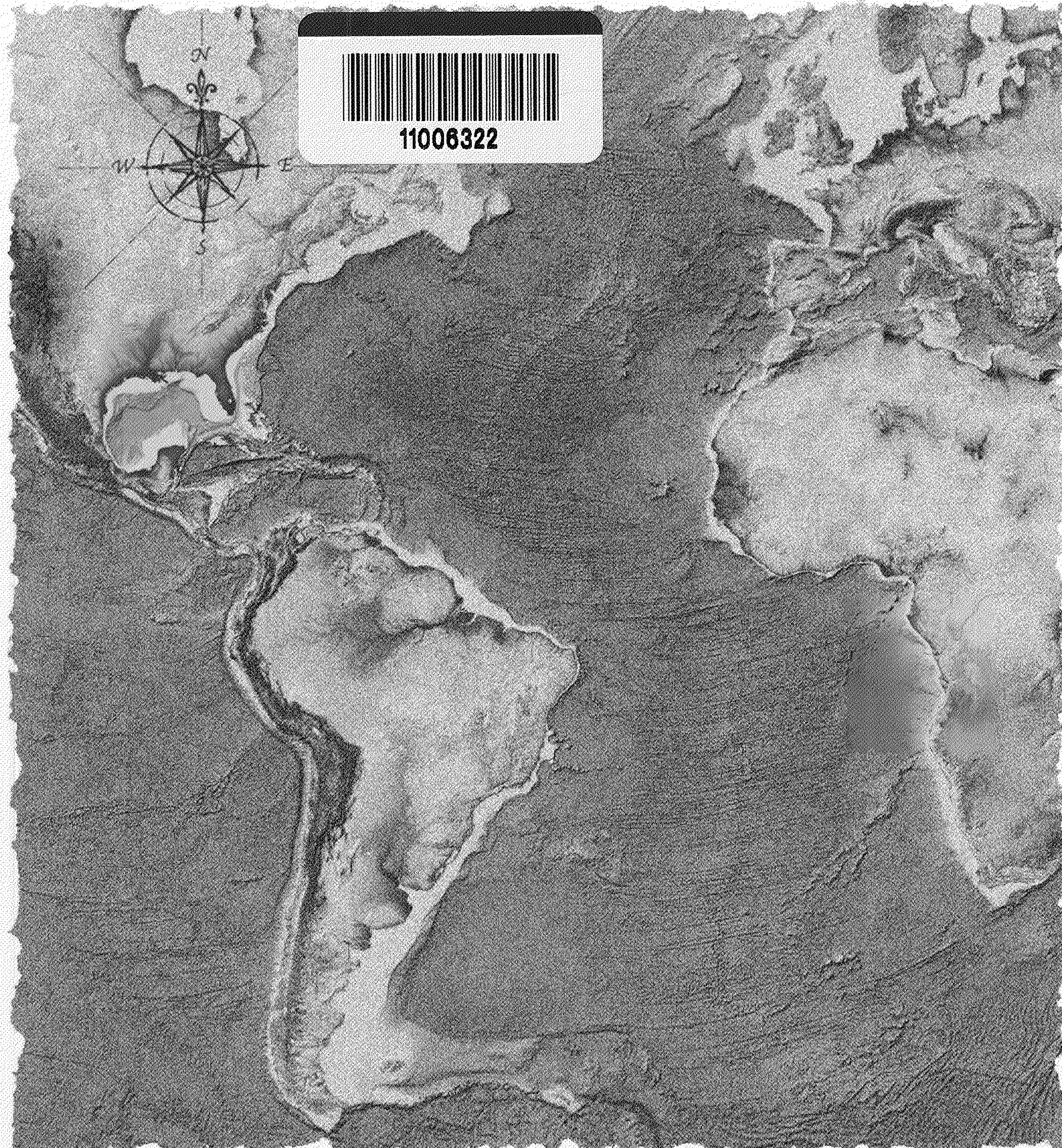
Cobalt
International Energy



2010 Annual Report on Form 10-K

Cobalt
International Energy

Dear Shareholders,

It is my honor to report numerous significant accomplishments achieved by Cobalt in our first year as a public company. As you know, we began 2010 only a few days after our initial public offering closed in December 2009. The transition from a private company to one traded publicly on the New York Stock Exchange presents its own challenges, but I am proud to report that the Cobalt team and our Board of Directors made the transition flawlessly.

In 2010, we added four outstanding directors to Cobalt's Board: Dr. Jack Golden, Dr. Myles Scoggins, Mr. John Lancaster and Mr. Jon Marshall. All of these new directors have deep global industry experience and provide the entire Board and myself invaluable counsel on a routine basis. I am extremely proud of your Board, and the world class governance that it provides.

We began 2010 with a very strong balance sheet due to the successful completion of our IPO. In addition, in early 2010 our underwriters exercised their over-allotment option which provided us with approximately $101 million of additional proceeds. As the year progressed, we utilized some of our cash to collateralize several letters of credit required in our operations. At year end 2010, our total cash, letters of credit, and TOTAL drilling promote fund totaled approximately $1.4 billion, with zero debt. Our strong balance sheet continues to provide flexibility as we grow the company.

Operationally we entered 2010 with the goal of entrenching Cobalt as a leader in two of the world's most prospective oil basins: the Gulf of Mexico and West Africa's offshore Pre-salt frontier. Our Gulf of Mexico drilling campaign set out to test several of Cobalt's exploratory prospects and appraise of one of our prior discoveries. In West Africa, our plans were to conclude our Risk Services Agreements for Angola Blocks 9 and 21 and to finalize all preparations to drill our Bicuar (formerly named Gold Dust) and Cameia (formerly named Oasis) prospects. Although events unfolded in a way that we had not anticipated in the Gulf of Mexico, I am extremely proud of how much our team accomplished in 2010 on all fronts.

Never have the benefits of portfolio diversification been more visible. When we formed Cobalt five years ago, we purposely sought to focus on at least two basins in order to mitigate our exposure to risk. Risk in our business comes in many different forms—geological, drilling, financial, and political, among others. After well over 30 years in this industry, I am humbled to say that I simply cannot predict when or where a game changing event will occur, hence the need for a diversified portfolio. For Cobalt, that is why we made the early decision to focus on two separate basins that in many ways are similar, but indeed different. The unfortunate events of April 20, 2010 proved the wisdom of this strategy.

In the Gulf of Mexico, 2010 will forever be remembered as the year of the tragic BP Horizon or the "Macondo" explosion and oil spill in the Gulf of Mexico. This one event has had a dramatic and lasting impact on so many, the most important of whom, of course, being the eleven men who lost their lives, their family members and friends, and those who were injured in the explosion. Those who live and work in the Gulf Coast communities, including the entire Gulf of Mexico oil and gas industry, were also impacted by this event, both due to the effects of the oil spill and due to the cessation of deepwater drilling operations. All of Cobalt's shareholders felt the financial impacts of this tragedy as well.

Cobalt was making preparations to commence operations on our North Platte Prospect in Garden Banks 959 when the Macondo accident occurred. In fact, just prior to spudding the well, we received notice from the federal government that it had instituted a drilling moratorium and that our operations were ordered to cease. Since that time, no deepwater drilling permits were issued by the government until February 28, 2011. In the intervening period, essentially all deepwater drilling activities were halted.

In response to Macondo, new rules and regulations have been enacted by the federal government that are intended to ensure improved drilling safety in the deepwater Gulf of Mexico. Since Macondo, the Cobalt team has worked tirelessly to meet the challenges that have arisen. Safety has always been first and foremost to all of us at Cobalt, and this incident was and is a grim reminder to our entire industry of the vital importance of safety practices in our operations. With this in mind, our staff has worked to ensure that we understand and are in full compliance with all of the new rules and regulations. While this has been an arduous process, I'm pleased to report that we recently received approval of our North Platte Exploration Plan, which is an important step in the process of obtaining drilling permit approval. While I cannot provide certainty as to when our drilling permits will be approved, I can say that this team is doing everything in its power to advance this process.

In the meantime, given the inability to drill in the Gulf of Mexico, we worked with Ensco, the owner of the new-build state-of-the-art Ensco 8503 deepwater drilling rig that Cobalt had contracted for our Gulf of Mexico drilling program, to sublet this rig in order to eliminate any financial exposure to standby costs. Our decisive action to sublet the Ensco 8503 resulted in our successfully placing the rig with another operator outside of the Gulf.

While 2010 certainly presented unforeseen challenges in the Gulf of Mexico, I'm pleased to report that our West Africa team accomplished a great deal. We opened our office in Luanda and are now a fully functioning operator in-country. We also contracted the Ocean Confidence drilling rig that will drill our first Pre-salt wells offshore Angola. We anticipate this Pre-salt drilling campaign to kick off by the end of the first half of 2011. It is important to note that Cobalt's wells will be the first wells drilled offshore Angola that specifically target the Pre-salt. I anticipate these wells to be high-impact catalysts given that all of our technical work continues to support the potential analogy between the Pre-salt in West Africa and the Pre-salt in Brazil. In addition, we acquired new 3-dimensional seismic data on both Block 9 in Angola and our Diaba Block in Gabon. Together these two projects captured over 8,000 square kilometers of new data to enhance the definition of our enormous Pre-salt portfolio.

In addition to preparing to drill our first wells offshore Angola, Cobalt participated in a Pre-salt Angolan Licensing Round in late 2010, and was conditionally awarded a license to, and indicated operator of, Block 20 offshore Angola. Cobalt's bid on Block 20 was the culmination of the technical work our West Africa team has performed over the past five years, and Block 20, when awarded, will be a great addition to our outstanding West African portfolio of assets.

I'm very pleased to report that, based on a recently completed updated assessment of Cobalt's reserves, contingent resources and prospective resources associated with Cobalt's 47 Gulf of Mexico prospects and 122 West African prospects (inclusive of Block 20) by DeGolyer & MacNaughton, our total net mean unrisked reserves and resources have increased to nearly 11 billion barrels of oil equivalent. When risked for geologic and economic uncertainties, our net mean risked resources total 2.6 billion barrels of oil equivalent. These assessments continue to reflect Cobalt's focus on finding large hydrocarbon volumes with attractive margins that are intended to create exceptional value.

During this difficult time following the Macondo accident, I have been so proud of the outstanding commitment and hard work demonstrated by our staff. Our Gulf of Mexico team continues to rise to every challenge with skill, expertise and grace during this demanding period, and our West African team continues to skillfully advance Cobalt's operational readiness as we prepare to drill our first Pre-salt well offshore Angola later this year. I have every confidence that all of this great work will deliver superior returns to our shareholders while assuring that all those involved in our operations, as well as the environments in which we work, are protected from harm.

The events of 2010 reinforced Cobalt's multi-basin business model which provides for a diversified portfolio of assets in both the deepwater Gulf of Mexico and offshore West Africa. This diversification approach has delivered the flexibility to be able to optimize the use of our capital, particularly during this period when we have been unable to drill our prospects in the deepwater Gulf of Mexico.

On behalf of the Board of Directors and all of our employees, I want to thank all of our shareholders for your continued confidence and support of Cobalt.

Joseph H. Bryant
Chairman and Chief Executive Officer

(This page has been left blank intentionally.)

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, 2010

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.)

Two Post Oak Central
1980 Post Oak Boulevard, Suite 1200
Houston, TX 77056
(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 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, 2010, 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 $552 million.

As of February 15, 2011, the registrant had 356,306,804 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement relating to the 2011 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.

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:

- our and our partners' ability to obtain permits and drill (i) in the U.S. Gulf of Mexico in light of the legislative and regulatory response resulting from the Deepwater Horizon drilling rig incident and oil spill and (ii) in West Africa;
- current and future government regulation of the oil and gas industry;
- changes in environmental laws or the implementation or interpretation of those laws;
- the costs and delays associated with complying with additional legislation and regulation of the oil and gas industry;
- the successful implementation of our and our partners' prospect development and drilling plans;
- our ability to obtain financing;
- the timing and execution of our production sharing agreement for Block 20 offshore Angola;
- uncertainties inherent in making estimates of our oil and natural gas data;
- the discovery and development of oil reserves;
- projected and targeted capital expenditures and other costs, commitments and revenues;
- termination of or intervention in concessions, licenses, permits, rights or authorizations granted by the United States, Angolan and Gabonese governments to us;
- competition;
- the volatility of oil prices;
- our ability to successfully develop our current prospects and to find, acquire or gain access to other prospects;
- the availability and cost of drilling rigs, containment resources, production equipment, supplies, personnel and oilfield services;
- the availability and cost of developing appropriate infrastructure around and transportation to our prospects;
- military operations, terrorist acts, wars or embargoes;
- our dependence on our key management personnel and our ability to attract and retain qualified personnel;
- 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; 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, oil-focused exploration and production company with a world-class below salt prospect inventory in the deepwater of the U.S. Gulf of Mexico and offshore Angola and Gabon in West Africa. Primarily through our highly targeted leasing strategy, which was the result of an in-depth, multi-year study of potential regional hydrocarbon accumulations within the deepwater U.S. Gulf of Mexico and select regions offshore West Africa, we have established a current portfolio of 132 identified, well defined prospects, comprised of 47 prospects located in the deepwater U.S. Gulf of Mexico and 85 prospects located in Blocks 9 and 21 offshore Angola and the Diaba Block offshore Gabon. In addition, on January 24, 2011 we announced that we had been conditionally awarded a 40% working interest and indicated as operator of Block 20 offshore Angola, on which we have identified 37 prospects. See "—Recent Events." All of our prospects are oil-focused.

Our prospect inventory as of December 31, 2010 is summarized in the table below:

	Identified Prospects(1)
U.S. Gulf of Mexico	
Miocene	20
Inboard Lower Tertiary(2)	22
Dual Miocene and inboard Lower Tertiary	5
U.S. Gulf of Mexico subtotal	47
West Africa	
Angola	42
Gabon	43
West Africa subtotal	85
Total Current Portfolio	132
Block 20 Offshore Angola(3)	37
Pro Forma Total Portfolio	169

(1) See "Risk Factors—We have no proved reserves and areas that we decide to drill may not yield oil in commercial quantities or quality, or at all" and "—How We Identify and Analyze Prospects."

(2) What we refer to as the inboard Lower Tertiary is an emerging trend located to the northwest of existing outboard Lower Tertiary fields such as St. Malo, Jack and Cascade. Based on the drilling results of Shenandoah #1, we believe that discoveries in the inboard Lower Tertiary will exhibit meaningfully better reservoir characteristics than had previously been encountered by the industry in the outboard Lower Tertiary.

(3) See "—Recent Events" and "Risk Factors—We will not have a license for Block 20 offshore Angola and we will not be able to commence our exploration, development and production operations on Block 20 until our Production Sharing Agreement for Block 20 is successfully negotiated and executed."

Drilling Schedule and Outlook

U.S. Gulf of Mexico. We do not know when we will be able to resume drilling operations in the U.S. Gulf of Mexico or at what cost. The uncertainty surrounding the timing and cost of our drilling activities in the U.S. Gulf of Mexico is primarily the result of (i) newly issued regulations by the Department of the Interior ("DOI") and the DOI's Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"), (ii) ongoing clarifications and interpretive guidance often in the Form of a Notice to Lessees ("NTL") issued by the DOI and the BOEMRE relating to these newly issued regulations as well as with respect to existing regulations, (iii) our continuing compliance efforts relating to these regulations, clarifications and guidance, (iv) the uncertainty as to the ability of the BOEMRE to timely review submissions and issue drilling permits, (v) the general uncertainty regarding additional regulation of the oil and gas industry's operations in the U.S. Gulf of Mexico and (vi) ongoing and potential third party legal challenges to industry drilling operations in the U.S. Gulf of Mexico.

On January 3, 2011, we received a letter from the BOEMRE describing the conditions under which we may resume our drilling operations that were suspended as a result of the Deepwater Horizon event. At the time of the BOEMRE suspension on May 27, 2010, we were running storm anchors to secure the Ocean Monarch drilling rig to spud our North Platte #1 exploratory well. We understand that twelve other operators received a similar letter. Our letter is only applicable to our North Platte #1 exploratory well that was suspended on May 27, 2010. On February 23, 2011, we received a letter from the BOEMRE notifying us of the BOEMRE's approval of the exploration plan for our North Platte #1 exploratory well. While the approval of this exploration plan is an important step in the permitting process, we will not be able to restart operations on our North Platte #1 exploratory well until we establish, to the BOEMRE's satisfaction, our compliance with NTL #10 and the BOEMRE approves our application for permit to drill. We are also awaiting responses on the various submissions we have made to the BOEMRE under applicable regulations, including the most recent version of our Oil Spill Response Plan ("OSRP") that we submitted in advance of the regular expiration of our prior OSRP in December 2010 and submissions regarding our available containment resources that we submitted upon joining the Helix Well Containment Group as required by NTL #10.

At this time, we do not know and we are unable to estimate when we will be able to restart our operations at the North Platte #1 exploratory well. In addition, even if we are able to restart our operations at the North Platte #1 exploratory well, we do not know and we are unable to estimate when we will be able to restart the remainder of our U.S. Gulf of Mexico drilling program, including our Ligurian #2 exploratory well, given that the above-mentioned January 3, 2011 and February 23, 2011 BOEMRE letters are applicable only to our North Platte #1 exploratory well. 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. See "—Impact of U.S. Gulf of Mexico Oil Spill" and "Risk Factors—The explosion and sinking of the Deepwater Horizon drilling rig in the U.S. Gulf of Mexico, the resulting oil spill and the legislative and regulatory response thereto may materially adversely impact our operations and may have significantly increased certain of the risks we face."

West Africa. We expect to commence our initial two well pre-salt exploration program on Block 21 offshore Angola, which consists of the Bicuar #1 exploratory well (formerly Gold Dust) and the Cameia #1 exploratory well (formerly Oasis), during the second quarter of 2011, depending on when the Ocean Confidence drilling rig, which we have under contract, is returned to us from an

Angolan affiliate of Total S.A. ("Total Angola") to whom we have assigned the Ocean Confidence drilling rig to drill one well and when we obtain final approval from the national oil company of Angola, Sociedade Nacional de Combustíveis de Angola—Empresa Pública ("Sonangol"), to drill. We expect to be the first company to drill a well in the deepwater offshore Angola that targets pre-salt objectives, which we believe will be geologically analogous to the pre-salt discoveries offshore Brazil. See "—Recent Events." In addition, we currently expect the initial exploratory well on the Diaba block offshore Gabon to spud in late 2012 or in 2013.

