and CIE Angola Block 21 Ltd., which respectively hold the Company's 40% working interest in each of Block 20 and Block 21 offshore Angola for aggregate gross consideration of $1.75 billion before Angolan withholding taxes of approximately $19.7 million (to be netted out of the gross consideration to be paid to Cobalt Angola) and certain other U.S. and Angolan taxes, expenses, and contingent liabilities. Sonangol Pesquisa e Produção, S.A., an affiliate of Sonangol, currently holds a 30% working interest in Block 20 and a 60% working interest in Block 21. The Angola Transaction is subject to Angolan government approvals.

The Purchase and Sale Agreement provides for the payment of the net consideration by Sonangol to Cobalt Angola of (i) $250 million within 7 days following the execution of the Purchase and Sale Agreement (the "First Payment"), (ii) approximately $1.28 billion within 15 days following the receipt of the Angolan government approvals (the "Second Payment"), and (iii) $200 million within the earlier of 30 days following the execution of a transfer of operations agreement, which will contain terms and conditions governing the transition of operations on each of Block 20 and Block 21 from the Company to a new operator, or one year from the execution of the Purchase and Sale Agreement (the "Third Payment"). The Purchase and Sale Agreement further provides that within 15 days following the receipt of the Angolan government approvals, Sonangol shall reimburse Cobalt Angola for its share of costs attributable to Block 20 and Block 21 for the period from January 1, 2015 through the date upon which Cobalt Angola receives the Angolan government approvals (the "Reimbursement Amount"). The obligation of Cobalt Angola to transfer the share capital of CIE Angola Block 20 Ltd. and CIE Angola Block 21 Ltd. to Sonangol and consummate the Angola Transaction is subject to the receipt by Cobalt Angola of the First Payment, the Second Payment and the Reimbursement Amount. Following completion of the transfer of the shares of CIE Angola Block 20 Ltd. and CIE Angola Block 21 Ltd., the Company shall relinquish its interest in Block 9 offshore Angola to Sonangol. If the Angolan government approvals are not received within one year from the execution date of the Purchase and Sale Agreement, the Purchase and Sale Agreement will automatically terminate and any obligations executed by the parties thereto shall be restituted in order to put such parties in their original positions as if no agreement had been executed. As a result, the First Payment has been reported as restricted cash and a liability on the balance sheet.

Pursuant to the Purchase and Sale Agreement, the Company is required to provide certain transition services to Sonangol, which may include continuing to support operations on Block 20 and 21 on a no-profit no-loss basis until Sonangol nominates a new operator or operators of such blocks, despite the fact that the Company may have already transferred the share capital of its subsidiaries holding its working interests in Blocks 20 and 21 to Sonangol.

The Company received the First Payment during the quarterly period ended September 30, 2015. The Angola Transaction is currently pending Angola government approval, and the Company therefore has not received the Second Payment, Third Payment or Reimbursement Amount.

Royalty Agreement

On February 13, 2009, the Company entered into a restated overriding royalty agreement (the "Royalty Agreement") with Whitton Petroleum Services Limited ("Whitton"). Pursuant to the terms of the Royalty Agreement, in consideration for Whitton's consulting services in connection with Blocks 9, 20 and 21 offshore Angola and the Company's business and operations in Angola, Whitton is to receive quarterly payments (measured in U.S. Dollars) equal to 2.5% of the market price of the Company's share of the crude oil produced in such quarter and not used in petroleum operations, less the cost recovery crude oil, assuming the applicable government contract is a production sharing agreement. If the applicable government contract is a risk services agreement and not a production sharing agreement (which is the case with respect to Blocks 9 and 21), pursuant to the Royalty Agreement, the Company has undertaken to agree with Whitton an economic model (the "RSA Economic Model") containing terms equivalent to those in such risk services agreement and using actual production and costs. The RSA Economic Model has not yet been agreed with Whitton. Should the Company assign all of its interest in such Blocks, Whitton may, depending on the option the Company elects, have the

11. Angola Transaction (Continued)

right to receive the market value of its rights and obligations under the Royalty Agreement, based upon the amount in cash a willing transferee of such rights and obligations would pay a willing transferor in an arm's length transaction. Given potential issues regarding how such market value of Whitton's rights and obligations under the Royalty Agreement could be calculated, including, without limitation, outstanding issues related to the RSA Economic Model, the amount of any such payment that could be owed to Whitton upon consummation of the Angola Transaction is uncertain, but may be significant. Resolution of any such payment may include an expert determination of such cash value payment. The Company can make no assurance that any results from an expert determination process will be favorable to it.

The Company's working interests in Blocks 9, 20, and 21 offshore Angola have been classified as "held for sale" on the consolidated balance sheet. The results of operations associated with Blocks 9, 20 and 21 offshore Angola have been presented as discontinued operations in the accompanying consolidated statement of operations.

The following table summarizes the assets and liabilities associated with Blocks 9, 20, and 21 offshore Angola:

	December 31, 2015	December 31, 2014(1)
	($ in thousands)	
Cash and cash equivalents	$ 8,578	$ 12,017
Joint interest and other receivables	156,599	46,399
Prepaid expenses and other current assets	8,216	10,655
Inventory	56,224	59,581
Short term restricted funds	22,538	45,062
Oil and gas properties	1,465,299	1,209,741
Other property and equipment, net	10,107	7,965
Long term restricted funds	82,568	105,051
Other assets	922	4,904
Total assets of the discontinued operation	1,811,051	1,501,375
Trade and other accounts payable	(6,089)	(7,939)
Accrued liabilities	(128,259)	(116,956)
Short term contractual obligations	(115,110)	(50,285)
Long term contractual obligations	(1,381)	(101,945)
Other long term liabilities	—	(351)
Total liabilities of the discontinued operation	$ (250,839)	$ (277,476)

(1) Amounts in the comparative period are broken out between current and long-term on the consolidated balance sheet.