Drilling Rigs

We currently have two drilling rigs under contract: the Ensco 8503 drilling rig and the Diamond Offshore Ocean Confidence drilling rig.

Ensco 8503 Drilling Rig. The Ensco 8503 drilling rig, which we have recently accepted, has departed the U.S. Gulf of Mexico for French Guiana on an approximate five month direct sublet from its owner, Ensco Offshore Company ("Ensco"), to a subsidiary of Tullow Oil plc ("Tullow"), inclusive of mobilization and de-mobilization. We will only be obligated to pay certain amortized costs associated with certain rig upgrades during the term of the sublet. Upon return of the Ensco 8503 drilling rig to us, a special reduced base standby rate of $210,000 per day will become payable by us under the special standby rate and potential suspension agreement (the "Standby Agreement") that we executed with Ensco on November 9, 2010. This special reduced standby rate will be payable until early 2012 or, if earlier, when we are able to resume drilling operations or elect to begin the two year term of the base drilling contract. The special reduced standby rate will be paid directly from the $186 million that was placed in an escrow account established in December 2009 as a guarantee of our performance of the base drilling contract.

We entered into the base drilling contract related to the Ensco 8503 drilling rig with Ensco on May 8, 2008. This contract has a two year term, which would have commenced upon delivery and acceptance had we not entered into the Standby Agreement and which may be extended by us for one or two additional years. This two year term is not affected by the Standby Agreement or the sublet to Tullow and such term is expected to commence at the conclusion of the term of the Standby Agreement at the agreed base operating rate of $510,000 per day, subject to adjustment, which aggregates to approximately $372 million over the two years of the base contract.

We are currently seeking additional opportunities to further reduce our costs associated with the Ensco 8503 drilling rig, including using this drilling rig in our West African operations.

Ocean Confidence Drilling Rig. The Ocean Confidence drilling rig has been recently assigned to Total Angola to drill one well offshore Angola. We expect the Ocean Confidence to be returned to us in May 2011 to allow us to commence our initial two well pre-salt exploration program on Block 21 offshore Angola. Under the drilling contract we executed with an affiliate of Diamond Offshore Company on November 8, 2010, the Ocean Confidence has a base operating rate of $360,000 per day. In addition to the one-well assignment we made to Total Angola, we have the right under this contract to use the Ocean Confidence for two wells and we have an option to use it for one additional well at a base operating rate not to exceed $375,000 per day.

Prior Drilling Results

Since formation, we have drilled as operator two exploratory wells (Ligurian #1 and Criollo #1) and participated as non-operator in three exploratory wells (Heidelberg #1, Shenandoah #1 and Firefox #1) and one appraisal well (Heidelberg #2).

Heidelberg #1, Ligurian #1 and Heidelberg #2. On February 2, 2009, we announced that the Heidelberg #1 well had encountered more than 200 feet of net pay thickness in the Miocene horizons. Located in approximately 5,200 feet of water in Green Canyon 859 within the Tahiti Basin Miocene trend, this well was drilled to approximately 30,000 feet. Anadarko Petroleum Corporation ("Anadarko") operates the block and we hold a 9.375% working interest. We purchased our interest in Green Canyon 859 and 903 (the "Heidelberg blocks") from an existing owner in May 2008 after we successfully acquired 100% of the working interest in the adjacent blocks of Green Canyon 813, 814 and 858 (the "Ligurian blocks") in the 2008 Central Gulf of Mexico Lease Sale.

On July 16, 2009, we spud Ligurian #1 on Green Canyon 858 to target the upper- and middle-Miocene horizons. On October 28, 2009, we and our partners decided to temporarily cease drilling operations on Ligurian #1 having encountered operational difficulties when drilling below salt through an unforeseen geologic formation before reaching total depth or drilling to the targeted horizons. We did encounter oil in the wellbore above the targeted horizons, but believe further drilling operations will be required to adequately test the prospect.

On February 17, 2010, the Heidelberg #2 appraisal well was spud by Anadarko in approximately 5,300 feet of water in Green Canyon 903. On April 29, 2010, we announced that Anadarko notified us that Heidelberg #2 would be permanently plugged and abandoned due to mechanical problems. Heidelberg #2 did not reach the depth necessary to test any targeted objectives because of these mechanical problems. Anadarko plans to drill a substitute well on Green Canyon 903, which we refer to as Heidelberg #3. See "—Impact of U.S. Gulf of Mexico Oil Spill."

Shenandoah #1. On February 4, 2009, we announced that the Shenandoah #1 well had been drilled into Lower Tertiary horizons. Anadarko, as operator, has stated that this well encountered approximately 300 feet of net pay thickness. This well, located in approximately 5,750 feet of water in Walker Ridge 52, was drilled to approximately 30,000 feet. Anadarko operates the block and we hold a 20% working interest. We strategically purchased our interest in Shenandoah #1 to test our hypothesis that targeting the previously undrilled inboard Lower Tertiary, which we regard as an emerging trend located to the northwest of existing outboard Lower Tertiary fields such as St. Malo, Jack and Cascade, would lead to discoveries that exhibit meaningfully better reservoir characteristics than had previously been encountered by the industry in the outboard Lower Tertiary. We believe the successful results of the Shenandoah #1 well support our hypothesis.

Criollo #1. On January 29, 2010, we announced that we had reached a planned total depth of approximately 31,000 feet in the Criollo exploratory sidetrack well located in approximately 4,200 feet of water in Green Canyon 685 within the Tahiti Basin Miocene trend. The original well encountered 55 feet of net pay thickness in Miocene horizons and the sidetrack encountered 73 feet of net pay thickness in correlative reservoirs. Both the original well and the sidetrack encountered structural complexities associated with salt, which prevented the drilling of the entire target interval. We refer to the sidetrack well and the original well as the Criollo #1 exploratory well. We hold a 60% working interest in this prospect.

Firefox #1. On February 10, 2010, the Firefox #1 exploratory well was spud by BHP Billiton Petroleum (GOM) Inc. ("BHP") in approximately 4,400 feet of water in Green Canyon 817 within the Tahiti Basin Miocene trend and approximately six miles northeast of the Heidelberg discovery. On May 6, 2010, we announced that the Firefox #1 exploratory well would be plugged and abandoned, having drilled to approximately 34,000 feet. Based on the well results, we believe that undrilled potential lies below the total depth reached on the Firefox #1 exploratory well. We have named this prospect Firefox Deep. We hold a 30% working interest in this prospect.

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

Background. 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 massive oil spill. Hydrocarbons discharged continuously from the well since the time of this disaster until July 15, 2010 when a capping mechanism temporarily stopped the flow of hydrocarbons and until September 19, 2010 when efforts to permanently stop the flow of hydrocarbons from the well were successful. Although we have no economic interest in this well or the Deepwater Horizon, all of our and our partners' plans for exploration and appraisal drilling activities in the U.S. Gulf of Mexico, including our North Platte #1 exploratory well and Anadarko's Heidelberg #3 appraisal well, were suspended and continue to be significantly delayed as a result of the response by the U.S. government and its regulatory agencies to the Deepwater Horizon incident.

Increased Regulation. The U.S. government and its regulatory agencies with jurisdiction over oil and gas exploration, including the DOI and the BOEMRE, have responded to this incident by imposing moratoria on drilling operations, by requiring operators to reapply for exploration plans and drilling permits which had previously been approved and by adopting 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 drilling safety rule which sets forth increased safety measures for offshore energy development and requires, among other things, for all offshore operators to submit written certifications as to compliance with BOEMRE rules and regulations as well as the submission of independent third party written certifications as to the capabilities of certain safety devices, including blowout preventers, (ii) the workplace safety rule, which requires operators to develop and implement a 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 #6, which sets forth information requirements for exploration plans, development and production plans and development operations coordination documents in the U.S. Gulf of Mexico, including the submission of the assumptions and calculations that are used to determine the volume of the worst case discharge scenario in the event of a blowout and (iv) NTL #10, which requires that operators have written and enforceable commitments to ensure that containment resources are available in the event of a blowout, adds additional requirements to oil spill response plans and requires that operators submit written certifications regarding compliance with all regulations.

BOEMRE Permitting Process. We have been diligently working to satisfy the BOEMRE as to our compliance with all applicable laws and regulations, recognizing that we will be unable to resume operations until we can do so. We are uncertain as to how the BOEMRE will conduct its reviews to ensure our and other operators' compliance with these laws and regulations and how, when, under what circumstances and in what order the BOEMRE will issue permits or otherwise allow operations to go forward in the U.S. Gulf of Mexico. We are also uncertain as to how the BOEMRE will process the information we submitted to it in response to its January 3, 2011 letter to us in which it indicated the conditions that we needed to satisfy in order to resume our previously suspended operations on our North Platte #1 exploratory well. We believe that the extensive new and forthcoming regulations, increased regulatory scrutiny and the restructuring of the BOEMRE as successor to the Minerals Management Service will result in substantial delays to the historical timing of the permitting process.

Prior to the Deepwater Horizon incident, we had approved exploration plans for six of our prospects, including our Ligurian and North Platte prospects, and we had received the authorization for drilling permit for our North Platte #1 exploratory well and we had filed the authorization for drilling application for our Ligurian #2 exploratory well. In response to new rules and regulations from the BOEMRE following the Deepwater Horizon incident, we have submitted the new and incremental information that we are currently aware of to obtain approval to drill our Ligurian #2 and North Platte #1 exploratory wells and we are awaiting further response from the BOEMRE.

Cost Implications. Compliance with the new regulations and new interpretations of existing regulations may materially increase the cost of our drilling operations in the U.S. Gulf of Mexico. However, we are unable to estimate or quantify such costs at this time. Substantial costs associated with compliance with these regulations may adversely affect our business, financial position or future results of operations.

Strategic Relationships

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 exploratory lease inventory (which excludes the Heidelberg portion of our Ligurian/Heidelberg prospect, our Shenandoah prospect, 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, resulting in a current combined alliance portfolio covering 224 blocks. We will act as operator on behalf of the alliance through the exploration and appraisal phases of development. As part of the alliance, Total committed, among other things, to (i) provide a 5th generation deepwater rig to drill a mandatory five-well program on existing Cobalt-operated blocks, (ii) pay up to $300 million to carry a substantial share of our costs with respect to this five-well program (above the amounts Total has agreed to pay as owner of a 40% interest), (iii) pay an initial amount of approximately $280 million primarily as reimbursement of our share of historical costs in our contributed properties and consideration under purchase and sale agreements, (iv) pay 40% of the general and administrative costs relating to our operations in the U.S. Gulf of Mexico during the 10-year alliance term, and (v) award us up to $180 million based on the success of the alliance's initial five-well program, in all cases subject to certain conditions and limitations. Additionally, as part of the alliance, we formed a U.S. Gulf of Mexico-wide area of mutual interest with Total, whereby each party has the right to participate in any oil and natural gas lease interest acquired by the other party within this area. As of December 31, 2010, approximately $196 million of the $300 million that Total is obligated to carry us remains available to us, as does the potential award of up to $180 million based on the success of the alliance.

On April 22, 2009, we announced a partnership in the U.S. Gulf of Mexico with Sonangol pursuant to an agreement we had entered into with Sonangol immediately following the 2008 Central Gulf of Mexico Lease Sale, whereby Sonangol acquired a 25% non-operated interest of our pre-Total alliance interests in 11 of our U.S. Gulf of Mexico leases. The price Sonangol paid us for this interest was calculated using the price we paid for these leases plus $10 million to cover our historical seismic and exploration costs. Sonangol has since acquired a 15% non-operated interest in four additional U.S. Gulf of Mexico leases pursuant to this partnership bringing the total partnership portfolio to 15 U.S. Gulf of Mexico leases. This transaction is notable as it represents Sonangol's initial entry into the North American exploration and production sector.

Recent Events

On January 24, 2011, we announced that we had been conditionally awarded a 40% interest and had been indicated as operator of Block 20 offshore Angola. Eight companies expressed interest in obtaining a working interest in this block as part of Angola's pre-salt licensing bid round. Along with the other successful companies in this bid round, we are currently negotiating definitive agreements, most notably a Production Sharing Agreement, that will govern the exploration, development and production operations on Block 20. Our Block 20 award will not be final until the Production Sharing Agreement has been executed. Assuming we execute the Production Sharing Agreement, we expect to expend approximately $525 million for our mandatory work program and bonus payments for Block 20 over the course of the initial five year exploration period under the agreement, of which approximately $340 million is expected to be funded during the first year to cover certain social bonus payments and to establish our work program guarantees, such guarantees to be drawn against over the five year exploration period. We understand that such agreement is targeted to be finalized by the end of the second quarter of 2011. See "—Our Prospects Offshore West Africa—Block 20 Prospects" and "Risk Factors—We will not have a license for Block 20 offshore Angola and we will not be able to commence our exploration, development and production operations on Block 20 until our Production Sharing Agreement for Block 20 is successfully negotiated and executed."

How We Identify and Analyze Prospects

Our prospect identification and analysis approach is based on a thorough, basin-wide understanding of the geologic trends within our focus areas. From our inception, we have been focused on acquiring and reprocessing the highest quality seismic data available, including the application of advanced imaging technology, such as wide-azimuth seismic. This approach differs considerably from often-followed industry practice of acquiring more narrowly focused, prospect-specific data on a block-by-block basis. In the U.S. Gulf of Mexico, we have licenses covering approximately 18.3 million acres (74,000 square kilometers) of processed 3-D depth-migrated seismic data and approximately 2.8 million acres (11,400 square kilometers) of wide-azimuth 3-D depth data. In addition, we have performed proprietary reprocessing on approximately 4.3 million acres (17,600 square kilometers) of 3-D seismic data to enhance image quality and velocity model confidence. Our proprietary seismic reprocessing was performed by third-party geophysical providers using leading-edge technologies, including reverse time migration algorithms for pre-stack depth migration and 3-D surface related multiple elimination (SRME) for multiple attenuation. We also have licensed approximately 78,000 line miles (125,530 kilometers) of 2-D pre-stack depth-migrated seismic data in the U.S. Gulf of Mexico. In West Africa, we have acquired approximately 125,000 line miles (200,000 line kilometers) of 2-D seismic data and approximately 4,170 square miles (10,800 square kilometers) of 3-D seismic data. Our approach to data acquisition entails analyzing regional data, including industry well results, to understand a given trend's specific geology and defining those areas that offer the highest potential for large hydrocarbon deposits. After these areas are identified, we seek to acquire and reprocess the highest resolution subsurface 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 reservoir'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, press releases and industry intelligence, 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 our prospect identification and analysis approach, we estimate three primary characteristics:

- mean prospect area—being the mean aerial extent of a hydrocarbon-bearing rock section of a prospect (expressed in acres);
- mean "net pay" thickness—being the mean vertical extent of the effective hydrocarbon-bearing rock (expressed in feet); and
- hydrocarbon yield—being the hydrocarbons that can ultimately be recovered from a volume of rock (expressed in barrels of oil-equivalent per acre-foot).

We work with DeGolyer and MacNaughton, an independent petroleum consulting firm, in assessing our prospects. Our process culminates with a year end annual resource assessment of our prospects. We use industry recognized probabilistic methods to estimate the ranges of potential outcomes for each characteristic. The ranges are checked for reasonableness by comparison to probabilistic distributions of analogous discoveries and fields (including dry holes), which we refer to as analogs. Analogs also provide critical information regarding the age, thickness, quality of reservoir rock and components of hydrocarbon yield. As analog discoveries are appraised and become producing fields, they also provide performance data, including production and decline rates. By analyzing analogs in a basin, we refine and improve the accuracy of the estimates we calculate for prospects. For example, in evaluating our three primary characteristics in the Tahiti Basin Miocene trend, we extensively studied successful discoveries, including the Tahiti field, a subsalt Miocene field. Also, the recent Brazilian pre-salt wells have illustrated the geologic similarity of our pre-salt prospects with offshore Brazil. The Brazilian analog discoveries in conjunction with pre-salt wells in West Africa have been used to construct our estimates for mean net pay thickness (490 feet) and hydrocarbon yield for pre-salt horizons (102 barrels of oil per acre-foot) for each of our West African pre-salt prospects. We estimate a hydrocarbon yield of 183 barrels of oil per acre-foot for our West African prospects targeting Albian horizons. In the U.S. Gulf of Mexico, we estimate hydrocarbon yield for our Miocene prospects and our Lower Tertiary prospects to be 272 barrels of oil per acre-foot and 189 barrels of oil per acre-foot, respectively.

The accuracy of our estimates is subject to a number of risks and uncertainties as described under the heading "Risk Factors—We face substantial uncertainty in estimating the characteristics of our prospects, so you should not place undue reliance on any of our estimates."

The following describes how we determine the estimates of our three primary characteristics.

Prospect Area

The aerial extent of a hydrocarbon-bearing section of a prospect is referred to as "prospect area." To determine our prospect area, we use our seismic data and all available geologic data to map the aerial extent of the closures or trapping geometries that can hold hydrocarbons. Because it is not possible to directly detect the presence of hydrocarbons, we use statistical methods to define the amount of the closure that can be filled with hydrocarbons. We use a lognormal distribution to define the probabilities of the size of the prospect area. The prospect area may extend across multiple lease blocks or license areas, including on lease blocks and license areas in which we do not own an interest. For each block or license area, our ownership percentage is referred to as our working interest. For those prospects which extend beyond our leasehold acreage, we include only the portion of prospect acreage for which we hold leasehold title. We refer to this as the net mean area of the prospect. Depending on the terms of our lease or license agreement, we may be required to pay royalties on our oil and gas production.