Results for Blocks 9, 20, and 21 offshore Angola classified within discontinued operations consisted of the following:

	Year ended 2015	2014	2013
Seismic and exploration	$ 16,526	$ 44,136	$ 24,366
Dry hole expense and impairment(1)	153,274	103,707	126,945
General and administrative	23,603	42,770	32,652
Depreciation and amortization	2,478	2,890	546
Gain (loss) on sale of assets	—	12	3
	$ 195,881	$ 193,515	$ 184,512

(1) In light of (i) the apparent conflict between Presidential Decree No. 212/15 and the Company's rights under the Block 20 PSC and (ii) the denial of the Company's request for an extension of the declaration of commercial discovery deadline with respect to Lontra, the Company has elected to impair the value of the Lontra #1 exploration well as of December 31, 2015.

12. Stockholders' Equity

On May 13, 2014, the Company issued $1.3 billion aggregate principal amount of its 3.125% convertible senior notes due on 2024. As of December 31, 2014, $464.7 million was recorded to additional paid in capital as the equity component of the 3.125% Notes. *See also Note 10—Long-term Debt.*

13. Seismic and Exploration Expenses

Seismic and exploration expenses consisted of the following:

	For Year Ended December 31,		
	2015	2014	2013
		($ in thousands)	
Seismic costs	$ 35,054	$ 31,316	$ 43,160
Leasehold delay rentals	6,930	7,391	6,660
Drilling rig expense and other exploration expense	3,334	2,724	27
	$ 45,318	$ 41,431	$ 49,847

14. Equity based Compensation

Overview. Under the Company's Long Term Incentive Plan (the "Incentive Plan"), the Company may issue stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards and other stock-based awards to employees. At December 31, 2015, 359,989 shares remain available for grant under the Incentive Plan. Additionally, on April 30, 2015, the Company's stockholders approved the Company's 2015 Long Term Incentive Plan (the "2015 Plan"). The total number of shares of our common stock available for issuance under the 2015 Plan as of December 31, 2015 is 11,850,000. However, on January 15, 2016 the Company granted a total of 571,428 shares of restricted stock and 1,129,944 stock options to two senior officers as required pursuant to their employment agreements.

On January 28, 2010, the Company adopted the Non-Employee Directors Compensation Plan (the "NED Plan"). Under the NED Plan, the Company may issue options, restricted stock units, other stock-based award or retainers to non-employee directors. At December 31, 2015, 258,310 shares remain available for grant under the NED Plan.

The Company recognizes compensation cost for equity-based compensation to employees and non-employee directors over the period during which the recipient is required to provide service in exchange for the award, based on the fair value of the equity instrument on the date of grant, net of estimated forfeitures. If actual forfeitures differ from the Company's estimates, additional adjustments to compensation expense will be required in future periods.

Restricted Stock. For restricted stock awards with market conditions, the fair value of the awards is measured using the asset-or-nothing option pricing model. Restricted stock awards without market conditions and the performance-based awards are valued using the market price of the Company's common stock on the grant date. The Company records compensation cost, net of estimated forfeitures, for stock-based compensation awards over the requisite service period except for performance-based awards. For performance-based awards, compensation cost is recognized over the requisite service period as and when the Company determines that the achievement of the performance condition is probable, using the per-share fair value measured at grant date.

14. Equity based Compensation (Continued)

The following table summarizes the information about the restricted stock awarded to employees for years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,					
	2015		2014		2013	
	Restricted Shares	Weighted Average Grant Date Fair Value Per Share	Restricted Shares	Weighted Average Grant Date Fair Value Per Share	Restricted Shares	Weighted Average Grant Date Fair Value Per Share
Non-vested shares at beginning of year	2,802,789	$ 16.44	4,334,886	$ 14.31	4,040,825	$ 13.05
Granted	3,503,948	$ 8.53	2,275,317	$ 14.53	620,840	$ 24.58
Vested	(225,430)	$ 22.67	(1,433,172)	$ 16.32	(239,317)	$ 17.37
Forfeited or expired	(301,068)	$ 12.75	(2,374,242)	$ 10.63	(87,462)	$ 20.91
Non-vested shares at end of year	5,780,239	$ 11.59	2,802,789	$ 16.44	4,334,886	$ 14.31
Weighted-average vesting period remaining	2.14 years		3.08 years		1.22 years	
Unrecognized compensation ($ in thousands)	$ 41,028		$ 34,066		$ 22,467	

A total of 105,846 restricted stock units were granted to non-employee directors during the year ended December 31, 2015. As of December 31, 2015, the Company has granted a cumulative total of 341,645 restricted stock units to non-employee directors. For the years ended December 31, 2015, 2014 and 2013, the Company also granted 51,526, 26,438 and 15,318 shares of common stock, respectively, for annual retainers to non-employee directors who elected to be compensated by stock in lieu of cash payments. For the years ended December 31, 2015, 2014 and 2013, the weighted average fair values of these shares at grant date were $9.49, $17.52 and $25.40 per share, respectively.

Non-Qualified Stock Options. The Company grants non-qualified stock options to employees at an exercise price equal to the market value of the Company's common stock on the grant date. The non-qualified stock option awards have contractual terms of 10 years. The options granted in February 2014 and 2013 will vest 50% at the end of the third year from date of grant and 50% at the end of the fourth year from date of grant. The options granted in 2012 were fully vested during the year ended December 31, 2014.

The fair value of each stock option granted is determined using the Black-Scholes-Merton option-pricing model based on several assumptions. These assumptions are based on management's best estimate at the time of grant. The Company used the following weighted average assumptions for grants in 2015:

	2015
Expected Term in Years	5.5
Expected Volatility	54.97%
Expected Dividends	—%
Risk-Free Interest Rate	1.84%

The Company estimates expected volatility based on an analysis of its stock price since the initial public offering and comparing the stock price volatility for the period from IPO date through December 31, 2015 with the historical stock price volatility of a similar exploration and production company. The Company estimates the expected term of its option awards based on the vesting period and average remaining contractual term, referred to as the "simplified method". The Company uses this method to provide a reasonable basis for estimating its expected term based on a lack of sufficient historical employee exercise data on stock option awards.

14. Equity based Compensation (Continued)

A summary of the stock option activities for the year ended December 31, 2015 is presented below:

	Shares		Weighted Average Exercise Price	Weighted-Average Remaining Contractual Term (years)		Aggregate Intrinsic Value (thousands)
Outstanding at January 1, 2015	3,136,547	$	19.52	7.6	$	—
Granted	746,268	$	7.90			
Exercised	—	$	—		$	—
Forfeited or expired	(115,874)	$	19.33			
Outstanding at December 31, 2015	3,766,941	$	17.23	7.02	$	—
Vested or expected to vest at December 31, 2015	1,879,599	$	15.21	8.27	$	—
Exercisable at December 31, 2015	1,850,995	$	19.32	5.73	$	—

The weighted-average grant-date fair value of stock options granted during 2015 and 2014 was $4.64 and $9.12 per option, respectively, using the Black-Scholes option-pricing model. As of December 31, 2015, $8.3 million of total unrecognized compensation cost related to stock options is expected to be recognized over a weighted-average period of 1.41 years.

Restricted Stock Units. On December 3, 2010, the Company granted 198,838 restricted stock units to employees pursuant to a Restricted Stock Unit (RSU) Award Agreement. Under the RSU Award Agreement, the share-based payment was earned based on the number of successful wells drilled during the three year period ending December 31, 2013. The RSU award vested within a range of 0% to 200% of the number of RSU shares awarded on scheduled vesting dates contingent upon the recipient's continued service at each vesting date and based on the achievement of successful wells drilled as defined in the RSU Award Agreement. The recipients could not vest in an amount greater than 200% of the award or in aggregate 397,676 RSU shares. The percentage of the RSU awards vested at each of the three year periods ending December 31, 2013 was calculated by the number of successful wells drilled during the respective years multiplied by vesting percentages ranging from 25% to 37.5%. As of December 31, 2014, the RSU shares were fully vested.

A summary of the restricted stock units activities for the years ended December 31, 2015, 2014 and 2013 is presented below:

	Year Ended December 31,								
	2015			2014			2013		
	Number of shares relating Restricted Stock Units		Weighted Average Grant Date Fair Value Per Unit	Number of shares relating Restricted Stock Units		Weighted Average Grant Date Fair Value Per Unit	Number of shares relating Restricted Stock Units		Weighted Average Grant Date Fair Value Per Unit
Non-vested at beginning of year	—	$	—	21,624	$	30.50	109,275	$	30.50
Granted	—		—	—		—	—		—
Vested	—	$	—	(21,624)	$	30.50	(87,401)	$	30.50
Forfeited or expired	—		—	—		—	(250)	$	30.50
Non-vested at end of year	—		—	—		—	21,624	$	30.50
Weighted-average period remaining	—			—			—		

Stock Appreciation Rights. On February 20, 2015, the Company issued a total of 1,526,835 share appreciation rights ("SARs") under the Company's Long Term Incentive Plan (the "Plan") to the Company's officers, based on the common stock market price at the time of issuance of $8.87 per share. The SARs will vest with respect to one-third (1/3) of the underlying shares on each anniversary of the grant date over the next three years and may be settled, at the Company's discretion, by issuance of the Company's shares or by cash or by a combination of the Company's shares and cash based on the fair market value of the shares on the date of exercise. The fair value of a SAR is determined using the Black-Scholes-Merton option-pricing model which at the date of grant was $4.53 per SAR share. The Company accounts for the SAR awards as compensation cost and records a corresponding liability based on the fair value of the SARs at the end of each reporting period.

14. Equity based Compensation (Continued)

The following table summarizes the information about the stock appreciation rights awarded to employees for the year ended December 31, 2015:

	Year Ended December 31, 2015	
	Stock Appreciation Rights	Weighted Average Grant Date Fair Value Per Share
Non-vested rights at beginning of year	—	$ —
Granted	1,526,835	$ 2.74
Vested	—	$ —
Forfeited or expired	(74,503)	$ 2.74
Non-vested rights at end of year	1,452,332	$ 2.74
Weighted-average vesting period remaining	2.14 years	
Unrecognized compensation ($ in thousands)	$ 3,568	

The table below summarizes the equity-based compensation costs recognized for years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,		
	2015	2014	2013
		($ in thousands)	
Restricted stock:			
Employees	$ 18,585	$ 20,971	$ 15,470
Non-employee directors	1,493	1,476	1,260
Stock options:			
Employees	6,228	9,295	7,405
Restricted stock units (performance-based)	—	—	4,619
Stock Appreciation Rights	1,442	—	—
	$ 27,748	$ 31,742	$ 28,754

15. Employee Benefit Plan

In 2006, the Company established the Cobalt International Energy, L.P., defined contribution 401(k) plan (the "Plan"). All employees of the Company after three months of continuous employment are eligible to participate in the Plan. The plan is discretionary and provides a 6% employee contribution match as determined by the Company's Board of Directors. For the years ended December 31, 2015, 2014 and 2013, the Company recorded $1.7 million, $1.0 million, and $0.8 million, respectively, in benefits contributions to the Plan, which are included in general and administrative expenses.