Net Pay Thickness

The vertical extent of the effective hydrocarbon-bearing rock is referred to as "net pay" thickness. We estimate the amount of net pay thickness for a prospect by using wireline log information from wells in applicable analog fields. Our estimates for the net pay thickness of a prospect are validated with our studies of historical field thicknesses. As with our area estimations, we use a lognormal distribution to establish the probabilities of the net pay thickness of a prospect.

The expected net pay thickness of the exploratory well may differ from the mean net pay thickness of the prospect due to several factors, including the relative location of the exploratory well on the structure, potential thickness variations that may occur across the prospect and the extent to which potential reservoir horizons are penetrated.

Hydrocarbon Yield

Hydrocarbon yield is a measure of the quantity of oil and natural gas ultimately recoverable from a given volume of reservoir rock. Estimating hydrocarbon yield involves an analysis of a combination of several factors including reservoir characteristics, hydrocarbon and fluid properties and recovery efficiency. Reservoir characteristics include porosity (the ratio of the volume of voids or pore space to the total volume, in other words, the storage capacity of a reservoir rock), permeability (the measure of the ease with which fluids will flow through the pore spaces of a reservoir rock) and hydrocarbon saturation (the percentage of oil and natural gas relative to water in the pore spaces of the reservoir rock). We estimate probabilistically the ranges for these reservoir characteristics by performing a petrophysical analysis of analogous wells and reservoirs in order to determine the range of these reservoir characteristics.

Hydrocarbon and fluid properties, including the gas-oil ratio and recoverable oil per acre-foot, are estimated using published or commercially available information from offset fields to determine likely ranges expected in the prospect trend.

Recovery efficiency is estimated from modeling multiple development scenarios that consider (i) the expected initial reservoir pressure, (ii) the number of wells used for production, (iii) the type of reservoir drive mechanism, (iv) the type of secondary recovery methods (if used), and (v) the expected reservoir abandonment pressure.

How We Acquire Prospects

Once a prospect is identified and analyzed, we may seek to acquire leasehold title to the lease blocks (in the U.S. Gulf of Mexico) or license area (offshore Angola and Gabon) that include the prospect. The leasehold acquisition typically occurs from one of two sources: from governments through lease sales, licensing rounds or direct negotiations, or from other oil and gas companies through direct purchases, trades or farm-in arrangements. The leasehold acquisition provides us with title to specific blocks or license areas that we believe includes the entire prospect or a portion thereof.

Deepwater U.S. Gulf of Mexico

Our oil-focused exploration efforts primarily target subsalt Miocene and Lower Tertiary horizons in the deepwater U.S. Gulf of Mexico. The deepwater subsalt petroleum provinces are the least explored of the accessible regions of the U.S. Gulf of Mexico. Advances in technology over the past 10 years have led to significant discoveries and increased the hydrocarbon assessment in the deepwater U.S. Gulf of Mexico. These horizons 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, including Tahiti (Green Canyon 640), Knotty Head (Green Canyon 512) and Kaskida (Keathley Canyon 292).

Miocene. The subsalt Miocene trend is an established play in the deepwater U.S. Gulf of Mexico. Major discoveries in this trend include Thunder Horse, Atlantis, Tahiti, Mad Dog, Knotty Head and Heidelberg. This trend is characterized by high quality reservoirs and fluid properties, resulting in high production well rates and recovery factors. We believe the primary geologic risk in this trend is the seal capacity required to trap hydrocarbons. To address this risk, we have conducted extensive regional studies, including proprietary seismic processing, proprietary pore pressure modeling, as well as other geological and geophysical predictive techniques, to better define the seal capacity for each prospect in the trend. Based on these studies, we have identified two trends located primarily in the Green Canyon protraction area, which we refer to as the Tahiti Basin Miocene trend and the Adjacent Miocene trend. The Tahiti Basin Miocene trend is in one of the most successful hydrocarbon bearing basins within the deepwater U.S. Gulf of Mexico. Major discoveries in this area include Tahiti, Friesian, Caesar, Tonga, Knotty Head, Pony and the discovery at Heidelberg #1. Because many fields have been discovered in this area, a network of facility and pipeline infrastructure may be available for commercializing potential discoveries. The Adjacent Miocene trend is located adjacent to the Tahiti Basin Miocene trend. We believe our prospects within the Adjacent Miocene trend offer substantial, commercially viable resource potential due to similarities in the geologic profile to that of the Tahiti Basin Miocene trend. Our prospect inventory in this trend benefits from significant seismic delineation via proprietary 3-D reprocessing that indicates large, well-defined subsalt closures. In much of the trend there is limited facility and pipeline infrastructure. As such, we anticipate that free-standing, independent facilities may be required to develop discoveries in this area.

Lower Tertiary. The Lower Tertiary horizon is an older formation than the Miocene, and, as such, is generally deeper, with greater geologic complexity, than the Miocene play. These reservoirs are generally located in water depths of 5,000 feet to 8,000 feet, and have shown net pay thickness zones of up to 800 feet. In 2006, the discovery at Kaskida (Keathley Canyon 292) encountered 800 feet of net pay thickness. A more recent discovery in the Lower Tertiary, Shenandoah, has encountered approximately 300 feet of net pay thickness. Although to date there has been limited commercial production from the Lower Tertiary horizon, the industry has been successful in terms of locating and drilling large hydrocarbon-bearing structures in this horizon. 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 very similar to that of existing Miocene discoveries is the inboard Lower Tertiary trend, which includes the Shenandoah discovery. The inboard Lower Tertiary is an emerging trend located to the northwest of existing outboard Lower Tertiary fields such as St. Malo, Jack and Cascade. We were an early mover in the inboard Lower Tertiary trend, targeting specific lease blocks as early as 2006. Our technical team's hypothesis regarding the region's potentially higher-quality reservoir properties was supported by the result of the Shenandoah #1 well in which we participated. This discovery had reservoir characteristics more similar to Miocene reservoirs. We believe our inboard Lower Tertiary blocks are characterized by large, well-defined structures of a similar size to historic outboard Lower Tertiary discoveries, but are differentiated by what we believe to be potentially superior reservoir quality. Because the inboard Lower Tertiary is an emerging trend, there is limited facility and pipeline infrastructure in the area. As such, we anticipate that free-standing, independent facilities may be required to develop discoveries in this area. To date, however, the inboard Lower Tertiary trend remains largely undrilled.

U.S. Gulf of Mexico Geologic Overview

Deepwater U.S. Gulf of Mexico exploration plays rely on hydrocarbons generated from several rich oil-prone source rocks. Rivers draining the North American continent provided vast quantities of sand, silt and mud to the Gulf of Mexico through major deltas similar to the present-day Mississippi and Rio Grande deltas. Sandstone reservoirs in two main geological formations, the Miocene and Lower Tertiary horizons, were ultimately transported and deposited by gravity flows in slope minibasins and on the paleo-basin floor. Hydrocarbon seals are provided by salts and the muds integral to the depositional system.

One of the most important aspects of the deepwater U.S. Gulf of Mexico is the presence of salt. Deposited early in the basin's history, the salt is key to both the region's complexity and its longevity as an exploration province. The upward movement of salt, through the surrounding rock, formed most of the structures in the present-day deepwater U.S. Gulf of Mexico. The interaction of sediment load and salt movement partitioned the hydrocarbons into numerous moderate-size accumulations rather than just a few super-giant fields.

Much of the deepwater province is covered by a salt canopy, which has historically prevented the oil and gas industry from effectively exploring the region's potential. This region has recently garnered interest from the industry with recent advances in seismic technology, which has provided clearer imaging beneath the salt canopy. Regional geologic reconstructions postulated the presence of mature source rock, reservoir, and trapping configurations in the subsalt region, but only since the advent of 3-D depth-migrated seismic data have geoscientists been able to identify exploration prospects beneath the extensive salt canopy.

U.S. Gulf of Mexico Prospects

As of December 31, 2010, we owned working interests in 230 blocks within the deepwater U.S. Gulf of Mexico covering approximately 1.3 million gross acres (0.6 million net acres). We are the operator of approximately 75% of our U.S. Gulf of Mexico blocks. Most of our U.S. Gulf of Mexico blocks have a 10-year primary term, expiring between 2016 and 2020. 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. In the U.S. Gulf of Mexico, the royalties on our lease blocks range from 12.5% to 18.75% with an average of 15.4%.

As of December 31, 2010, we have identified the 47 prospects on our blocks that are discussed below, comprised of 20 Miocene trend prospects, 22 inboard Lower Tertiary trend prospects and 5 dual Miocene and inboard Lower Tertiary trend prospects. In interpreting this information, specific reference should be made to the subsections of this Annual Report on Form 10-K titled "Risk Factors—We face substantial uncertainties in estimating the characteristics of our prospects, so you should not place undue reliance on any of our estimates" and "Business—How We Identify and Analyze Prospects."

Miocene Prospects

Ligurian/Heidelberg. The undrilled prospect of Ligurian/Heidelberg is a 3-way structure targeting deep Miocene horizons below the Miocene reservoir discovered by the Heidelberg #1 exploratory well. We believe the Ligurian blocks and the Heidelberg blocks cover a common structure accumulation, and we therefore refer to them as a joint prospect. We are the named operator and own a 45% working interest in the Ligurian blocks, and we have a 9.375% working interest in the Anadarko-operated Heidelberg blocks. We purchased our interest in the Heidelberg blocks from an existing owner in May 2008 after we successfully acquired 100% of the working interest in the adjacent Ligurian blocks in the 2008 Central Gulf of Mexico Lease Sale. This prospect was mapped using proprietarily processed, pre-stack, depth-migrated, wide-azimuth 3-D seismic data. The undrilled Miocene horizons of this prospect have an estimated mean net area of 5,400 acres and an estimated mean net pay thickness of 200 feet. These estimates exclude the net pay encountered in certain Miocene horizons that were drilled by Heidelberg #1. For prior drilling results on Ligurian/Heidelberg, see "—Drilling Results—Heidelberg #1, Ligurian #1 and Heidelberg #2."

Ardennes. Ardennes is a 4-way prospect targeting Miocene and Lower Tertiary horizons located in Green Canyon blocks 895, 896 and 939, where we are the named operator and own a 42% working interest. This prospect was acquired through a 2007 direct purchase, a trade in 2008, and in the 2007 and 2008 Central Gulf of Mexico Lease Sales. Ardennes was mapped using our processed, pre-stack, depth-migrated, narrow-azimuth 3-D seismic data and, most recently, proprietary, pre-stack, depth-migrated, wide-azimuth 3-D seismic data. The Miocene horizons of this prospect have an estimated mean net area of 3,300 acres and an estimated mean net pay thickness of 190 feet. In addition to the Miocene horizons, the Lower Tertiary horizons of this prospect have an estimated mean net area of 3,600 acres and an estimated mean net pay thickness of 300 feet.

Rum Ramsey. Rum Ramsey is a 3-way prospect targeting Miocene horizons located in Green Canyon blocks 632, 633 and 676, where BHP is the named operator and we own a 24% working interest. This prospect was acquired in the 2008 Central Gulf of Mexico Lease Sale and through a 2008 trade. Rum Ramsey was mapped using our proprietarily processed, pre-stack, depth-migrated, narrow-azimuth 3-D seismic data and non-proprietary, pre-stack, depth-migrated, wide-azimuth 3-D seismic data. This prospect has an estimated mean net area of 4,500 acres and an estimated mean net pay thickness of 150 feet.

Lyell. Lyell is a 4-way prospect targeting Miocene horizons located in Green Canyon blocks 550 and 551, where Anadarko is the named operator and we own a 15% working interest. This prospect was acquired through a 2006 farm-in agreement and 2009 direct purchase. Lyell was mapped using non-proprietary, pre-stack, depth-migrated, wide-azimuth 3-D seismic data. This prospect has an estimated mean net area of 1,100 acres and an estimated mean net pay thickness of 230 feet.

Racer. Racer is a 3-way prospect targeting Miocene and Lower Tertiary horizons located in Green Canyon blocks 762 and 806, where BHP is the named operator and we own a 24% working interest. This prospect was acquired in the 2007 Central Gulf of Mexico Lease Sale and through a trade in 2008. Racer was mapped using our proprietarily processed, pre-stack, depth-migrated, narrow-azimuth 3-D seismic data and non-proprietary wide-azimuth 3-D depth data. The Miocene horizons of this prospect have an estimated mean net area of 4,800 acres and an estimated mean net pay thickness of 150 feet. In addition to the Miocene horizons, the Lower Tertiary horizons of this prospect have an estimated mean net area of 5,200 acres and an estimated mean net pay thickness of 300 feet.

Rocky Mountain. Rocky Mountain is a 3-way prospect targeting Miocene horizons located in Mississippi Canyon blocks 649, 693 and 737, where we are the named operator and own a 45% working interest. This prospect was acquired in the 2008 Central Gulf of Mexico Lease Sale and is syncline separated from the Blind Faith field. Rocky Mountain was mapped using our proprietarily processed, pre-stack, depth-migrated, narrow-azimuth 3-D seismic data. This prospect has an estimated mean net area of 2,400 acres and an estimated mean net pay thickness of 210 feet.

Saddelbred. Saddelbred is a 3-way prospect targeting Miocene horizons located in Green Canyon blocks 414, 457 and 458, where we are the named operator and own a 60% working interest. This prospect was acquired in the 2007 and 2010 Central Gulf of Mexico Lease Sales. Saddelbred was mapped using our proprietarily processed, wave-equation, pre-stack, depth-migrated, narrow-azimuth 3-D seismic data. This prospect has an estimated mean net area of 7,900 acres and an estimated mean net pay thickness of 140 feet.

Additional Miocene Prospects. We have 18 additional prospects targeting Miocene horizons, in which we have an average working interest of 40%. Three of these prospects are dual Miocene and Lower Tertiary prospects. These prospects are operated by either Cobalt or various other companies. Each of these additional prospects was acquired in various Gulf of Mexico Lease Sales or through direct purchases or trades. We mapped these prospects using a variety of 3-D seismic data. These prospects have an average estimated mean net area of 1,400 acres and an average estimated mean net pay thickness of 190 feet, which excludes Lower Tertiary horizons for the three dual Miocene and Lower Tertiary prospects.

Lower Tertiary Prospects

North Platte. North Platte is a 4-way prospect targeting Lower Tertiary horizons located in Garden Banks blocks 915, 958, 959, 1002 and 1003, where we are the named operator and own a 60% working interest. This prospect was acquired in the 2006 Western Gulf of Mexico Lease Sale and the 2007 and 2008 Central Gulf of Mexico Lease Sales. North Platte was mapped using our proprietarily processed, pre-stack, depth-migrated, wide-azimuth 3-D seismic data. This prospect has an estimated mean net area of 5,600 acres and an estimated mean net pay thickness of 350 feet.

Aegean. Aegean is a 3-way prospect targeting Lower Tertiary horizons located in Keathley Canyon blocks 162, 163 and 207, where we are the named operator and own a 37.5% working interest. This prospect was acquired in the 2008 Central Gulf of Mexico Lease Sale and through a 2010 trade. Aegean was mapped using proprietarily processed, pre-stack, depth-migrated, wide-azimuth 3-D seismic data. This prospect has an estimated mean net area of 6,700 acres and an estimated mean net pay thickness of 370 feet.

Shenandoah. The undrilled prospect of Shenandoah is a 3-way structure targeting Lower Tertiary horizons not penetrated by the Shenandoah #1 exploratory well. This prospect is located in Walker Ridge blocks 51 and 52, where Anadarko is the named operator and we own a 20% working interest. This prospect was acquired through a 2008 purchase. Shenandoah was mapped using non-proprietarily processed pre-stack, depth-migrated, wide-azimuth 3-D seismic data. The undrilled Lower Tertiary horizons of this prospect have an estimated mean net area of 5,700 acres and an estimated mean net pay thickness of 400 feet. These estimates exclude the net pay encountered in certain Lower Tertiary horizons that were drilled by Shenandoah #1. For prior drilling results on Shenandoah, see "—Drilling Results—Shenandoah #1."

Goodfellow (formerly Catalan). Goodfellow is a 3-way prospect targeting Lower Tertiary horizons located in Keathley Canyon block 129 and Walker Ridge blocks 89, 90 and 133, where Eni is the operator and we own a 29% working interest. This prospect was primarily acquired in the 2008 and 2009 Central Gulf of Mexico Lease Sales and in a 2009 trade. Goodfellow was mapped using our proprietarily processed, pre-stack, depth-migrated, wide-azimuth 3-D seismic data. This prospect has an estimated mean net area of 5,100 acres and an estimated mean net pay thickness of 360 feet.

Latvian. Latvian is a 3-way prospect targeting Lower Tertiary horizons located in Garden Banks blocks 874, 917, 918 and 919, where we are the named operator and own a 60% working interest. This prospect was acquired in the 2006 Western Gulf of Mexico Lease Sale and the 2007 and 2008 Central Gulf of Mexico Lease Sales. Latvian was mapped using our proprietarily processed, pre-stack, depth-migrated, wide-azimuth 3-D seismic data. This prospect has an estimated mean net area of 1,800 acres and an estimated mean net pay thickness of 300 feet.

Williams Fork. Williams Fork is a 3-way prospect targeting Lower Tertiary horizons located in Garden Banks blocks 821, 823, 865, 866 and 867, where Nexen is the named operator except for Garden Banks block 821 for which we are the operator. We have a 60% working interest in Garden Banks block 821 and a 30% working interest in the remaining blocks. This prospect was acquired in the 2006 Western Gulf of Mexico Lease Sale and the 2007 and 2008 Central Gulf of Mexico Lease Sales. Williams Fork was mapped using non-proprietarily processed, pre-stack, depth-migrated wide-azimuth 3-D seismic data. This prospect has an estimated mean net area of 5,200 acres and an estimated mean net pay thickness of 300 feet.

Caspian. Caspian is a 4-way prospect targeting Lower Tertiary horizons located in Garden Banks blocks 495, 496, 497, 539, 540 and 541, where we are the named operator and own a 60% working interest. This prospect was acquired in the 2008 Western Gulf of Mexico Lease Sale, the 2009 Central Gulf of Mexico Lease Sale and a 2009 trade. Caspian was mapped using our non-proprietarily processed, pre-stack, depth-migrated, narrow-azimuth 3-D seismic data. This prospect has an estimated mean net area of 7,200 acres and an estimated mean net pay thickness of 300 feet.