16. Income Taxes

For the years ended December 31, 2015, 2014 and 2013, the Company recorded a net deferred tax asset of $896.3 million, $568.0 million, and $461.6 million, respectively with a corresponding full valuation allowance of $896.3 million, $568.0 million, and $461.6 million, respectively, for the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes.

16. Income Taxes (Continued)

The components of the income tax provision (benefit) from continuing operations are as follows:

	Year Ended December 31, 2015	2014	2013
		($ in thousands)	
Current taxes:			
U.S. federal	$ —	$ —	$ —
Foreign	—	—	—
Deferred taxes:			
U.S. federal	—	—	—
Foreign	—	—	—
Total	$ —	$ —	$ —

The reconciliation of income taxes computed at the U.S. federal statutory tax rate to the Company's income tax expense (benefit) for years ended December 31, 2015, 2014 and 2013 are as follows:

	Year Ended December 31, 2015	2014	2013
		($ in thousands)	
U.S.:			
Net income (loss) from continuing operations as reported	$ (490,190)	$ (307,024)	$ (386,169)
Less: net income (loss) from continuing operations applicable to period before corporate reorganization	—	—	—
Foreign:			
Net income (loss) from continuing operations as reported	(8,355)	(10,224)	(18,343)
Less: net income (loss) from continuing operations applicable to period before corporate reorganization	—	—	—
Net income (loss) from continuing operations applicable to period after corporate reorganization	$ (498,545)	$ (317,248)	$ (404,512)

	Year Ended December 31, 2015		2014		2013	
			($ in thousands)			
Income tax expense (benefit) at the federal statutory rate	$(174,491)	35.0%	$(111,037)	35.0%	$(141,579)	35.0%
State income taxes, net of federal income tax benefit	(804)	0.1%	(499)	0.2%	(686)	0.2%
Foreign income tax	(601)	3.3%	(3,578)	1.1%	(6,420)	1.5%
Other	1,620	-0.7%	229	-0.1%	258	0.0%
Valuation allowance	174,276	-37.7%	114,885	-36.2%	148,427	-36.7%
	$ —	—%	$ —	—%	$ —	—%

16. Income Taxes (Continued)

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. As a result of prospective application of Accounting Standards Update No. 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes, the Company offset all deferred tax liabilities and assets, as well as any related valuation allowance, and is presenting them as a single non-current amount as of December 31, 2015. The Company has not retrospectively adjusted prior periods. The significant components of the Company's deferred tax assets and liabilities were as follows:

	As of December 31,	
	2015	2014
	($ in thousands)	
Short-term deferred tax liabilities:		
2.625% convertible senior notes due 2019(1)	$ —	$ 18,479
3.125% convertible senior notes due 2024(1)	—	11,855
Total short-term deferred tax liabilities	—	30,334
Long-term deferred tax liabilities:		
2.625% convertible senior notes due 2019	$ 85,339	$ 85,471
3.125% convertible senior notes due 2024	148,279	148,507
Oil and gas properties	152,043	54,461
Total long-term deferred tax liabilities	385,661	288,439
Long-term deferred tax assets:		
Seismic and exploration costs	733,183	457,854
Stock based compensation	26,995	18,092
Domestic NOL carry forwards	568,050	415,608
Foreign NOL carry forwards	42,625	38,200
Other	(88,837)	(43,021)
Valuation allowance	(896,355)	(567,960)
Total long-term deferred assets	385,661	318,773
Net long-term deferred assets	—	30,334
Net deferred tax assets	$ —	$ —

(1) The recognition of the liability and equity components of the debt resulted in a taxable temporary basis difference and recorded as an adjustment to additional paid-in capital.

The Company has established a full valuation allowance against the deferred tax assets where the Company has determined that it is more likely than not that all of the deferred tax assets will not be realized. Because of the full valuation allowance, no income tax expense or benefit is reflected on the consolidated statement of operations for years ended December 31, 2015, 2014 and 2013.

The NOL carryforward for federal and state income tax purposes of approximately $1.6 billion and $71.8 million as of December 31, 2015 begins to expire in 2025 and 2024, respectively. The utilization of the NOL carryforwards is dependent upon generating sufficient future taxable income in the appropriate jurisdictions within the carryforward period.

As of December 31, 2015, the Company had NOL carryforward for foreign income tax purposes of approximately $83.5 million which began to expire in 2015. The Company has determined that it is more likely than not, that the foreign NOLs will not be fully realized. Therefore, a full valuation allowance was established for these net deferred tax assets.

There were no unrecognized tax benefits or accrued interest or penalties associated with unrecognized tax benefits as of December 31, 2015 and 2014.

17. Commitments

The following table summarizes by period the payments due for the Company's estimated commitments, excluding long-term debt, as of December 31, 2015:

	Payments Due By Year					
	2016	2017	2018	2019	2020	Thereafter
	($ in thousands)					
Drilling Rig and Related Contracts; midstream agreements	$ 245,726	$ 246,464	$ 26,236	$ 7,175	$ 5,907	$ 10,133
Operating Leases	2,263	2,309	2,369	2,405	2,454	3,172
Lease Rentals(1)	5,578	5,220	2,839	2,446	2,341	7,182
Total	**$ 253,567**	**$ 253,993**	**$ 31,444**	**$ 12,026**	**$ 10,702**	**$ 20,487**

(1) Relates to the annual delay rental payments payable to the Office of Natural Resources Revenue within the U.S. Department of the Interior with respect to the Company's U.S. Gulf of Mexico leases. These annual payments are required to maintain the leases from year to year.