South Platte. South Platte is a 3-way prospect targeting Lower Tertiary horizons located in Garden Banks blocks 1003 and 1004 and Keathley Canyon blocks 35 and 36, where we are the named operator and own a 60% working interest. This prospect was acquired in the 2006 Western Gulf of Mexico Lease Sale, the 2008 Central Gulf of Mexico Lease Sale and through a 2009 trade. South Platte was mapped using our proprietarily processed, pre-stack, depth-migrated, wide-azimuth 3-D seismic data. This prospect has an estimated mean net area of 3,800 acres and an estimated mean net pay thickness of 300 feet.

Baffin Bay. Baffin Bay is a 3-way prospect targeting Lower Tertiary horizons located in Garden Banks blocks 956 and 957, where we are the named operator and own a 60% working interest. This prospect was acquired in the 2008 Central Gulf of Mexico Lease Sale. Baffin Bay was mapped using our proprietarily processed, pre-stack, depth-migrated, wide-azimuth 3-D seismic data. This prospect has an estimated mean net area of 4,600 acres and an estimated mean net pay thickness of 300 feet.

Additional Inboard Lower Tertiary Prospects. We have 16 additional prospects targeting inboard Lower Tertiary horizons, in which we have an average working interest of 41%. Three of these prospects are dual Miocene and Lower Tertiary prospects. These prospects are operated by either Cobalt or various other companies. Each of these additional prospects was acquired in various Gulf of Mexico Lease Sales or through trades. We mapped these prospects using a variety of 3-D seismic data. These prospects have an average estimated mean net area of 1,900 acres and an average estimated mean net pay thickness of 300 feet, which excludes Miocene horizons for the three dual Miocene and Lower Tertiary prospects.

Process for Exploration and Development of U.S. Gulf of Mexico Prospects

The initial well drilled to test a prospect is referred to as an exploratory well. If a discovery is made by the initial exploratory well, the operator may choose to drill one or more appraisal wells to delineate the size and other characteristics of the discovered field. This information is used to create a plan of development, which may include the construction of offshore facilities and drilling of development wells designed to efficiently produce hydrocarbons from the field. Any oil resources, if developed, would use either newly constructed processing facilities owned by the working-interest partnership or processing facilities leased from third-party providers. In general, we expect our development wells will be produced through subsea templates tied back to the processing facilities.

Prior to the Deepwater Horizon incident, we estimated that the average gross cost to drill and evaluate an exploratory well would be approximately $100 to $130 million for Miocene prospects and approximately $140 to $170 million for inboard Lower Tertiary prospects, that the average gross cost to drill and evaluate an appraisal well would be approximately $110 to $140 million for Miocene prospects and approximately $150 to $180 million for inboard Lower Tertiary prospects and that the average gross cost to drill and evaluate a development well would be approximately $140 to $170 million for Miocene fields and approximately $180 to $210 million for inboard Lower Tertiary fields. Compliance with the new regulations and new interpretations of existing regulations resulting from the Deepwater Horizon incident may materially increase the cost of drilling operations in the U.S. Gulf of Mexico. However, we are unable to estimate or quantify such costs at this time. Substantial costs associated with compliance with these regulations may adversely affect our business, financial position or future results of operations.

West Africa Deepwater

We have licenses with pre-salt and above salt exploration potential offshore Angola (Blocks 9 and 21) and Gabon (Diaba). We obtained our licenses offshore Angola and Gabon after a multi-year assessment of global deepwater hydrocarbon trends and resource potential. Our assessment was driven by our interpretation of seismic data, the international operating experience of our management and technical teams and an in-depth evaluation of regional political risk and economic conditions. The emerging offshore West African pre-salt exploration trend has geologic characteristics similar to the pre-salt basins offshore Brazil, which includes the Tupi and Jupiter fields in the Santos Basin and the Whale Park (Jubarte) complex in the Campos Basin. Pre-salt discoveries in West Africa have been made, both onshore and in shallow water offshore Angola and Gabon. Geologically similar fields have produced in northern Angola, Congo and southern Gabon.

Within our license areas offshore Angola (Block 9 and 21) and Gabon (Diaba), we have identified 85 prospects, with 46 having pre-salt objectives, 39 having above salt objectives. While we do not expect any discoveries offshore Angola and Gabon to include significant quantities of natural gas, we do not have contractual rights to natural gas on our blocks. We do, however, have contractual rights to natural gas from our Gabon license area.

In addition, on January 24, 2011, we announced that we had been conditionally awarded a 40% interest and had been indicated as operator of Block 20 offshore Angola, on which we have identified 37 prospects. Eight companies expressed interest in obtaining a working interest in this block as part of Angola's pre-salt licensing bid round. Along with the other successful companies in this bid round, we are currently negotiating definitive agreements, most notably a Production Sharing Agreement, that will govern the exploration, development and production operations on Block 20. Our Block 20 award will not be final until the Production Sharing Agreement has been executed. We understand that such agreement is targeted to be finalized by the end of the second quarter of 2011. See "—Our Prospects Offshore West Africa—Block 20" and "Risk Factors—We will not have a license for Block 20 offshore Angola and we will not be able to commence our exploration, development and production operations on Block 20 until our Production Sharing Agreement for Block 20 is successfully negotiated and executed."

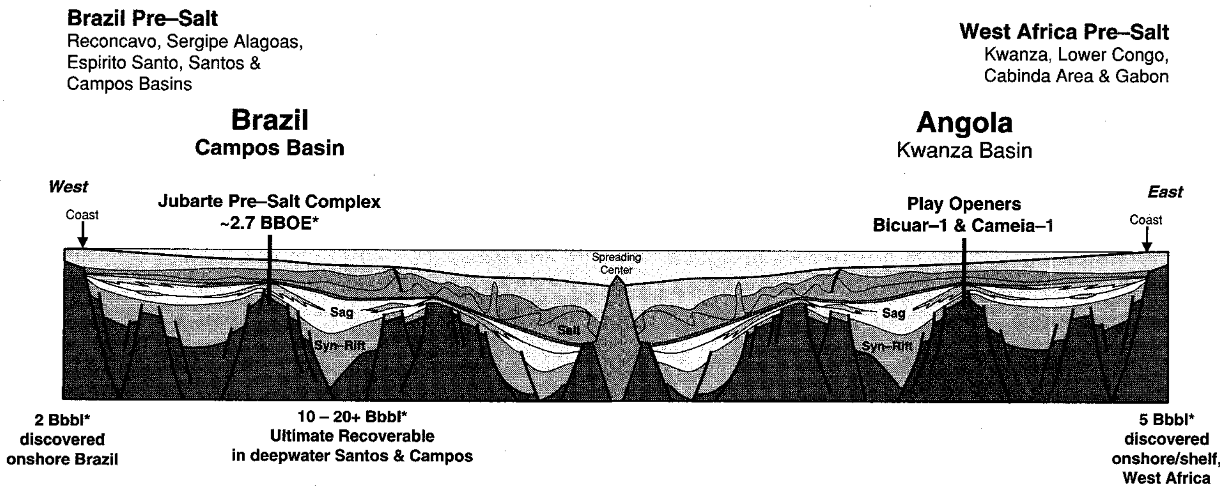
Offshore Angola, we have executed Risk Services Agreements for Blocks 9 and 21 with Sonangol, as well as Sonangol Pesquisa e Produção, S.A. ("Sonangol P & P"), Nazaki Oil and Gáz, S.A. ("Nazaki") and Alper Oil, Limitada ("Alper"). The Risk Services Agreements govern our 40% interest in and operatorship of Blocks 9 and 21 offshore Angola and form the basis of our exploration, development and production operations on these blocks. Block 9 is approximately 1 million acres (4,000 square kilometers) in size or approximately 167 U.S. Gulf of Mexico blocks 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). Block 21 is approximately 1.2 million acres (4,900 square kilometers) in size or approximately 200 U.S. Gulf of Mexico blocks. 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 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.

Offshore Gabon, we entered into an assignment agreement in February 2008 with Total Gabon and acquired a 21.25% working interest in the Diaba Block. Through the assignment we became a party to the Production Sharing Agreement between the operator Total Gabon and the Republic of Gabon. This agreement gives Cobalt the right to recover costs incurred and receive a share of the remaining profit from any commercial discoveries made on the block. The Diaba Block is approximately 2.2 million acres (9,100 square kilometers) in size. 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.

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 a direct analog to the geology offshore Brazil (Campos and Santos Basins) where recent pre-salt discoveries, such as Tupi and Jubarte, 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 Santos and Campos Basins offshore Brazil. From an exploration perspective, we believe this similarity is very meaningful, particularly in the context of recent pre-salt Brazilian discoveries. See "Item 1A. Risk Factors—We have no proved reserves and areas that we decide to drill may not yield oil in commercial quantities or quality, or at all."

Illustrative Atlantic Rift Play Symmetry(*)



* *Sources: Wood Mackenzie and IHS.* Volumes shown are of proved and probable reserves. No exploratory wells have been drilled which have targeted the pre-salt horizon in the deepwater offshore Angola and Gabon.

Recent pre-salt and shallow water discoveries offshore Brazil, coupled with the pre-salt onshore discoveries in West Africa and our ongoing analysis of seismic data, including our proprietary reprocessing of 3-D pre-stack, depth-migrated seismic data on Block 21 offshore Angola, furthers our belief that large-scale resource potential exists on our acreage. No exploratory wells have targeted the pre-salt horizon in the deepwater offshore Angola and Gabon. However, a few wells, which targeted shallower horizons in the deepwater offshore Angola, have penetrated pre-salt horizons and encountered oil, including the Baleia well on Block 20. The pre-salt reservoirs are expected to be primarily carbonates and sandstones with extensive evaporite seals and rich interbedded source rocks. The above salt (Albian) reservoirs are expected to be limestones and dolomites.

Given the evidence of large structural closures and widespread sealing salt and rich source rocks, the primary geologic risk of the deepwater West Africa plays is the presence of quality reservoirs. A discovery by Cobalt or another company of a quality pre-salt reservoir in the deepwater offshore West Africa will significantly de-risk the geologic uncertainty and increase the likelihood of geologic success of our adjacent undrilled prospects.

Our Prospects Offshore West Africa

As of December 31, 2010, within our license areas offshore Angola (Blocks 9 and 21) and Gabon (Diaba), we have identified the 85 prospects discussed below. In interpreting this information, specific reference should be made to the subsections of this Annual Report on Form 10-K titled "Risk Factors—We face substantial uncertainties in estimating the characteristics of our prospects, so you should not place undue reliance on any of our estimates" and "Business—How We Identify and Analyze Prospects."

Angola Prospects (Blocks 9 and 21)

Bicuar (formerly Gold Dust). Bicuar is a prospect targeting pre-salt horizons, where we are the named operator and have a 40% working interest. Bicuar was mapped using our pre-stack, depth-migrated 3-D seismic data. This prospect has an estimated mean net area of 21,000 acres and an estimated mean net pay thickness of 490 feet.

Cameia (formerly Oasis). Cameia is a prospect targeting pre-salt horizons, where we are the named operator and have a 40% working interest. Cameia was mapped using our pre-stack, depth-migrated 3-D seismic data. This prospect has an estimated mean net area of 25,100 acres and an estimated mean net pay thickness of 490 feet.

Silver Dollar. Silver Dollar is a prospect targeting pre-salt horizons, where we are the named operator and have a 40% working interest. Silver Dollar was mapped using our 2-D seismic data. This prospect has an estimated mean net area of 19,200 acres and an estimated mean net pay thickness of 490 feet.

Eldorado. Eldorado is a prospect targeting pre-salt horizons, where we are the named operator and have a 40% working interest. Eldorado was mapped using our 2-D seismic data. This prospect has an estimated mean net area of 16,900 acres and an estimated mean net pay thickness of 490 feet.

Monte Carlo. Monte Carlo is a prospect targeting pre-salt horizons, where we are the named operator and have a 40% working interest. Monte Carlo was mapped using our 2-D seismic data. This prospect has an estimated mean net area of 31,200 acres and an estimated mean net pay thickness of 490 feet.

Silverado. Silverado is a prospect targeting pre-salt horizons, where we are the named operator and have a 40% working interest. Silverado was mapped using our 2-D seismic data. This prospect has an estimated mean net area of 9,200 acres and an estimated mean net pay thickness of 490 feet.

Treasure Island. Treasure Island is a prospect targeting pre-salt horizons, where we are the named operator and have a 40% working interest. Treasure Island was mapped using our 2-D seismic data. This prospect has an estimated mean net area of 12,300 acres and an estimated mean net pay thickness of 490 feet.

Additional Angola Prospects (Blocks 9 and 21). We have 11 additional prospects targeting pre-salt horizons and 24 additional prospects targeting Albian horizons on Blocks 9 and 21 offshore Angola, in which we have a 40% working interest. We are the named operator for all of these prospects. We mapped all these prospects using 2-D seismic data. These prospects have an average estimated mean net area of 2,400 acres and an estimated mean net pay thickness of 410 feet.

Gabon Prospects (Diaba)

Longhorn. Longhorn is a prospect targeting pre-salt horizons, where Total Gabon is the named operator and we have a 21.25% working interest. Longhorn was mapped using our 2-D seismic data. This prospect has an estimated mean net area of 39,300 acres and an estimated mean net pay thickness of 490 feet.

Pioneer. Pioneer is a prospect targeting pre-salt horizons, where Total Gabon is the named operator and we have a 21.25% working interest. Pioneer was mapped using our 2-D seismic data. This prospect has an estimated mean net area of 35,000 acres and an estimated mean net pay thickness of 490 feet.

Rainbow. Rainbow is a prospect targeting pre-salt horizons, where Total Gabon is the named operator and we have a 21.25% working interest. Rainbow was mapped using our 2-D seismic data. This prospect has an estimated mean net area of 61,500 acres and an estimated mean net pay thickness of 490 feet.

Additional Gabon Prospects. We have 25 additional prospects targeting pre-salt horizons and 15 additional prospects targeting Albian horizons offshore Gabon, in which we have a 21.25% working interest. Total Gabon is the named operator for all of these prospects. We mapped all of these prospects using 2-D seismic data. These prospects have an average estimated mean net area of 8,400 acres and an estimated mean net pay thickness of 330 feet.

Angola Prospects (Block 20)

In addition to the 85 prospects discussed above located offshore Angola (Blocks 9 and 21) and Gabon (Diaba), we have also identified 37 prospects on Block 20 offshore Angola. See "Risk Factors—We will not have a license for Block 20 offshore Angola and we will not be able to commence our exploration, development and production operations on Block 20 until our Production Sharing Agreement for Block 20 is successfully negotiated and executed."

Lontra. Lontra is a prospect targeting pre-salt horizons, where we are indicated as operator with a 40% working interest. Lontra was mapped using our 2-D seismic data. This prospect has an estimated mean net area of 61,700 acres and an estimated mean net pay thickness of 490 feet.

Elstar. Elstar is a prospect targeting pre-salt horizons, where we are indicated as operator with a 40% working interest. Elstar was mapped using our 2-D seismic data. This prospect has an estimated mean net area of 17,400 acres and an estimated mean net pay thickness of 490 feet.

Haas. Haas is a prospect targeting pre-salt horizons, where we are indicated as operator with a 40% working interest. Haas was mapped using our 2-D seismic data. This prospect has an estimated mean net area of 12,600 acres and an estimated mean net pay thickness of 490 feet.

Additional Block 20 Prospects. We have 15 additional prospects targeting pre-salt horizons and 19 additional prospects targeting Albian horizons on Block 20, in which we have been indicated as operator with a 40% working interest. We mapped all of these prospects using 2-D seismic data. These prospects have an average estimated mean net area of 6,600 acres and an estimated mean net pay thickness of 440 feet.

Process for Exploration and Development of West Africa Prospects

In Angola, we work in a contractor relationship to the national oil company, Sonangol, with terms and conditions established by the Risk Services Agreements for Blocks 9 and 21 and we aim to work in a contractor relationship with Sonangol with terms and conditions to be established by a Production Sharing Agreement for Block 20. In Gabon, we work in a contractor relationship to the Republic of Gabon with terms and conditions established by the Production Sharing Agreement. The Production Sharing Agreements and Risk Services Agreements, as the case may be, define contractual terms, including fiscal terms, minimum contractor work, investment obligations, the carry of local partner's capital investments, and required progress milestones.

The drilling of exploratory wells in both Angola and Gabon is well within known technological boundaries. The marine and subsurface conditions are anticipated to be normally pressured thus enabling standardization and simplification of well design. Offshore Angola and Gabon, we estimate that the gross cost to drill and evaluate an exploratory well is approximately $80 to $120 million for pre-salt prospects and $30 to $50 million for above salt prospects. The timing of our initial exploratory wells included herein represents our current expectations as to the priority in which prospects will be drilled. Actual timing decisions may differ significantly due to availability of critical equipment, material and staff, drilling results from offset or nearby prospects, government approvals, and funding priorities.

As an operator in Angola, our primary development concept for any discovery will be standardized staged developments. For each discovery, we expect that an early production system incorporating a FPSO system will be implemented, to then be followed by a further standardized FPSO system depending on the size of the discovery and associated development. All FPSOs in Angola are expected to be leased.