The Company recorded $9.0 million, $9.5 million, and $8.7 million of office and delay rental expense for the years ended December 31, 2015, 2014 and 2013, respectively.

18. Contingencies

The Company is currently, and from time to time may be, subject to various lawsuits, claims and proceedings that arise in the normal course of business, including employment, commercial, environmental, safety and health matters. It is not presently possible to determine whether any such matters will have a material adverse effect on the Company's consolidated financial position, results of operations, or liquidity.

19. Other Matters

As previously disclosed, in November 2011 a formal order of investigation was issued by the SEC related to the Company's operations in Angola. In August 2014, the Company received a Wells Notice from the SEC related to this investigation. In January 2015, the Company received a termination letter from the SEC advising it that the SEC's FCPA investigation has concluded and the Staff does not intend to recommend any enforcement action by the SEC. This letter formally concluded the SEC's investigation. The Company continues to cooperate with the Department of Justice ("DOJ") with regard to its ongoing parallel investigation. The Company is unable to predict the outcome of the DOJ's ongoing investigation or any action that the DOJ may decide to pursue.

20. Selected Quarterly Financial Data—Unaudited

Unaudited quarterly financial data for the years ended December 31, 2015 and 2014 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	($ in thousands, except per share data)			
Year ended December 31, 2015				
Operating costs and expenses	$ 52,106	$ 39,604	$ 36,466	$ 314,635
Operating income (loss)	(52,106)	(39,604)	(36,466)	(314,635)
Net income (loss) from continuing operations	(70,446)	(53,369)	(49,687)	(325,043)
Basic and diluted income (loss) per common share(1) from continuing operations	$ (0.17)	$ (0.13)	$ (0.12)	$ (0.80)
Year ended December 31, 2014				
Operating costs and expenses	$ 32,052	$ 50,949	$ 45,508	$ 119,930
Operating income (loss)	(32,052)	(50,949)	(45,508)	(119,930)
Net income (loss) from continuing operations	(41,674)	(68,114)	(67,076)	(140,385)
Basic and diluted income (loss) per common share(1) from continuing operations	$ (0.10)	$ (0.17)	$ (0.16)	$ (0.34)

(1) Totals may not add due to rounding.

21. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited)

The unaudited supplemental information on oil and gas exploration activities that follows is presented in accordance with supplemental disclosure requirements under ASC No. 932, "*Extractive Activities—Oil and Gas*" ("ASC No. 932") and the Securities and Exchange Commission's final rule, *Modernization of Oil and Gas Reporting*. Disclosures include (1) capitalized costs, costs incurred and results of operations related to oil and gas producing activities, (2) net proved oil and gas reserves, and (3) a standardized measure of discounted future net cash flows relating to proved oil and gas reserves. Since the Company did not have any production activities for years ended December 31, 2015, 2014 and 2013, there will be no disclosures on results of operations related to oil and gas producing activities.

Capitalized Costs Related to Oil and Gas Activities

	Total
	($ in thousands)
As of December 31, 2015	
Unproved properties	$ 998,234
Accumulated valuation allowance	(175,963)
	822,271
Proved properties	71,463
Net capitalized costs	$ 893,734
As of December 31, 2014	
Unproved properties(1)	$ 736,742
Accumulated valuation allowance	(208,725)
	528,017
Proved properties	183,221
Net capitalized costs	$ 711,238

(1) Unproved properties include capitalized costs net of sale/like-kind exchange of leasehold interest transactions that occurred in 2014 of approximately $5.6 million for the U.S. Gulf of Mexico. No gain or loss was recognized for these transactions for the year ended December 31, 2014.

21. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited) (Continued)

Costs Incurred in Oil and Gas Activities

The following table reflects total costs incurred, both capitalized and expensed, for oil and gas property acquisition, exploration and development activities:

	Total
Year ended December 31, 2015	
Property acquisition	
Unproved	$ 35,993
Proved	—
Exploration	
Capitalized	309,428
Expensed	45,318
Development	145,021
Total Costs Incurred	$ 535,760
Year ended December 31, 2014	
Property acquisition	
Unproved	$ 27,784
Proved	—
Exploration	
Capitalized	161,208
Expensed	41,431
Development	90,642
Total Costs Incurred	$ 321,065
Year ended December 31, 2013	
Property acquisition	
Unproved	$ 37,584
Proved	—
Exploration	
Capitalized	200,379
Expensed	49,847
Development	54,133
Total Costs Incurred	$ 341,943

All of the Company's proved reserves are located in the U.S. Gulf of Mexico. Reserve quantity information for the years ended December 31, 2015, 2014 and 2013 are as follows:

	Natural Gas (in Bcf)	Natural Gas Liquids (in MMBbls)	Oil and Condensate (in MMBbls)	Equivalent Volumes (in MMBOE)
Proved undeveloped reserves:				
Balance at December 31, 2013	3.4	—	7.9	8.5
Discoveries	0.3	0.0	0.5	0.5
Balance at December 31, 2014	3.7	0.0	8.4	9.0
Revisions	(1.9)	0.3	(2.8)	(2.8)
Balance at December 31, 2015	1.8	0.3	5.6	6.2

The reserves as of December 31, 2015 presented above were prepared by the independent engineering firm, Netherland, Sewell & Associates, Inc. ("NSAI"). These reserves are located in the U.S. Gulf of Mexico. Proved oil and natural gas reserves are the estimated quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions (i.e., prices and costs) existing at the time

21. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited)

the estimate is made. Proved developed oil and natural gas reserves are proved reserves that can be expected to be recovered through existing wells and equipment in place and under operating methods being utilized at the time the estimates were made. A variety of methodologies are used to determine the Company's proved reserve estimates. The principal methodologies employed are decline curve analysis, advance production type curve matching, petrophysics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of the Company's fields. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

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

The Company follows the guidelines prescribed in ASC No. 932 for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The following summarizes the policies used in the preparation of the accompanying oil and natural gas reserve disclosures, standardized measures of discounted future net cash flows from proved oil and natural gas reserves and the reconciliations of standardized measures from year to year.

The information is based on estimates of proved reserves attributable to the Company's interest in oil and natural gas properties as of December 31, 2015, 2014 and 2013. The Company did not have proved reserves as of December 31, 2012. These estimates were prepared by NSAI.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

(1) Estimates are made of quantities of proved reserves and future periods during which they are expected to be produced based on year-end economic conditions.

(2) The estimated future cash flows are compiled by applying the twelve month average of the first of the month prices of crude oil and natural gas relating to the Company's proved reserves to the year-end quantities of those reserves for reserves.

(3) The future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on year-end economic conditions, plus Company overhead incurred.

(4) Future income tax expenses are based on year-end statutory tax rates giving effect to the remaining tax basis in the oil and natural gas properties, other deductions, credits and allowances relating to the Company's proved oil and natural gas reserves.

(5) Future net cash flows are discounted to present value by applying a discount rate of 10%.

The assumptions used to compute the standardized measure are those prescribed by the U.S. Generally Accepted Accounting Principles. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations, since these reserve quantity estimates are the basis for the valuation process. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of the Company's oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Prices used in the report prepared by NSAI are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December. For oil and NGL volumes, the average Light Louisiana Sweet spot price of $54.02 and $98.48 per barrel was used and was adjusted for quality, transportation fees, and market differentials for the years ended December 31, 2015 and 2014, respectively. For gas volumes, the average Henry Hub spot price of $2.587 and $4.350 per MMBtu was used and was adjusted for energy content, transportation fees, and a regional price differential for the years ended December 31, 2015 and 2014, respectively. For the proved reserves, the average spot prices are adjusted by energy content and

21. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited)

weighted by production over the remaining lives of the properties to determine the benchmark prices used. Such benchmark prices are \$50.78 and \$95.24 per barrel of oil, \$15.23 per barrel of NGL, and -\$0.182 and \$4.770 per Mcf of gas for the years ended December 31, 2015 and 2014, respectively. The negative average gas price is due to the application of all transportation costs for the produced wet gas to the gas price for the sales gas volume.

Information with respect to the Company's estimated discounted future net cash flows related to its proved oil and natural gas reserves as of December 31, 2015 and 2014 are as follows:

	2015	2014
	($ in thousands)	
Future cash inflows	$ 288,705	$ 814,394
Future production costs	(70,267)	(12,710)
Future development costs	(115,786)	(244,306)
Future income tax expense(1)	—	—
Future net cash flows	102,652	557,378
10% annual discount for estimated timing of cash flows	(45,077)	(192,094)
Standardized measure of discounted future net cash flows	$ 57,575	$ 365,284

(1) There is no future income tax expense as of December 31, 2015, as the tax basis of the oil and gas properties in the United States and net operating losses attributable to oil and gas operations exceed the future net revenues.

Information with respect to the Company's standardized measure of discounted future net cash flows as of December 31, 2015 and 2014 are as follows:

	2015	2014
	($ in thousands)	
Standardized measure, beginning	$ 365,284	$ 276,633
Discoveries	—	—
Revisions of previous estimates:		
Changes in prices and costs	(314,367)	(36,869)
Changes in future development costs	99,964	49,700
Changes in quantities	(122,584)	17,351
Accretion of discount	36,528	27,663
Changes in timing and other	(7,250)	30,806
Standardized measure, ending	$ 57,575	$ 365,284

22. Subsequent Events

On February 19, 2016, the Company initiated a workforce reduction program in response to the Angola Transaction and prolonged commodity price weakness, which has resulted in a reduction of the Company's capital programs and other operations. The Company expects to recognize the majority of these restructuring costs in the first and second quarters of 2016 and will recognize the remaining costs throughout 2016 until the remaining employee terminations have occurred.