Material Agreements

Total Alliance

On April 6, 2009, we announced that we had entered into a long-term alliance with Total. This alliance transaction principally consisted of:

- A simultaneous exchange agreement, between Total and ourselves, dated April 6, 2009 (the "Exchange Agreement"), whereby both Total and ourselves agreed to combine each company's respective U.S. Gulf of Mexico exploratory lease inventories except as to certain leases which were purchased by us and Total under separate purchase and sale agreements. This was achieved through the transfer of a 40% interest in our leases to Total in return for a 60% interest in Total's leases, and resulted in a current combined alliance portfolio covering 224 U.S. Gulf of Mexico blocks. As the Exchange Agreement contemplates the combination of Total and our U.S. Gulf of Mexico exploratory lease inventories, it excludes the Heidelberg portion of our Ligurian/Heidelberg prospect, our Shenandoah prospect, and all developed or producing properties held by Total in the U.S. Gulf of Mexico. The terms of the exchange agreement mandate the alliance, with Cobalt as operator, to drill an initial five-well program on existing Cobalt-operated blocks. This well program is expected to be drilled on the prospects of Ligurian, Criollo, North Platte, Aegean and Ardennes. In order to drill this initial program, Total committed to provide us with the use of a drilling rig to drill the well program. Furthermore, pursuant to the terms of the Exchange Agreement, Total has also committed, among other things, to (i) pay up to $300 million to carry a substantial share of costs first allocable to us based on our 60% ownership interest in the combined alliance properties with respect to this five-well program and certain other exploration and development activities (above the amounts Total has agreed to pay as owner of a 40% interests in such properties), (ii) pay an initial amount of approximately $280 million primarily as reimbursement of our share of historical costs in our contributed properties and consideration under purchase and sale agreements covering leases not included in the Exchange Agreement, and (iii) based on the success of the alliance's five-well program (primarily defined as discoveries of petroleum accumulations of at least 100 feet of net pay thickness for Miocene objectives and 250 feet of net pay thickness for Lower Tertiary objectives), pay up to $180 million to carry a substantial share of costs first allocable to Cobalt based on its 60% ownership interest in combined alliance properties with respect to additional wells and certain other exploration and development activities outside of the five-well program, in all cases subject to certain conditions and limitations. Any additional carry owed to us based on the success of the alliance's five-well program will increase the commitment by Total to pay a disproportionate share of the costs of additional wells drilled and certain other exploration and development activities incurred outside of the five-well program.
- A management and area of mutual interest agreement, between Total and ourselves, dated April 6, 2009 (the "Total AMI Agreement"), whereby both Total and ourselves agreed to participate in an area of mutual interest covering the whole U.S. Gulf of Mexico. The Total AMI Agreement is for a term of ten years, and grants each party the right and option, but not the obligation, to acquire a share of any oil and natural gas leasehold interest acquired by the other party within the designated area. The Total AMI Agreement excludes the Heidelberg portion of our Ligurian/Heidelberg prospect, our Shenandoah prospect, and all developed or producing properties held by Total in the U.S. Gulf of Mexico. For the duration of the term of the Total AMI Agreement, Total will pay 40% of the general and administrative costs relating to our operations in the U.S. Gulf of Mexico. Furthermore, this agreement designates us as the operator for all exploratory and appraisal operations. 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.

Sonangol Partnership

On May 15, 2008, we entered into a participation agreement with Sonangol, which established the terms of our U.S. Gulf of Mexico partnership with Sonangol. This partnership currently consists of an agreement for Sonangol to participate in the development of certain prospects on 15 of our U.S. Gulf of Mexico leases. In this regard, Sonangol purchased a 25% non-operated interest in the blocks containing our Sulu, Ligurian and Rocky Mountain prospects, among others. Furthermore, in connection with the partnership, Sonangol agreed to purchase their interests in our leases for the price we paid for such leases in the 2007 and 2008 Central Gulf of Mexico Lease Sales, reimburse us $10 million for our share of historical seismic and exploration costs in the subject properties and allow us to act as the operator on all of the subject properties.

Ensco Rig

We entered into a base drilling contract related to the Ensco 8503 drilling rig with Ensco on May 8, 2008. This contract has a two year term, which would have commenced upon its delivery and acceptance in February 2011 had we not entered into the Standby Agreement and which may be extended by us for one or two additional years. This two year term is not affected by the Standby Agreement and such term is expected to commence at the conclusion of the term of the Standby Agreement at the agreed base operating rate of $510,000 per day, subject to adjustment, which aggregates to approximately $372 million over the two years of the base contract. See "—Drilling Rigs—Ensco 8503 Drilling Rig."

Angolan Risk Services Agreements

On June 11, 2009, the Council of Ministers of Angola published Decree Law No. 15/09 and Decree Law No. 14/09 which granted the mining rights for the prospecting, exploration, development and production of hydrocarbons on Blocks 9 and 21 offshore Angola, respectively, to Sonangol, as the national concessionaire, and appointed Cobalt as the operator of Blocks 9 and 21, respectively. Pursuant to these Decrees Laws, in October 2009, we completed negotiations with Sonangol and initialed the finalized Risk Services Agreements for Blocks 9 and 21 offshore Angola. On December 16, 2009, the Council of Ministers of Angola approved the terms of the finalized Risk Services Agreements. On February 24, 2010, we executed Risk Services Agreements for Blocks 9 and 21 offshore Angola with Sonangol, as well as Sonangol P&P, Nazaki and Alper. Cobalt, Sonangol P&P, Nazaki and Alper comprise the "Contractor Group" under the Risk Services Agreements. The Risk Services Agreements govern our 40% interest in and operatorship of Blocks 9 and 21 offshore Angola and form the basis of our exploration, development and production operations on these blocks. Their execution is a key milestone that allows for the commencement of our offshore Angola drilling program, currently planned to begin in the second quarter of this year.

- Under the Risk Services Agreement for Block 9, in order to preserve our rights in the block, we will be required to drill three wells, as well as acquire approximately 10,764 million square feet (1,000 square kilometers) of seismic data, and find at least one commercial discovery, within four years of its signing. This four year period may be extended by one successive extension of three years if we notify Sonangol in writing of such extension at least thirty days before the end of the four year period and if we have otherwise fulfilled our obligations under the agreement. After this initial four or seven year period ends, our rights in the block are only preserved with respect to the development areas on the block on which discoveries have been made made and all other portions of the block will be forfeited. After this initial four or seven year period ends, we will also be required to commence production within four years of the date of the commercial discovery, subject to certain extensions. We have the right to a 20 year production period. In order to guarantee our exploration work obligations under the Risk Services Agreement for Block 9, we and Nazaki are required to post a financial guarantee in the amount of approximately $87.5 million. Our share of this financial guarantee is approximately $54.7 million. In March 2010, we delivered a letter of credit to Sonangol for such amount. As we complete our work obligations under the Risk Services Agreement, the amount of this letter of credit will be reduced accordingly. As is customary in Angola, we are required to make contributions for Angolan social projects and academic scholarships for Angolan citizens. We made such an initial contribution in March 2010 after the signing of the Risk Services Agreement and will make additional contributions upon each commercial discovery, upon project development sanction and each year after the commencement of production. We have a 40% working interest in Block 9, with Nazaki, Alper and Sonangol P&P holding lesser working interests in the block and sharing in the exploration, development and production costs associated with such block. Proportionate with our working interest in Block 9, we will receive 40% of a variable revenue stream that the Contractor Group will be allocated from Sonangol based on the Contractor Group's rate of return, calculated on a quarterly basis, and then reduced by applicable Angolan taxes and royalties. The Contractor Group's rate of return for each quarter will be determined by the Contractor Group's variable revenue stream from oil production less expenditures and Angolan taxes and royalties from the block. The variable revenue stream paid by Sonangol to the Contractor Group ranges from 72% to 95%, and is inversely related to the size of the applicable rate of return. The Angolan taxes and royalties applicable to the variable revenue stream include the petroleum production tax (at a current tax rate of 20% applied to the Contractor Group's variable revenue stream), the petroleum transaction tax (at a current tax rate of 70% applied to the Contractor Group's variable revenue stream less expenditures less the Contractor Group's specified production allowance, which ranges from 55% to 95% of the Contractor Group's variable revenue stream depending inversely on the Contractor Group's rate of return) and the petroleum income tax (at a current tax rate of 65.75% applied to the Contractor Group's variable revenue stream less expenditures and less petroleum production and petroleum transaction taxes paid).

- Under the Risk Services Agreement for Block 21, in order to preserve our rights in the block, we will be required to drill four wells and find at least one commercial discovery, within five years of its signing. This five year period may be extended by one successive extension of three years if we notify Sonangol in writing of such extension at least thirty days before the end of the five year period and if we have otherwise fulfilled our obligations under the agreement. After this initial five or eight year period ends, our rights in the block are only preserved with respect to the development areas on the block on which discoveries have been made made and all other portions of the block will be forfeited. After this initial five or eight year period ends, we will also be required to commence production within four years of the date of the commercial discovery, subject to certain extensions. We have the right to a 25 year production period. In order to guarantee these exploration work obligations under the Risk Services Agreement for Block 21, we and Nazaki are required to post a financial guarantee in the amount approximately $147.5 million. Our share of this financial guarantee is approximately $92.2 million. In March 2010, we delivered a letter of credit to Sonangol for such amount. As we complete our work obligations under the Risk Services Agreement, the amount of this letter of credit will be reduced accordingly. As is customary in Angola, we are required to make contributions for Angolan social projects and academic scholarships for Angolan citizens. We made such an initial contribution in March 2010 after the signing of the Risk Services Agreement and will make additional contributions upon each commercial discovery, upon project development sanction and each year after the commencement of production. We have a 40% working interest in Block 21, with Nazaki, Alper and Sonangol P&P holding lesser working interests in the block and sharing in the exploration, development and production costs associated with such block. Proportionate with our working interest in Block 21, we will receive 40% of a variable revenue stream that the Contractor Group will be allocated from Sonangol based on the Contractor Group's rate of return, calculated on a quarterly basis, and then reduced by applicable Angolan taxes and royalties. The Contractor Group's rate of return for each quarter will be determined by the Contractor Group's variable revenue stream from oil production less expenditures and Angolan taxes and royalties from the block. The variable revenue stream paid by Sonangol to the Contractor Group ranges from 60% to 96%, and is inversely related to the size of the applicable rate of return. The Angolan taxes and royalties applicable to the variable revenue stream include the petroleum production tax (at a current tax rate of 20% applied to the Contractor Group's variable revenue stream), the petroleum transaction tax (at a current tax rate of 70% applied to the Contractor Group's variable revenue stream less expenditures less the Contractor Group's specified production allowance, which ranges from 35% to 90% of the Contractor Group's variable revenue stream depending inversely on the Contractor Group's rate of return) and the petroleum income tax (at a current tax rate of 65.75% applied to the Contractor Group's variable revenue stream less expenditures and less petroleum production and petroleum transaction taxes paid).

Competition

The oil and gas industry is highly competitive. We encounter strong competition from other independent and major 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 able to pay more for desirable oil and gas properties, or to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources will 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.

We are also affected by competition for drilling rigs and the availability of related equipment. To the extent that in the future we acquire and develop undeveloped properties, higher commodity prices generally increase the demand for drilling rigs, supplies, services, equipment and crews, and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Over the past three years, oil and gas companies have experienced higher drilling and operating costs. Shortages of, or increasing costs for, experienced drilling crews and equipment and services could restrict our ability to drill wells and conduct our operations.

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 further acquisitions.

Title to Property

We believe that we have satisfactory title to our prospect interests in accordance with standards generally accepted in the oil and gas industry. In West Africa, we currently have a license on the Diaba Block offshore Gabon, and licenses for Blocks 9 and 21 offshore Angola. We also have contractual rights with respect to and have been publicly awarded a 40% interest and indicated as operator of Block 20 offshore Angola. We are currently negotiating a Production Sharing Agreement that will govern the exploration, development and production operations on Block 20 and our Block 20 award and license will not be final until the Production Sharing Agreement has been executed. See "Risk Factors—We will not have a license for Block 20 offshore Angola and we will not be able to commence our exploration, development and production operations on Block 20 until our Production Sharing Agreement for Block 20 is successfully negotiated and executed." Our prospect interests are subject to customary royalty and other interests, liens under operating agreements, 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.

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 and transportation 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 pollution from our operations.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. Compliance with these laws 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 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 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 for 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, 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, results of operations or ability to make distributions to you.

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.

Oil Pollution Act of 1990

The U.S. Oil Pollution Act of 1990 ("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 BOEMRE 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. There has also been a call from public interest groups, certain governmental officials and the National Commission on the BP Deepwater Horizon Spill and Offshore Drilling for, among other things, increased government oversight of the offshore oil and gas industry, to require more comprehensive financial assurance requirements, to raise or eliminate the liability cap under OPA and make the environmental review process more stringent. If adopted, certain of these proposals have the potential to adversely affect our operations by restricting areas in which we may carry out development and/or causing us to incur increased operating expenses.

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 primarily to regulation 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, that may be regulated as hazardous wastes.

Air Pollution Control

The U.S. Clean Air Act ("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.

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 federal U.S. 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. In 2009 the U.S. House of Representatives passed, and the U.S. Senate considered but did not pass, legislation that proposed, among other things, a nationwide cap on carbon dioxide and other GHG emissions and a requirement that certain emitters of GHGs, including certain electricity generators and producers and importers of specified fuels, obtain "emission allowances" to meet that cap. It is possible that federal legislation related to GHG emissions will be considered by Congress in the future.

The EPA has proposed using the CAA to limit carbon dioxide and other GHG emissions. Under EPA regulations finalized in May 2010 (referred to as the "Tailoring Rule"), the EPA began regulating GHG emissions from certain stationary sources in January 2011. Additionally, on April 1, 2010 the EPA and National Highway Transportation Administration finalized GHG emissions standards for light-duty vehicles. These two agencies are currently in the process of developing similar emission standards for medium and heavy-duty vehicles.

On September 22, 2009, the EPA issued a "Mandatory Reporting of Greenhouse Gases" final rule ("Reporting Rule"). The Reporting Rule establishes a new comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions annually on a facility-by-facility basis. On November 9, 2010 the EPA expanded the Reporting Rule to certain oil and natural gas facilities, including producers and offshore exploration and production operations. Each of these binding and proposed laws could adversely affect us directly as well as indirectly, as they could decrease the demand for oil and natural gas.

On the international level, various nations, including Angola and Gabon, have committed to reducing their GHG emissions pursuant to the Kyoto Protocol. The Kyoto Protocol is set to expire in 2012. Passage of a successor international agreement or scheme aimed at the reduction of GHGs is uncertain. U.S. federal climate change regulation or laws or climate change regulation 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 and will be 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
- 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. Upon us reaching the production stage of our business model, such regulations will be applicable to us.

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 regulation, respectively. These regulations may govern licensing for drilling operations, mandatory involvement of local partners in our operations, taxation of our revenues, safety and environmental matters and our ability to operate in such jurisdictions as a foreign participant.

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. We have engaged third party consultants to assist us with our compliance efforts in Angola.

Employees

As of December 31, 2010, we had 61 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, 2010, we had 31 consultants and secondees working in our offices.

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 Securities and Exchange Commission ("SEC"), including our Annual Report on Form 10-K, 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 or by calling 1-800-SEC-0330. 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.

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	55	Chairman of the Board of Directors and Chief Executive Officer
Samuel H. Gillespie	68	General Counsel and Executive Vice President
John P. Wilkirson	53	Chief Financial Officer and Executive Vice President
James H. Painter	53	Executive Vice President, Gulf of Mexico
Van P. Whitfield	59	Executive Vice President, Operations and Development
Michael D. Drennon	55	Executive Vice President and General Manager, Cobalt Angola
James W. Farnsworth	55	Chief Exploration Officer
Lynne L. Hackedorn	52	Vice President, Government, Public Affairs and Land
Richard A. Smith	51	Vice President, International Business Development, Commercial and Finance

Biographical information

Joseph H. Bryant has been our Chief Executive Officer and Chairman of our Board of Directors since our inception in November 2005. Mr. Bryant has 33 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 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 President 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 currently also serves on the board of directors of the Berry Petroleum Company, an independent energy company and the American Petroleum Institute. Mr. Bryant holds a Bachelor of Science in Mechanical Engineering from the University of Nebraska.

Samuel H. Gillespie has been our General Counsel and Executive Vice President since our inception in November 2005. He served as Vice Chairman of our Board of Directors from our inception until October 2009. Mr. Gillespie has 30 years of experience in the oil and gas industry. Prior to joining Cobalt, from 2003 to 2005, Mr. Gillespie was Senior Vice President and General Counsel of Unocal Corporation. From 2001 to 2003, Mr. Gillespie was Special Counsel at Skadden, Arps, Meagher & Flom, LLP & Affiliates. From 1994 to 2001, Mr. Gillespie was Senior Vice President and General Counsel of Mobil Corporation. While at these companies Mr. Gillespie led key negotiations, including Mobil Corporation's global merger with Exxon Corporation and Unocal Corporation's merger with Chevron Corporation. He was also instrumental in the expansion of Mobil Corporation's and Unocal Corporation's exploration and production opportunities in Kazakhstan, Turkmenistan, Qatar, Indonesia, Thailand, Bangladesh, Russia, Azerbaijan, Nigeria, Cameroon, Vietnam, Venezuela and Peru. Mr. Gillespie holds a Bachelor of Arts from Middlebury College and a J.D. from Vanderbilt University.

John P. Wilkirson has served as Executive Vice President and Chief Financial Officer since June 2010. From 2007 until June 2010, Mr. Wilkirson served as our Vice President, Strategic Planning and Investor Relations. Mr. Wilkirson has 30 years of experience in the energy industry. Prior to joining Cobalt, from 1998 to 2005, Mr. Wilkirson was Vice President, Strategic Planning and Economics of Unocal Corporation, where his primary responsibilities included identifying and addressing major strategic issues, managing the global asset and investment portfolio, leading the economic analysis and evaluations function and overseeing performance management. He played an instrumental role as the integration executive for Unocal Corporation's merger into Chevron Corporation. Prior to Unocal Corporation, from 1992 to 1997, Mr. Wilkirson was an Engagement Manager at McKinsey & Company, Inc., a management consulting firm, serving energy clients on strategy and performance improvement engagements. Additional industry experience includes positions at Exxon Company USA from 1980 to 1984 and Sohio Petroleum Company and BP from 1984 to 1991, in petroleum engineering and commercial assignments. Mr. Wilkirson has a Bachelor of Science with Highest Honors in Petroleum Engineering and a Master of Business Administration from the University of Texas at Austin.

James H. Painter has served as our Executive Vice President, Gulf of Mexico since our inception in November 2005. Mr. Painter has more than 26 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.

Van P. Whitfield has served as our Executive Vice President, Operations and Development since May 2006. Mr. Whitfield has over 36 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.