Exhibit Index

Exhibit Number	Description of Document
	Certificate of Incorporation, Bylaws and Specimen Stock Certificate
3.1	Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
3.2	By-laws of the Company (incorporated by reference to Exhibit 3 to the Company's Registration Statement on Form 8-A filed December 11, 2009 (File No. 001-34579))
4.1	Specimen stock certificate (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
	Instruments relating to Debt Securities
4.2	Senior Debt Indenture, dated as of December 17, 2012 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.3	First Supplemental Indenture, dated as of December 17, 2012 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.4	Form of 2.625% Convertible Senior Note due 2019 (incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.5	Second Supplemental Indenture, dated as of May 13, 2014 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed May 13, 2014 (File No. 001-34579))
4.6	Form of 3.125% Convertible Senior Note due 2024 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed May 13, 2014 (File No. 001-34579))
	Operating Agreements
10.1	Purchase and Sale Agreement, dated August 22, 2015, by and between Cobalt International Energy Angola Ltd. and Sociedade Nacional de Combustíveis de Angola—Empresa Pública (Sonangol E.P.) (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed November 3, 2015 (File No. 001-34579))
10.2	Restated Overriding Royalty Agreement, dated February 13, 2009, by and between Whitton Petroleum Services Limited, CIE Angola Block 9 Ltd., CIE Angola Block 20 Ltd., CIE Angola Block 21 Ltd., and Cobalt International Energy, L.P. (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed November 3, 2015 (File No. 001-34579))
10.3	Borrowing Base Facility Agreement, dated May 29, 2015, by and between Cobalt GOM #1 LLC, Cobalt International Energy, Inc., Société Générale, as administrative agent, and various other lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed June 3, 2015 (File No. 001-34579))
10.4	Risk Services Agreement relating to Block 9, between CIE Angola Block 9 Ltd., Sonangol, Sonangol Pesquisa e Produção, S.A., Nazaki Oil and Gás and Alper Oil, Lda (incorporated by reference to Exhibit 10.7 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.5	Risk Services Agreement relating to Block 21, between CIE Angola Block 21 Ltd., Sonangol, Sonangol Pesquisa e Produção, S.A., Nazaki Oil and Gás and Alper Oil, Lda (incorporated by reference to Exhibit 10.8 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.6	Production Sharing Contract, dated December 20, 2011, between CIE Angola Block 20 Ltd., Sociedade Nacional de Combustíveis de Angola—Empresa Pública, Sonangol Pesquisa e Produção, S.A., BP Exploration Angola (Kwanza Benguela) Limited, and China Sonangol International Holding Limited (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.7	Exploration and Production Sharing Contract, dated December 13, 2006, between the Republic

Exhibit Number	Description of Document
	of Gabon and Total Gabon, S.A. (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.8	Assignment Agreement, dated November 29, 2007, between CIE Gabon Diaba Ltd. and Total Gabon, S.A. (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.9	Simultaneous Exchange Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference to Exhibit 10.7 to the Company's Registration Statement on Form S-1/A filed October 9, 2009 (File No. 333-161734))
10.10	Gulf of Mexico Program Management and AMI Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1/A filed October 9, 2009 (File No. 333-161734))
10.11	Offshore Daywork Drilling Contract, dated May 3, 2008, between the Partnership and Ensco Offshore Company (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.12	International Daywork Drilling Contract—Offshore, dated November 8, 2010 between CIE Angola Block 21 Ltd. and Z North Sea Ltd. (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed November 12, 2010 (File No. 001-34579)).
10.13	Offshore Drilling Contract between CIE Angola Block 21 Ltd. and Universal Energy Resources, Inc., dated July 30, 2012 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed October 30, 2012 (File No. 001-34579))
10.14	Offshore Drilling Contract between Cobalt International Energy, L.P. and Rowan Reliance Limited, dated August 5, 2013 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed October 29, 2013 (File No. 001-34579))
	Agreements with Stockholders and Directors
10.15	Amended and Restated Stockholders Agreement, dated February 21, 2013, among the Company and the stockholders that are signatory thereto (incorporated by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.16	Registration Rights Agreement, dated December 15, 2009, among the Company and the parties that are signatory thereto (incorporated by reference to Exhibit 10.31 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.17	Form of Director Indemnification Agreements (incorporated by reference to Exhibit 10.19 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
	Management Contracts/Compensatory Plans or Arrangements
10.18†	Amended and Restated Long Term Incentive Plan of the Company (incorporated by reference to Exhibit 10.15 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.19†	Form of Restricted Stock Award Agreements relating to the Class B interests (incorporated by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.20†	Form of Restricted Stock Award Agreements relating to the Class C interests (incorporated by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.21†	Form of Restricted Stock Award Agreements relating to the Class D interests (incorporated by reference to Exhibit 10.12 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.22†	Form of Non-Qualified Stock Option Award Agreement (incorporated by reference to Exhibit 10.26 to the Company's Annual Report on Form 10-K filed March 1, 2011 (File No. 001-34579)).
10.23†	Form of Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.27 to

Exhibit Number	Description of Document
	the Company’s Annual Report on Form 10-K filed March 1, 2011 (File No. 001-34579)).
10.24†	Deferred Compensation Plan of the Company (incorporated by reference to Exhibit 10.35 to the Company’s Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.25†	Annual Incentive Plan of the Company (incorporated by reference to Exhibit 10.19 to the Company’s Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.26†	Employment Agreement, dated November 12, 2009, among the Company, the Partnership and Joseph H. Bryant (incorporated by reference to Exhibit 10.1 to the Company’s Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.27†	Employment Agreement, dated October 23, 2009, among the Company, the Partnership and James H. Painter (incorporated by reference to Exhibit 10.4 to the Company’s Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.28†	Employment Agreement, dated October 23, 2009, among the Company, the Partnership and James W. Farnsworth (incorporated by reference to Exhibit 10.5 to the Company’s Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.29†	Severance Agreement, dated October 23, 2009, among the Company, the Partnership and John P. Wilkirson (incorporated by reference to Exhibit 10.6 to the Company’s Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.30†	Employment Agreement, dated September 6, 2011, between the Company and Van P. Whitfield (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K filed September 8, 2011 (File No. 001-34579))
10.31†	Severance Agreement, dated April 1, 2010, between the Company and Michael D. Drennon (incorporated by reference to Exhibit 10.30 to the Company’s Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.32†	Form of Amendment to Employment Agreements with Joseph H. Bryant, James H. Painter and James W. Farnsworth and Severance Agreements with Samuel H. Gillespie and John P. Wilkirson (incorporated by reference to Exhibit 10.3 to the Company’s Quarterly Report on Form 10-Q filed November 12, 2010 (File No. 001-34579)).
10.33†	Non-Employee Directors Compensation Plan (incorporated by reference to Exhibit 99.2 to the Company’s Current Report on Form 8-K filed January 29, 2010 (File No. 001-34579))
10.34†	Non-Employee Directors Deferral Plan (incorporated by reference to Exhibit 99.3 to the Company’s Current Report on Form 8-K filed January 29, 2010 (File No. 001-34579))
10.35†	Form of Restricted Stock Unit Award Notification under the Non- Employee Directors Compensation Plan (incorporated by reference to Exhibit 99.4 to the Company’s Current Report on Form 8-K filed January 29, 2010 (Filed No. 001-34579))
10.36†	Employment Agreement Extension, dated November 3, 2014, between the Company and Van P. Whitfield (incorporated by reference to Exhibit 10.33 to the Company's Annual Report on Form 10-K filed February 23, 2015 (File No. 001-34579))
10.37†	Employment Agreement, dated November 3, 2014, between the Company and James W. Farnsworth (incorporated by reference to Exhibit 10.34 to the Company's Annual Report on Form 10-K filed February 23, 2015 (File No. 001-34579))
10.38†	Employment Agreement, dated November 3, 2014, between the Company and James H. Painter (incorporated by reference to Exhibit 10.35 to the Company's Annual Report on Form 10-K filed February 23, 2015 (File No. 001-34579))
10.39†	Form of Special Restricted Stock Award Agreement, dated January 15, 2015 (incorporated by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K filed February 23, 2015 (File No. 001-34579))
10.40†	Form of Special Non-Qualified Stock Option Award Agreement, dated January 15, 2015 (incorporated by reference to Exhibit 10.37 to the Company's Annual Report on Form 10-K filed February 23, 2015 (File No. 001-34579))