James W. Farnsworth has been our Chief Exploration Officer since our inception in November 2005. Mr. Farnsworth has had more than 26 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.

Michael D. Drennon has been our Executive Vice President and General Manager, Cobalt Angola since April 2010 and has 34 years of industry experience. Prior to joining Cobalt, Mr. Drennon served as Vice President, Operations for Parker Drilling Company from 2005 until April 2010. Mr. Drennon's additional industry experience includes various executive positions at BP and Amoco in the United States, United Kingdom, China, Trinidad, Norway and Angola. Mr. Drennon received a Bachelor of Science Degree in Petroleum Engineering from Texas Tech University in 1977.

Lynne L. Hackedorn has served as Vice President, Government, Public Affairs and Land since September 2010. From April 2006 until September 2010, Ms. Hackedorn served as our Vice President, Land. Ms. Hackedorn has over 26 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 earned her Bachelor of Science in Petroleum Land Management from the University of Houston, graduating Magna Cum Laude.

Richard A. Smith has served as Vice President, International Business Development, Commercial and Finance since September 2010. From October 2007 until September 2010, Mr. Smith served as our Vice President. Mr. Smith has over 28 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.

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, 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

We have no proved reserves and areas that we decide to drill may not yield oil in commercial quantities or quality, or at all.

We have no proved reserves. We have identified prospects based on available seismic and geological information that indicates the potential presence of oil. However, the areas we decide to drill may not yield oil in commercial quantities or quality, or at all. 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. Exploratory wells have been drilled on only four of our prospects. Accordingly, we do not know if any of our prospects will contain oil in sufficient quantities or quality to recover drilling and completion costs or to be economically viable. Even if oil is found on our prospects in commercial quantities, construction costs of oil pipelines or floating production systems, as applicable, and transportation costs may prevent such prospects from being economically viable.

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.

Furthermore, recent pre-salt hydrocarbon discoveries in Brazil and prior pre-salt discoveries onshore West Africa, and the successful drilling results there, may not prove to be analogies for our properties offshore West Africa. Additionally, the few wells drilled offshore Angola, including the Baleia well on Block 20, that did not target pre-salt horizons but nevertheless had pre-salt oil shows may not prove analogous to our exploratory wells. To date, no exploratory wells have been drilled which had the primary objective of targeting the pre-salt horizon in the deepwater offshore Angola and Gabon.

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 efforts, has only recently been considered as a potentially economically viable production area due to the costs and difficulties involved in drilling for oil at such depths. To date there has not been commercially successful production in the inboard Lower Tertiary trend. We may not be successful in developing commercially viable production in this trend.

We face substantial uncertainties in estimating the characteristics of our prospects, so you should not place undue reliance on any of our estimates.

In this Annual Report on Form 10-K we provide estimates of the characteristics of our prospects, such as the mean area (acres), mean net pay thickness (feet) and hydrocarbon yield (barrels of oil-equivalent per acre-foot), for the basins in which our prospects are located. These estimates may be incorrect, as the accuracy of these estimates is a function of the available data, geological interpretation and judgment. To date, only four of our prospects have been drilled. Any analogies drawn by us from other wells, prospects or producing fields may not prove to be accurate indicators of the success of developing reserves from our prospects. Furthermore, we have no way of evaluating the accuracy of the data from analog wells or prospects produced by other parties which we may use.

It is possible that none of the drilled wells will find accumulations of oil. Any significant variance between actual results and our assumptions could materially affect the quantities of oil attributable to any particular group of properties. In this Annual Report on Form 10-K, we refer to the "mean" of the estimated data. This measurement is statistically calculated based on a range of possible values of such estimates, with such ranges being particularly large in scope. Therefore, there may be large discrepancies between the mean estimate provided in this Annual Report on Form 10-K and our actual results.

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 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. Exploratory wells bear a much greater risk of financial loss than development wells. Moreover, the successful drilling of an oil well does not necessarily result in a profit on investment. Most of the wells we plan to operate or participate in in the near term are exploratory wells. A variety of factors, both geological and market-related, can cause a well 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 development, regulatory approval and commitments of resources prior to commercial development. 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.

The explosion and sinking of the Deepwater Horizon drilling rig in the U.S. Gulf of Mexico, the resulting oil spill and the legislative and regulatory response thereto may materially adversely impact our operations and may have significantly increased certain of the risks we face.

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 massive oil spill. Hydrocarbons discharged continuously from the well since the time of this disaster until July 15, 2010 when a capping mechanism temporarily stopped the flow of hydrocarbons and until September 19, 2010 when efforts to permanently stop the flow of hydrocarbons from the well were successful. Although we have no economic interest in this well or the Deepwater Horizon, all of our and our partners' plans for exploration and appraisal drilling activities in the U.S. Gulf of Mexico, including our North Platte #1 exploratory well and Anadarko's Heidelberg #3 appraisal well, were suspended and continue to be significantly delayed as a result of the response by the U.S. government and its regulatory agencies to the Deepwater Horizon incident.

The U.S. government and its regulatory agencies with jurisdiction over oil and gas exploration, including the DOI and the BOEMRE, have responded to this incident by imposing moratoria on drilling operations, by requiring operators to reapply for exploration plans and drilling permits which had previously been approved and by adopting 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. We are diligently working to fully understand and comply with all of these new regulations, recognizing that we will be unable to resume operations until we can do so. Compliance with these new regulations and new interpretations of existing regulations may materially increase the cost of our drilling operations in the U.S. Gulf of Mexico, which could materially adversely impact our business, financial position or results of operations.

We do not know when we will be able to resume drilling operations in the U.S. Gulf of Mexico or at what cost. The uncertainty surrounding the timing and cost of our drilling activities in the U.S. Gulf of Mexico is primarily the result of (i) newly issued regulations by the DOI and BOEMRE, (ii) ongoing clarifications and interpretive guidance often in the form of an NTL issued by the DOI and the BOEMRE relating to these newly issued regulations as well as with respect to existing regulations, (iii) our continuing compliance efforts relating to these regulations, clarifications and guidance, (iv) uncertainty as to the ability of the BOEMRE to timely review submissions and issue drilling permits, (v) the general uncertainty regarding additional regulation of the oil and gas industry's operations in the U.S. Gulf of Mexico and (vi) ongoing and potential third party legal challenges to industry drilling operations in the U.S. Gulf of Mexico.

On January 3, 2011, we received a letter from the BOEMRE describing the conditions under which we may resume our drilling operations that were suspended as a result of the Deepwater Horizon event. At the time of the BOEMRE suspension on May 27, 2010, we were running storm anchors to secure the Ocean Monarch drilling rig to spud our North Platte #1 exploratory well. We understand that twelve other operators received a similar letter. Our letter is only applicable to our North Platte #1 exploratory well that was suspended on May 27, 2010. On February 23, 2011, we received a letter from the BOEMRE notifying us of the BOEMRE's approval of the exploration plan for our North Platte #1 exploratory well. However, we will not be able to restart operations on our North Platte #1 exploratory well until we establish, to the BOEMRE's satisfaction, our compliance with NTL #10 and the BOEMRE approves our application for permit to drill. We are also awaiting responses on the various submissions we have made to the BOEMRE under applicable regulations, including the most recent version of our OSRP that we submitted in advance of the regular expiration of our prior OSRP in December 2010 and submissions regarding our available containment resources that we submitted upon joining the Helix Well Containment Group as required by NTL #10. At this time, we do not know and we are unable to estimate when we will be able to restart our operations at the North Platte #1 exploratory well. In addition, even if we are able to restart our operations at the North Platte #1 exploratory well, we do not know and we are unable to estimate when we will be able to restart the remainder of our U.S. Gulf of Mexico drilling program, including our Ligurian #2 exploratory well, given that the above-mentioned January 3, 2011 and February 23, 2011 BOEMRE letters are applicable only to our North Platte #1 exploratory well.

The successful execution of our U.S. Gulf of Mexico business plan depends on our ability to continue our exploration and appraisal efforts. Given the current restrictions, potential future restrictions and the uncertainty surrounding the availability of any exceptions to any restrictions, we cannot predict when we will be able to continue our exploratory and appraisal program in the U.S. Gulf of Mexico, if at all. A prolonged suspension of or delay in our drilling operations would adversely affect our business, financial position or future results of operations.

In addition, we cannot predict how federal and state authorities will further respond to the Deepwater Horizon incident or whether additional changes in laws and regulations governing oil and gas operations in the U.S. Gulf of Mexico will result or how the BOEMRE will interpret or enforce the rules and regulations issued in response to the Deepwater Horizon incident. It is possible that additional regulations or limitations may be imposed on us. There are currently numerous bills before the U.S. Congress which seek to impose strict regulations concerning the operations and financial strength of companies involved in the exploration and production of hydrocarbons in the U.S. Gulf of Mexico. Such regulations may require a change in the way we conduct our business, may increase our costs of doing business, may delay our business plans or may ultimately prohibit us (either explicitly or as a result of our inability to meet certain prescribed conditions such as increased minimum insurance or bonding requirements) from drilling for or producing hydrocarbons in the U.S. Gulf of Mexico. We cannot predict with any certainty what form any additional laws or regulations will take, how they will be interpreted or enforced, or the extent to which they may impact our business, financial position or future results of operations.

Furthermore, the Deepwater Horizon incident may have increased 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 and increased potential liability thresholds under proposed amendments to environmental regulations;
- decreased access to appropriate equipment, personnel and infrastructure in a timely manner;
- 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 thereof, 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 compliance 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 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 on installation or operation of gathering or processing facilities;
- restrictions on the use of certain operating practices;
- legal challenges or lawsuits;
- damaging publicity about us;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse affects 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 have contracted to use the Ensco 8503 drilling rig in the U.S. Gulf of Mexico and are required to make certain payments under such rig agreement even if we cannot use it.

The Ensco 8503 drilling rig, which we have recently accepted, has departed the U.S. Gulf of Mexico for French Guiana on an approximate five month direct sublet from its owner, Ensco to Tullow, inclusive of mobilization and demobilization. We will only be obligated to pay certain amortized costs associated with certain rig upgrades during the term of the sublet. Upon return of the Ensco 8503 drilling rig to us, a special reduced standby rate of $210,000 per day will become payable by us under the Standby Agreement that we executed with Ensco on November 9, 2010. This special reduced standby rate will be payable until early 2012 or, if earlier, when we are able to resume drilling operations or elect to begin the two year term of the base drilling contract.

We entered into the base drilling contract related to the Ensco 8503 drilling rig with Ensco on May 8, 2008. This contract has a two year term, which would have commenced upon delivery and acceptance had we not entered into the Standby Agreement and which may be extended by us for one or two additional years. This two year term is not affected by the Standby Agreement and such term is expected to commence at the conclusion of the term of the Standby Agreement at the agreed base operating rate of $510,000 per day, subject to adjustment, which aggregates to approximately $372 million over the two years of the base contract. We do not know when or if we will be able to resume any drilling operations in the U.S. Gulf of Mexico and, therefore, we do not know when we will be able to use the Ensco 8503 drilling rig. Absent force majeure circumstances, additional third party sublets and/or an agreement with Ensco to the contrary, we will be required to make the payments discussed above even if we are unable to use the Ensco 8503 drilling rig.

We will not have a license for Block 20 offshore Angola and we will not be able to commence our exploration, development and production operations on Block 20 until our Production Sharing Agreement for Block 20 is successfully negotiated and executed.

On January 24, 2011, we announced that we had been conditionally awarded a 40% interest and had been indicated as operator of Block 20 offshore Angola. Along with the other successful companies in this bid round, we are currently negotiating definitive agreements, including the Production Sharing Agreement, that will govern the exploration, development and production operations on Block 20. Our

Block 20 award will not be final and we will not have a license for Block 20 unless and until our Production Sharing Agreement for Block 20 is successfully negotiated and executed. The execution of the Production Sharing Agreement is a key milestone that secures our rights to Block 20 and allows for the commencement of our exploration program on Block 20. As certain terms of our Block 20 award have not been finalized, there is a risk that the Production Sharing Agreement will not be executed and that we may be unable to enforce any contractual rights we have in Block 20 and we will not be able to commence our exploration, development and production operations on Block 20. Further, if the Production Sharing Agreement is executed later than we expect, our planned 2011 activities in Angola could be delayed.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has identified and scheduled drilling locations on our acreage over a multi-year period. Our ability to drill and develop these locations depends on a number of factors, including the availability of equipment and capital, seasonal conditions, regulatory approvals, oil prices, costs and drilling results. The final determination on whether to drill any of these drilling locations 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 with respect to our established drilling locations. Because of these uncertainties, we do not know if the drilling locations we have identified will be drilled within our expected timeframe or at all or if we will be able to economically produce oil from these or any other potential drilling locations. As such, our actual drilling activities may be materially different from our current expectations, which could adversely affect our results of operations and financial condition.

We are not, and may not be in the future, the operator on all of our prospects, and do not, and may not in the future, hold all of the working interests in our prospects. 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.

Currently, we are not the operator on approximately 25% of our U.S. Gulf of Mexico blocks, and we are not the operator on the Diaba Block offshore Gabon. 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 could prevent us from realizing our target returns for those prospects. Further, it may be difficult for us to pursue one of our key business strategies of minimizing 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;
- approval of other participants in drilling wells;
- 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.

Our operations could be adversely impacted by our block partnership with an entity whose affiliate is involved in the Deepwater Horizon incident.

An affiliate of an oil and gas company which holds a participating interest in the well that the Deepwater Horizon drilling rig was drilling at the time of the incident (the "Macondo Well") also owns participating interests in nine blocks in which we also own participating interests, including the six blocks associated with our two previously announced discoveries of Heidelberg and Shenandoah. As a 25% non-operating interest owner in the Macondo Well, such participant may incur liability under environmental and other laws and may be required to contribute to the significant and ongoing remediation expenses in the U.S. Gulf of Mexico. This event and its aftermath could result in substantial costs to such participant and could in turn affect such participant's ability, desire and timeline related to further exploration, appraisal or development activities on the nine blocks in which we both have interests, including further appraisal and development activities with respect to our two discoveries. This could further delay our commencement of production in the U.S. Gulf of Mexico and cause a material adverse effect on our business, results of operations and financial condition.

We have a limited operating history and our future performance is uncertain.

We are a development stage enterprise and will continue to be so until commencement of substantial production from our oil properties, which will depend upon our ability to conduct drilling operations, successful drilling results, additional and timely capital funding, and access to suitable infrastructure and adequate personnel. We do not expect to commence production for at least several years, and therefore we do not expect to generate any revenue from production for a long time. Companies in their initial stages of development face substantial business 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 drilling program. We face challenges and uncertainties in financial planning as a result of the unavailability of historical data and uncertainties regarding the nature, scope and results of our future activities. New companies must develop successful business relationships, establish operating procedures, hire staff, install management information and other systems, establish facilities and obtain licenses, as well as take other measures necessary to conduct their intended business activities. We may not be successful in implementing our business strategies, in establishing necessary staffing or personnel levels, or in completing the development of the infrastructure necessary to conduct our business as planned. In the event that one or more of our drilling programs is not completed, is delayed 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.

We are dependent on certain members of our management and technical team.

Investors in our common stock 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. 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. In making a decision to invest in our common stock, you must be willing to rely to a significant extent on our management's discretion and judgment. The loss of any of our management and technical team members 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.

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 develop our exploration and production plans.

We expect our capital outlays and operating expenditures to increase substantially over at least the next several years as we expand our operations. Exploration and production plans 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, strategic alliances or debt financing, before we achieve commercialization of any of our properties.

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

- the scope, rate of progress and cost of our exploration and production activities;
- 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;
- the terms and timing of any drilling and other production-related arrangements that we may enter into;
- the cost and timing of governmental approvals and/or concessions; and
- the effects of competition by larger companies operating in the oil and gas industry.

While we believe our operations will be adequately funded at least through 2011, we do not currently have any commitments for future external funding and we do not expect to generate any revenue from production before several years after the end 2011. Additional financing may not be available on favorable terms, or at all. Even if we succeed in selling additional securities to raise funds, at such time the ownership percentage of our existing stockholders would 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 prospects, we may lose operating control over such prospects.

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 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 continue our exploration and production activities or successfully exploit our properties, and we may lose the rights to develop these properties upon the expiration of our licenses.

A substantial or extended decline in oil prices may adversely affect our business, financial condition and results of operations.

The price that we will receive for our oil production will significantly affect our revenue, profitability, access to capital and future growth rate. Historically, the oil markets have been volatile and will likely continue to be volatile in the future. The prices that we will receive for our production and the levels of our production depend on numerous factors. 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 ("OPEC");
- 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;
- 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 exploration and production activity;
- the level of global oil inventories and oil refining capacities;
- weather conditions and other natural disasters;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil; and
- the price and availability of alternative fuels.

Oil prices have fluctuated dramatically in recent times and will likely continue to be volatile in the future. Lower oil prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil that we can produce economically. A substantial or extended decline in oil prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Our inability to access appropriate equipment and infrastructure in a timely manner may hinder our access to oil markets or delay our production.

Our ability to market our oil production will depend substantially on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We also rely on continuing access to drilling rigs suitable for the environment in which we operate. We may be required to shut in oil wells because of the absence of a market or because access to pipelines, gathering systems or processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver the production to market, which could cause a material adverse effect on our results of operations and financial condition.

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

Oil 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 that will allow us to take advantage of our findings. Additionally, our oil properties are located in deepwater, which generally increases the capital and operating costs, technical challenges and risks associated with oil exploration and production activities. As a result, our oil exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable oil 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 oil production from our prospects will also be affected by numerous factors. These factors include, but are not limited to, market fluctuations of 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 oil, environmental protection and climate change). The effect of these factors, individually or jointly, may result in us not receiving an adequate return on invested capital.

In the event that our drilling programs are developed and become operational, they may not produce oil in commercial quantities or at the costs anticipated, and our projects may cease production, in part or entirely, in certain circumstances. Drilling programs may become uneconomic as a result of an increase in operating costs to produce oil. Our actual operating costs may differ materially from our current estimates. Moreover, it is possible that other developments, such as increasingly strict environmental, health and safety laws and regulations and enforcement policies thereunder and claims for damages to natural resources, property or persons resulting from our operations, could result in substantial costs and liabilities, delays, an inability to complete our drilling programs or the abandonment of such drilling programs, which could cause a material adverse effect on our results of operations and financial condition.

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 of oil or well fluids;
- fires;
- marine hazards with respect to offshore operations;
- formations with abnormal pressures;
- pollution and other environmental risks; and
- natural disasters.

These risks are particularly acute in deepwater drilling and exploration or natural resources. Any of these events could result in loss of human life, significant damage to property, environmental damage, impairment of our operations and substantial losses. In accordance with customary industry practice, we expect to maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events whether or not covered by insurance, could have a material adverse effect on our financial position and results of operations.

The development schedule of oil projects, including the availability and cost of drilling rigs, equipment, supplies, personnel and oilfield services, is subject to delays and cost overruns.

Historically, some oil projects have experienced delays and capital cost increases and overruns due to, among other factors, the unavailability or high cost of drilling rigs and other essential equipment, supplies, personnel and oilfield services. The cost to develop our projects has not been fixed and remains dependent upon a number of factors, including the completion of detailed cost estimates and final engineering, contracting and procurement costs. Our construction and operation schedules may not proceed as planned and may experience delays or cost overruns. Any delays may increase the costs of the projects, requiring additional capital, and such capital may not be available in a timely and cost-effective fashion.

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 the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties. In particular, we are not intending to put in place business interruption insurance due to the fact that this is not economically viable, and therefore we may not be able to rely on insurance coverage in the event of such natural phenomena.

Deepwater exploration generally involves greater operational and financial risks than exploration on the shelf. Deepwater drilling generally requires more time and more advanced drilling technologies, involving a higher risk of technological failure and usually higher drilling costs. Such risks are particularly applicable to our deepwater exploration efforts in the Lower Tertiary trend and pre-salt offshore Angola and Gabon, as there has been limited drilling activity in these areas. 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 generally, and operations in the Lower Tertiary and offshore West Africa trends in particular, lack the physical and oilfield service infrastructure present on the shelf. As a result, a significant amount of time may elapse between a deepwater discovery and the marketing of the associated oil, increasing both the financial and operational risk involved with these operations. Because of the lack and high cost of this infrastructure, reserve discoveries we make in the deepwater, if any, may never be economically producible.

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 wellsites 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 impact on our financial condition and results of operations.

The geographic concentration of our properties in the U.S. Gulf of Mexico and offshore Angola and Gabon subjects us to an increased risk of loss of revenue or curtailment of production from factors specifically affecting the U.S. Gulf of Mexico and offshore Angola and Gabon.

Our properties are concentrated in three countries: the U.S. Gulf of Mexico and offshore Angola and Gabon. Some or all of these properties could be affected should such regions experience:

- severe weather;
- moratoria on drilling or permitting delays;
- delays or decreases in production;
- delays or decreases in the availability of 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 and fiscal environment.

For example, in response to the Deepwater Horizon incident, the U.S. government and its regulatory agencies with jurisdiction over oil and gas exploration, including the DOI and the BOEMRE, have imposed moratoria on drilling operations, required operators to reapply for exploration plans and drilling permits and adopted extensive new regulations, which have effectively halted drilling operations in the deepwater U.S. Gulf of Mexico. Additionally, oil properties located in the U.S. Gulf of Mexico were significantly damaged by Hurricanes Katrina and Rita, 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 plan to 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.

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.

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

Our non-U.S. oil 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, foreign exchange restrictions, currency fluctuations, royalty and tax increases and other risks arising out of foreign governmental sovereignty over the areas in which our operations are conducted, as well as risks of loss due to civil strife, acts of war, guerrilla activities and insurrection. These risks may be higher in the developing countries in which we conduct our activities, namely, Angola and Gabon.

Our operations in these areas increase our exposure 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;
- lead to U.S. government or international sanctions; and
- limit access to markets for periods of time.

Countries in West Africa have experienced political instability in the past. Disruptions may occur in the future, and losses caused by these disruptions may occur that will not be covered by insurance. Consequently, our non-U.S. 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.

The oil and gas industry, including the acquisition of exploratory acreage in the U.S. Gulf of Mexico and offshore West Africa, is intensely competitive.

The international oil and gas industry, including in the U.S. Gulf of Mexico and West Africa, is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply. We operate in a highly competitive environment for acquiring exploratory 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 oil 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 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 cause a material adverse effect on our results of operations and financial condition.

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 for drilling operations;
- royalty increases, including retroactive claims;
- drilling and development bonds;
- reports concerning operations;
- the spacing of wells;
- unitization of oil accumulations;
- remediation or investigation activities for environmental purposes; and
- taxation.

Under these and other laws and regulations, we could be liable for personal injuries, property damage and other types of damages. 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 financial condition and results of operations.

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, 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 requirements, our leases 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 our leases, 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, 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 to increase significantly or eliminate financial liability caps and require significantly more comprehensive financial assurance requirements under OPA 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 ("GHG"), 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 U.S. Environmental Protection Agency began regulating GHG emissions from certain stationary sources on January 2, 2011 and has enacted and proposed GHG emissions standards for certain classes of vehicles. 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." See "Business—Impact of the U.S. Gulf of Mexico Oil Spill."

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.

We believe that we are, and will remain for the foreseeable future, a U.S. real property holding corporation for U.S. federal income tax purposes. 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 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 be exposed to liabilities under the Foreign Corrupt Practices Act, and any determination that we violated the Foreign Corrupt Practices Act could have a material adverse effect on our business.

We are subject to the 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 Risk Services Agreements 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 is limited. However, last year we were made aware of allegations, that we are continuing to look into, of a connection between senior Angolan government officials and Nazaki (a full paying member of the contractor group for Blocks 9 and 21). 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.

We may incur substantial losses and become subject to liability claims as a result of future oil and natural gas operations, for which we may not have adequate insurance coverage.

We intend to maintain insurance against risks in the operation of the business we plan to develop and in amounts in which we believe to be reasonable. Such insurance, however, may contain exclusions and limitations on coverage. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

The recent adoption of The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, could have an adverse effect on our business.

The Dodd-Frank Act requires, no later than 270 days after the enactment of the Dodd-Frank Act, the SEC to promulgate rules requiring SEC reporting companies that engage in the commercial development of oil, natural gas or minerals, to include in their annual reports filed with the SEC disclosure about all payments (including taxes, royalties, fees and other amounts) made by the issuer or an entity controlled by the issuer to the United States or to any non-U.S. government for the purpose of commercial development of oil, natural gas or minerals. As these rules are yet to be released and are not yet effective, we are unable to predict what form these rules may take and whether we will be able to comply with them without adversely impacting our business, or at all. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

Our business could be affected by recent health care reform and potential federal tax increases.

In March 2010, the Patient Protection and Affordable Care Act ("PPACA") and the Health Care and Education Reconciliation Act of 2010 ("HCERA"), which makes various amendments to certain aspects of the PPACA (the HCERA and, together with PPACA, the "Acts"), were signed into law. Among numerous other items, the Acts reduce the tax benefits available to an employer that receives the Medicare Part D subsidy and impose excise taxes on high-cost health plans. We are not a recipient of the Medicare Part D tax benefit and therefore, we will not be impacted by this part of the new legislation. We will continue to monitor the potential impact of these new regulations as details emerge over the next several months and years. At this point in time, we are not aware of any material impacts to us.

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 price of oil and natural gas;

- the success of our exploration and development operations, and the marketing of any oil we produce;
- 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;
- 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 of any additional securities of ours;
- investor perception of our company and of the industry in which we compete; 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 initial public offering 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 became eligible for sale in the public market in late 2010, subject in certain circumstances to the volume, manner of sale 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.

The concentration of our capital stock ownership among our largest stockholders, and their affiliates.

Our four largest stockholders collectively own approximately 72% of our outstanding common stock. Consequently, these stockholders have significant 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 will limit your ability to influence corporate matters, and as a result, actions may be taken that you may not view as beneficial.

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.

We are a "controlled company" within the meaning of the NYSE rules and, as a result, we qualify for and rely on exemptions from certain corporate governance requirements.

Funds affiliated with First Reserve Corporation, Goldman, Sachs & Co., Riverstone Holdings LLC and The Carlyle Group, and KERN Partners Ltd. and certain limited partners in such funds affiliated with KERN Partners Ltd., respectively, control a majority of the voting power of our outstanding common stock. Consequently we are a "controlled company" within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a "controlled company" and may elect not to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of the board of directors consist of independent directors;
- the nominating and corporate governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities;
- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- there be an annual performance evaluation of the nominating and corporate governance and compensation committees.

We are currently treated as a controlled company and utilize these exemptions, including the exemption for a board of directors composed of a majority of independent directors. In addition, although we have adopted charters for our audit, nominating and corporate governance and compensation committees and conduct annual performance evaluations for these committees, only the audit committee is presently composed entirely of independent directors. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the NYSE corporate governance requirements.

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

Not applicable.

Item 2. ***Properties***

Please refer to the information under the captions "Business—Deepwater U.S. Gulf of Mexico" and "Business—West Africa Deepwater" elsewhere in this Annual Report on Form 10-K.

Item 3. ***Legal Proceedings***

We are not currently party to any legal proceedings. However, from time to time we 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 our consolidated financial position, results of operations, or liquidity.

Item 4. ***(Removed and Reserved)***

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 New York Stock Exchange under the symbol "CIE." On February 25, 2011, the last reported sale price for our common stock on New York Stock Exchange was $15.14 per share. The following table sets forth, for the periods indicated, the reported high and low sale prices for our common stock on the New York Stock Exchange.

	High	Low
Year ending December 31, 2011		
First Quarter (through February 25, 2011)	$15.37	$12.39
Year ended December 31, 2010		
Fourth Quarter	$13.50	$ 8.99
Third Quarter	10.01	7.00
Second Quarter	14.22	6.16
First Quarter	16.07	11.85
Year ended December 31, 2009		
Fourth Quarter (period from December 16, 2009 through December 31, 2009)	$14.20	$12.50

Holders

As of February 25, 2011, there were approximately 91 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

To date, we have not paid any dividends since becoming a public company. 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 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.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

We did not repurchase any of our outstanding equity securities during the most recent fiscal quarter.

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 and cash flows information for the years ended December 31, 2010, 2009, 2008, 2007, and 2006 were derived from Cobalt International Energy, Inc.'s audited financial statements.

Consolidated Statement of Operations Information:

	Year Ended December 31,				
	2010	2009	2008	2007	2006
	($ in thousands except per share data)				
Oil and gas revenue	$ —	$ —	$ —	$ —	$ —
Operating costs and expenses					
Seismic and exploration	45,030	30,666	41,274	86,813	92,434
Dry hole expense and impairment	44,178	14,486	—	—	—
General and administrative	48,063	35,996	31,271	23,090	19,423
Depreciation and amortization	787	622	683	435	292
Total operating costs and expenses	138,058	81,770	73,228	110,338	112,149
Operating income (loss)	(138,058)	(81,770)	(73,228)	(110,338)	(112,149)
Other income (expense):					
Interest income	1,582	513	1,632	1,384	622
Total other income (expense)	1,582	513	1,632	1,384	622
Net income (loss) before income tax	(136,476)	(81,257)	(71,596)	(108,954)	(111,527)
Income tax expense (benefit)(1)(2)	—	—	—	—	—
Net income (loss)	$ (136,476)	$ (81,257)	$(71,596)	(108,954)	(111,527)
Basic and diluted income (loss) per common share	$ (0.39)				
Weighted average number of common shares—basic and diluted	349,342,050				
Pro forma net income (loss) (unaudited)(1):					
Net income (loss) as reported		$ (81,257)			
Pro forma income tax expense(2)		—			
Pro forma management fees(3)		2,872			
Pro forma net income (loss) allocable to common shareholders		$ (78,385)			
Pro forma basic and diluted income (loss) per share(4)		$ (0.33)			
Pro forma weighted average number of common shares—basic and diluted(5)		236,751,219			

(1) Upon completion of our IPO, Cobalt International Energy, L.P. became wholly-owned by Cobalt International Energy, Inc. Upon the completion of our corporate reorganization, all of Cobalt International Energy, L.P.'s outstanding limited partnership interests were exchanged for shares of Cobalt International Energy, Inc.'s common stock based on these interests' relative rights as set forth in Cobalt International Energy, L.P.'s limited partnership agreement. Additionally, we became subject to federal and state income taxes.

(2) 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.

(3) Upon completion of the corporate reorganization the right of our former private equity owners to receive a management fee terminated.

(4) Nonvested restricted stock awards of 8,015,041 as of December 31, 2009 were excluded from the pro forma calculation of diluted income (loss) per common share because they were anti-dilutive for the applicable period.

(5) The pro forma weighted average common shares outstanding have been calculated as if the conversion of all partnership units into shares of common shares occurred as of the beginning of the year.

Consolidated Balance Sheet Information:

	As of December 31,				
	2010	**2009**	**2008**	**2007**	**2006**
	($ in thousands)				
Cash and cash equivalents(1)	$ 302,720	$1,093,100	$ 5,103	$ 95,946	$10,631
Short-term investments	534,933	—	—	—	—
Total current assets	889,632	1,153,946	23,876	99,371	11,726
Total property, plant and equipment(2)	463,769	471,612	760,728	122,097	50,915
Restricted cash	338,515	186,547	—	—	—
Long-term investments	40,003	—	—	—	—
Total assets	1,746,443	1,812,105	784,604	254,658	62,726
Total current liabilities(3)	24,559	70,523	44,133	10,785	16,166
Total long term liabilities	2,850	—	—	—	—
Total partners' capital/stockholders' equity	1,719,034	1,741,582	740,471	243,873	46,560
Total liabilities and partners' capital/stockholders' equity	1,746,443	1,812,105	784,604	254,658	62,726

(1) The cash balance at December 31, 2009 includes the proceeds from the initial public offering. As of December 31, 2010, majority of the funds were invested in short-term and long-term debt securities. The cash balance at December 31, 2007 represents cash on hand for anticiptated lease awards by the BOEMRE for the 2007 Central Gulf of Mexico Lease Sales.

(2) The decrease from December 31, 2008 to December 31, 2009 reflects the farm-out of the U.S. Gulf of Mexico lease interests to Total and Sonangol. The year-to-year variances from 2007 to 2008 represent additions to our lease inventory in the U.S. Gulf of Mexico and offshore Angola and Gabon.

(3) The increase in current liabilities at December 31, 2009 consists of year-end accruals for seismic data in West Africa.

Consolidated Statement of Cash Flows Information:

	Year Ended December 31,				
	2010	**2009**	**2008**	**2007**	**2006**
	($ in thousands)				
Net cash provided by (used in):					
Operating activities	$(133,264)	$ (75,486)	$ (48,420)	$(116,050)	$(95,607)
Investing activities	(758,372)	87,123	(608,876)	(103,770)	(51,229)
Financing activities	101,256	1,076,360	566,453	305,135	154,984

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," "Business—How We Identify and Analyze Prospects" 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 the information presented under "Selected Financial Data." Due to the fact that we have not generated any revenues, 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 once we begin to generate revenues. 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, oil-focused exploration and production company with a world-class below salt prospect inventory in the deepwater of the U.S. Gulf of Mexico and offshore Angola and Gabon in West Africa. We have established a current portfolio of 132 identified, well defined prospects, comprised of 47 prospects located in the deepwater U.S. Gulf of Mexico and 85 prospects located in Blocks 9 and 21 offshore Angola and the Diaba Block offshore Gabon. In addition, on January 24, 2011 we announced that we had been conditionally awarded a 40% working interest and indicated as operator of Block 20 offshore Angola, on which we have identified 37 prospects. See "Business—Recent Events." All of our prospects are oil-focused.

Since our formation in late 2005, we have devoted substantially all of our resources to identifying and acquiring a deepwater prospect inventory in the U.S. Gulf of Mexico and offshore Angola and Gabon in West Africa. We have also drilled as operator two exploratory wells (Ligurian #1 and Criollo #1) and participated as non-operator in three exploratory wells (Heidelberg #1, Shenandoah #1 and Firefox #1) and one appraisal well (Heidelberg #2).

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:

Success in the Discovery and Development of Oil Reserves. Because we have no operating history in the production of oil, our future results of operations and financial condition will be directly affected by our ability to discover and develop reserves through our drilling activities. Currently, our estimated oil asset base does not qualify as proved reserves. 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 asset base does not result in reserves that may eventually be commercially developed.

Oil and Gas Revenue. We have not yet commenced oil production. If and when we do commence production, we expect to generate revenue from such production. No oil and gas revenue is reflected in our historical financial statements.

Production Costs. We have not yet commenced oil production. If and when we do commence production, we will 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 annual and quarterly reporting, investor relations, registrar and transfer agent fees, incremental insurance costs, and accounting and legal services. Upon the consummation of our corporate reorganization, in connection with our initial public offering, we no longer are required to pay monitoring fees to certain limited partnership interestholders pursuant to the terms of Cobalt International Energy, L.P.'s limited partnership agreement. These differences in general and administrative expenses are not reflected in our historical financial statements other than for fiscal years 2010 and 2009.

Depreciation, Depletion and Amortization. We have not yet commenced oil or natural gas production. If and when we do commence production, 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 is susceptible to volatility related to, among other factors, 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 we expect to produce. Since we have not generated revenues, these key factors will only affect us when we produce and sell hydrocarbons.

We expect to earn income from:

- domestic sales, which consist of sales of oil and natural gas;
- sales to international markets (exports); and
- other sources, including services, investment income and foreign exchange gains.

We expect that our expenses will include:

- costs of sales (which are composed of production costs, insurance, and costs associated with the operation of our wells);
- maintenance and repair of property and equipment;
- lease rentals;
- costs of acquiring seismic data;
- depreciation and amortization of fixed assets;
- depletion of oilfields;
- exploration costs;
- selling expenses (which include expenses relating to the transportation and distribution of our products) and general and administrative expenses; and
- interest expense and foreign exchange losses.