Exhibit Number	Description of Document
10.41†	Form of Stock Appreciation Right Award Agreement under the Company's Long Term Incentive Plan (incorporated by reference to Exhibit 10.38 to the Company's Annual Report on Form 10-K filed February 23, 2015 (File No. 001-34579))
10.42†	Form of Restricted Stock Unit Award Agreement under the Company's Long Term Incentive Plan (incorporated by reference to Exhibit 10.39 to the Company's Annual Report on Form 10-K filed February 23, 2015 (File No. 001-34579))
10.43†	Form of Restricted Stock Award Agreement under the Company's Long Term Incentive Plan (incorporated by reference to Exhibit 10.40 to the Company's Annual Report on Form 10-K filed February 23, 2015 (File No. 001-34579))
10.44†	Separation Agreement, dated August 24, 2015, by and between Cobalt International Energy, Inc. and John P. Wilkirson (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed November 3, 2015 (File No. 001-34579))
10.45†	Severance Agreement, dated August 25, 2015, by and between Cobalt International Energy, Inc. and Shannon E. Young, III (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q filed November 3, 2015 (File No. 001-34579))
10.46†	Cobalt International Energy, Inc. 2015 Long Term Incentive Plan (incorporated by reference to Exhibit 99.1 to the Company's Registration Statement on Form S-8 filed May 5, 2015 (File No. 333-203877))
10.47†*	Form of Special Restricted Stock Award Agreement, dated January 15, 2016
10.48†*	Form of Special Non-Qualified Stock Option Award Agreement, dated January 15, 2016
10.49†*	Form of Restricted Stock Unit Award Agreement under the Company's 2015 Long-Term Incentive Plan
	Other Exhibits
12.1*	Statement re: Computation of Ratio of Earnings to Fixed Charges
21.1*	List of Subsidiaries
23.1*	Consent of Ernst & Young LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of the Chief Executive Officer pursuant to Rule 13a- 14(a)/15d-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of the Chief Financial Officer pursuant to Rule 13a- 14(a)/15d-14(a) of the Securities Exchange Act of 1934
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Labels Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

* Filed herewith.

** Furnished herewith.

† Management contract or compensatory plan or arrangement required to be filed as an exhibit to this Form 10-K pursuant to Item 15(b).

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CORPORATE INFORMATION

COMMON STOCK
Listed New York Stock Exchange (ticker symbol: CIE)

ANNUAL MEETING
The Annual Meeting of Shareholders will be held on Thursday, April 28, 2016.

AVAILABLE DOCUMENTS
Copies of this Annual Report on Form 10-K filed with the Securities and Exchange Commission may be obtained upon request to Investor Relations or through the company's website at www.cobaltintl.com. Quarterly reports, Corporate Governance documents and press release information may also be accessed through the website.

FORWARD LOOKING STATEMENTS
This Annual Report on Form 10-K contains estimates and forward looking statements, principally in "Business," "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations." Our estimates and forward looking statements are mainly based on our current expectations and estimates of future events and trends, which affect or may affect our businesses and operations. Although we believe that these estimates and forward looking statements are based upon reasonable assumptions, they are subject to several risks and uncertainties and are made in light of information currently available to us. Many important factors, in addition to the factors described in this Annual Report on Form 10-K, may adversely affect our results as indicated in forward looking statements.
You should read this Annual Report on Form 10-K and the documents that we have filed as exhibits hereto completely and with the understanding that our actual future results may be materially different from what we expect.

The words "believe," "may," "will," "aim," "estimate," "continue," "anticipate," "intend," "expect," "plan" and similar words are intended to identify estimates and forward looking statements. Estimates and forward looking statements speak only as of the date they were made, and, except to the extent required by law, we undertake no obligation to update or to review any estimate and/ or forward looking statement because of new information, future events or other factors. Estimates and forward looking statements involve risks and uncertainties and are not guarantees of future performance. As a result of the risks and uncertainties described in this Annual Report on Form 10-K, the estimates and forward looking statements discussed in this Annual Report on Form 10-K might not occur and our future results and our performance may differ materially from those expressed in these forward looking statements. Because of these uncertainties, you should not place undue reliance on these forward looking statements.

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