We expect that fluctuations in our financial condition and results of operations will be driven by a combination of factors, including:

- the volume of oil we produce and sell;
- changes in the domestic and international prices of oil, which are denominated in U.S. dollars;
- our success in future bidding rounds for concessions;
- political and economic conditions in the United States, Angola and Gabon; and
- the amount of taxes and duties that we are required to pay with respect to our future operations, by virtue of our status as a U.S. company and our involvement in the oil and gas industry.

Results of Operations

The discussion of the results of operations and the period-to-period comparisons presented below analyzes our historical results. The following discussion may not be indicative of future results.

Fiscal Years Ended December 31, 2010 vs. 2009

	Year Ended December 31, 2010	Year Ended December 31, 2009	Increase (Decrease)	Percentage Change
	($ in thousands)			
Oil and gas revenue	**$ —**	**$ —**	**$ —**	**—%**
Operating costs and expenses				
Seismic and exploration	45,030	30,666	14,364	46.8%
Dry hole expense and impairment	44,178	14,486	29,692	205.0%
General and administrative	48,063	35,996	12,067	33.5%
Depreciation and amortization	787	622	165	26.5%
Total operating costs and expenses	**138,058**	**81,770**	**56,288**	**68.8%**
Operating income (loss)	**(138,058)**	**(81,770)**	**56,288**	**68.8%**
Other income (expense)				
Interest income (expense), net	1,582	513	1,069	208.4%
Total other income (expense)	**1,582**	**513**	**1,069**	**208.4%**
Net income (loss) before income tax	(136,476)	(81,257)	55,219	67.8%
Income tax expense (benefit)	—	—	—	—
Net income (loss)	**$(136,476)**	**$(81,257)**	**$55,219**	**67.8%**

Oil and gas revenue. We have not yet commenced oil production. Therefore, we did not realize any oil and gas revenue during the years ended December 31, 2010 and 2009, respectively.

Operating costs and expenses. Our operating costs and expenses consisted of the following during the years ended December 31, 2010 and 2009:

Seismic and exploration. Seismic and exploration costs increased by approximately $14.4 million during the year ended December 31, 2010, as compared to the year ended December 31, 2009. The increase in seismic and exploration costs during 2010 was primarily due to (i) a $5.1 million increase in seismic and exploration costs incurred in the U.S. Gulf of Mexico and for West Africa, (ii) $13.5 million in force majeure expenses related to the drilling rig and other equipment and services which were to be used to drill the North Platte #1 exploratory well that was suspended as a result of the Deepwater Horizon incident and (iii) $0.9 million increase in costs to ensure that the Ensco 8503 drilling rig meets the regulatory requirements for drilling in the U.S. Gulf of Mexico. The increase was offset by a $5.1 million increase in reimbursement of past seismic cost from partners. The seismic and exploration costs incurred for the year ended December 31, 2010 consisted of (i) $39.7 million incurred for seismic data acquisition and processing for the U.S. Gulf of Mexico and offshore West Africa offset by a $15.1 million reimbursement of past seismic cost from a partner in West Africa, (ii) $6.0 million for leasehold delay rentals, (iii) $13.5 million relating to force majeure expense and (iv) $0.9 million relating to costs incurred to ensure that the Ensco 8503 drilling rig meets the regulatory requirements for drilling in the U.S. Gulf of Mexico.

Dry hole expense and impairment. Dry hole expense and impairment for the year ended December 31, 2010 includes charges of $0.1 million for the Ligurian #1 exploratory well, $8.4 million for the Criollo #1 exploratory well, $11.1 million for the Heidelberg #2 appraisal well, $12.5 million for the Firefox #1 exploratory well and $2.9 million for the pre-spud costs on the North Platte #1 exploratory well. For the year ended December 31, 2009, dry hole expense consisted of $10.5 million and $4.0 million for the impaired portion of the Ligurian #1 and Criollo #1 exploratory wells, respectively. In addition, for the year ended December 31, 2010, we recorded an allowance of $9.2 million against future impairment on the carrying value of our unproved leasehold properties. No allowance against future impairment on the carry value of our unproved leasehold properties were recorded for the year ended December 31, 2009.

General and administrative. General and administrative costs increased by $12.1 million during the year ended December 31, 2010, as compared to the year ended December 31, 2009. The increase in general and administrative costs during 2010 was primarily attributed to an $8.7 million increase in costs related to equity-based compensation, an increase of $2.5 million for insurance-related expense, an increase of $1.7 million in office-related support expenses, an increase of $4.2 million for social obligation payments required by our Risk Services Agreements in Angola, an increase of $3.7 million for costs related to operating an office in Luanda, Angola, which were offset by a decrease of $2.6 million in fees paid prior to our IPO and an increase of $6.1 million in reimbursement of our general and administrative costs from our partners in the U.S. Gulf of Mexico and West Africa.

Depreciation and amortization. Depreciation and amortization did not change significantly during the year ended December 31, 2010 as compared to the year ended December 31, 2009.

Other income. Other income increased by $1.0 million for the year ended December 31, 2010 as compared to the year ended December 31, 2009. The increase of $1.0 million was primarily due to interest recognized on investment securities.

Income Taxes. As a result of net operating losses, for income tax purposes, we recorded a net deferred tax asset of $97.6 million and $28.9 million with a corresponding full valuation of $97.6 million and $28.9 million for the years ended December 31, 2010 and 2009, respectively.

Fiscal Years Ended December 31, 2009 vs. 2008

	Year Ended December 31,		Increase	Percentage
	2009	2008	(Decrease)	Change
	($ in thousands)			
Oil and gas revenue	$ —	$ —	$ —	—%
Operating costs and expenses				
Seismic and exploration	30,666	41,274	(10,608)	(25.70)%
Dry hole expense and impairment	14,486	—	14,486	—
General and administrative	35,996	31,271	4,725	15.11%
Depreciation and amortization	622	683	(61)	(8.93)%
Total operating costs and expenses	**81,770**	**73,228**	**8,542**	**11.66%**
Operating income (loss)	**(81,770)**	**(73,228)**	**8,542**	**11.66%**
Other income (expense):				
Interest income (expense), net	513	1,632	(1,119)	(68.57)%
Total other income	**513**	**1,632**	(1,119)	(68.57)%
Net income (loss)	(81,257)	(71,596)	9,661	13.49%
Income tax expense (benefit)	—	—	—	—
Net income (loss)	**$(81,257)**	**$(71,596)**	**$ 9,661**	**13.49%**

Oil and gas revenue. We have not yet commenced oil production. Therefore, we did not realize any oil and gas revenue during the years ended December 31, 2009 and 2008, respectively.

Operating costs and expenses. Our operating costs and expenses consisted of the following during the years ended December 31, 2009 and 2008:

Seismic and exploration. Seismic and exploration costs decreased by $10.6 million during the year ended December 31, 2009, as compared to the year ended December 31, 2008. The decrease in seismic and exploration costs during this period was primarily due to a decrease of $4.5 million in purchases of U.S. Gulf of Mexico seismic data, an increase of $4.1 million in the purchase of West African seismic data and a $10.2 million reimbursement from Sonangol for past seismic costs incurred by us in the U.S. Gulf of Mexico.

Dry hole expense and impairment. For the year ended December 31, 2009, we temporarily suspended operations on the Ligurian #1 exploratory well and on February 7, 2010, we suspended operations on the Criollo #1 exploratory well. Although both wells encountered oil bearing sands further technical evaluation is required to determine the commerciality of these prospects and portions of both wells were determined to have no future value. As a result, we have recorded an impairment charge to dry hole expense for the year ended December 31, 2009 of $10.5 million for the impaired portion of the Ligurian #1 well and $4.0 million for the impaired portion of the Criollo #1 well representing cost incurred during 2009.

General and administrative. General and administrative costs increased by $4.7 million during the year ended December 31, 2009, as compared to the year ended December 31, 2008. The increase in general and administrative costs during this period was primarily due to a $7.9 million increase in costs related to staff, an increase of $2.1 million for legal, accounting and consulting fees, an increase of $1.5 million in monitoring fees paid to our investors, an increase of $0.3 million in office related support expenses and a $7.1 million for recovery of general and administrative costs from our partner in the U.S. Gulf of Mexico.

Depreciation and amortization. Depreciation and amortization did not change significantly during the year ended December 31, 2009 as compared to the year ended December 31, 2008.

Other income. Our other income consisted primarily of interest income earned from cash held on deposit in our bank account. Interest income decreased by $1.1 million during the year ended December 31, 2009, as compared to the year ended December 31, 2008 due to lower interest rates on cash balances held in our bank account during the 2009 period when compared to the 2008 period.

Income Taxes. Prior to our corporate reorganization in connection with the IPO, we were not subject to federal or state income taxes. Upon completion of our corporate reorganization, we became subject to federal and state income taxes. At the time of the corporate reorganization, we recorded a net deferred tax asset of $28.9 million with a corresponding full valuation of $28.9 million.

Liquidity and Capital Resources

We are a development stage enterprise and will continue to be so until commencement of substantial production from our oil properties. As discussed in "Business—Impact of the U.S. Gulf of Mexico Oil Spill," we do not know when we will be able to resume any drilling operations in the U.S. Gulf of Mexico and, therefore, we do not know when we will be able to commence production in the U.S. Gulf of Mexico. In addition, given that our initial source of production could be from our two previously announced discoveries and that those discoveries are operated by an entity that is involved in the Deepwater Horizon incident, development plans and production from these discoveries may be further delayed. See "Item 1A. Risk Factors." Prior to the Deepwater Horizon incident, our expected time from discovery to first production was four to five years in the U.S. Gulf of Mexico. We do not know how this timeline will change as a result of new and forthcoming regulations. Offshore Angola, we expect production within five years of a commercial discovery, which will depend upon successful appraisal drilling results, additional capital funding, access to suitable infrastructure and rig availability. Until substantial production is achieved, our primary sources of liquidity are expected to be cash on hand, amounts paid pursuant to the terms of our Total alliance and funds from future equity and debt financings, asset sales and farm-out arrangements.

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

- conduct our current exploration and appraisal drilling program in the U.S. Gulf of Mexico and our current exploration drilling program offshore Angola and Gabon, including increased industry costs in the U.S. Gulf of Mexico resulting from the Deepwater Horizon incident;
- purchase and analyze seismic data in order to assess current prospects and identify future prospects;
- opportunistically invest in additional oil leases and concessional licenses in our focus areas;
- develop our discoveries which we determine to be commercially viable; 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 success of our exploration and appraisal drilling program, 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.

Our board of directors has approved a full year 2011 expenditure budget of between $180 million and $350 million for our ongoing operations and general corporate purposes, as compared to full year

2010 actual expenditures of approximately $142 million. The range of 2011 expenditures is primarily dependent on potential U.S. Gulf of Mexico drilling operations as well as potential testing and appraisal expenditures associated with any discoveries offshore Angola. Assuming we execute the Production Sharing Agreement, we expect to expend approximately $525 million for our mandatory work program and bonus payments for Block 20 over the course of the initial five year exploration period under the agreement, of which approximately $340 million is expected to be funded during the first year to cover certain social bonus payments and to establish our work program guarantees, such guarantees to be drawn against over the five year exploration period. These expenditures are not included in the range set forth above. See "Risk Factors—We will not have a license for Block 20 offshore Angola and we will not be able to commence our exploration, development and production operations on Block 20 until our Production Sharing Agreement for Block 20 is successfully negotiated and executed." We expect that our existing cash on hand will be sufficient to fund our planned exploration and appraisal drilling program, including any expenditures relating to Block 20 offshore Angola, at least through the end of 2011. However, we may require additional funds earlier than we currently expect in order to execute our strategy as planned. We may seek additional funding through asset sales, farm-out arrangements and 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. If we are unable to obtain funding on a timely basis or on acceptable terms, we may be required to significantly curtail one or more of our exploration and appraisal drilling programs. We also could be required to seek funds through arrangements with collaborators or others that may require us to relinquish rights to some of our prospects which we would otherwise develop on our own, or with a majority working interest.

Cash Flows

	Year Ended December 31.		
	2010	2009	2008
	($ in thousands)		
Net cash provided by (used in):			
Operating Activities	$(133,264)	$ (75,486)	$ (48,420)
Investing Activities	(758,372)	87,123	(608,876)
Financing Activities	101,256	1,076,360	566,453

Operating activities. The increase in net cash used in 2010 was attributable to the increase in cash payments for seismic data acquisition for the U.S. Gulf of Mexico and offshore West Africa, force majeure expenses relating to the Deepwater Horizon incident and expenses incurred relating to mobilization of the Ensco 8503 drilling rig offset by receipt of approximately $15.1 million from our partner in West Africa for reimbursement of past seismic data expenditures and overhead charges. The net cash used in operating activities during 2009 was primarily related to cash payments for seismic expenses relating to the drilling of the Shenandoah #1, Heidelberg #1, Ligurian #1 and Criollo #1 exploratory wells offset by receipt of approximately $10.2 million from a partner in the U.S. Gulf of Mexico for reimbursement of past seismic data expenditures. The majority of the net cash used in operating activities during 2008 was attributable to expenditures for seismic data.

Investing activities. Net cash used in investing activities in 2010 was approximately $758.4 million compared with net cash provided by investing activities of approximately $87.1 million and net cash used in investing activities of approximately $608.9 million in 2009 and 2008, respectively. The increase in net cash used in 2010 was primary attributable to the investment of the net proceeds from our IPO in certain held-to-maturity securities. The decrease in net cash used in 2009 was primarily attributed to proceeds received in 2009 totaling approximately $333.3 million for sale of leasehold interests in the

U.S. Gulf of Mexico offset by an increase in restricted cash to guarantee the Ensco 8503 rig contract and an increase in exploratory well investment. In addition, net cash used in investing activities in 2008 was primarily for acquisition of leasehold interests in the U.S. Gulf of Mexico.

Financing activities. Net cash provided by financing activities in 2010 was approximately $101.3 million compared with net cash provided by financing activities of approximately $1.0 billion and $566.4 million in 2009 and 2008, respectively. The decrease in net cash provided by financing activities in 2010 was primarily attributed to the IPO in December 2009. In January, 2010, we received net proceeds of approximately $101.3 million from the underwriters' exercise of the over-allotment option. The increase in net cash provided by financing activities in 2009 was attributed to cash received from Cobalt International Energy, L.P.'s Class A limited partnership interest holders and the net proceeds of approximately $856.1 million from the initial public offering and sale of 3,125,000 shares pursuant to Regulation S, which closed on December 21, 2009. The net cash provided in 2008 represents the cash of $566.5 million received from Cobalt International Energy, L.P.'s Class A limited partnership interest holders.

Contractual Obligations

As of December 31, 2010, our contractual obligations were limited to payments to be made in connection with the leases related to the Ensco 8503 and Diamond Offshore Ocean Confidence drilling rigs, office lease payments and lease rental payments for exploration rights from the BOEMRE for further exploration in the western and central U.S. Gulf of Mexico. The following table summarizes by period the payments due for our estimated contractual obligations as of December 31, 2010:

	Payments Due By Year						
	2011	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total**
			($ in thousands)				
Drilling Rig Contracts	$165,075	$186,150	$93,075	$ —	$ —	$ —	$444,300
Operating Leases	613	240	—	—	—	—	853
Lease Rentals	5,967	5,911	5,812	4,973	4,608	10,071	37,342
Total	**$171,655**	**$192,301**	**$98,887**	**$4,973**	**$4,608**	**$10,071**	**$482,495**

In the future, we may be party to the following contractual arrangements, which will subject us to further contractual obligations:

- credit facilities;
- contracts for the lease of 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, 2010, 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 2 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. As of December 31, 2010, 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 and typically exceed federally insured limits. We periodically assess the financial condition of the institutions where these funds are held and the credit ratings of the issuers of these instruments and believe that the credit risk is minimal.

Investments. We adopted a policy on accounting for our investments, which consist entirely of debt securities, based on the guidance of Accounting Standards Codification (ASC) No. 320, *Accounting for Certain Investments in Debt and Equity Securities.* The debt securities are carried at amortized costs and classified as held-to-maturity as we have the 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.

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 properties. 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. Unproved leasehold costs are capitalized and are not amortized, pending an evaluation of their exploration potential. Signifcant 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 exploratory 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 based on their respective useful lives.

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

Income Taxes. Prior to December 15, 2009, no provision for U.S. federal income taxes related to our operations was included in the accompanying financial statements. As a partnership, we were not subject to federal or state income tax, and the tax effect of our activities accrued to the partners. The Partnership had obligations associated with providing certain tax-related information to the partners and registrations and filings with applicable governmental taxing authorities.

Effective December 15, 2009, we began using the liability method of accounting for income taxes in accordance with FASB ASC No. 740, *Income Taxes"* as clarified by FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement No. 109, "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 will 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 (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, 2010, we do not have any proved reserves. Should proved reserves be found in the future, estimated reserve quantities and future cash flows will be 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. We currently do not have any oil and natural gas production. Should such production occur in the future, we expect to have significant obligations under our lease agreements and federal regulation to remove our 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. Pursuant to the FASB ASC No. 410-20, *"Assets Retirement Obligations"*, we are required to 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 representing asset retirement costs on our balance sheet. 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 our oil and natural gas property asset balance. Increases in the discounted abandonment liability and related oil and natural gas assets resulting from the passage of time will be reflected as additional accretion and depreciation expense 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 nonvested restricted shares outstanding during the periods presented, unless their effect is 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 using the Black-Scholes 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, 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 and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view 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, if and when we commence production, 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.

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, 2010, 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, 2010.

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 has been no change in our internal control over financial reporting during the fourth quarter ended December 31, 2010, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. *Other Information*

None.

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 "2011 Proxy Statement") for our annual meeting of stockholders to be held on April 28, 2011, 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 2011 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 2011 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 2011 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 2011 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.
"Appraisal well"	A well drilled after an exploratory 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.
"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.
"Blowouts"	Blowout is the uncontrolled release of a formation fluid, usually gas, from a well being drilled, typically for petroleum production. A blowout is caused when a combination of well control systems fail primarily drilling mud hydrostatics, and formation pore pressure is greater than the wellbore pressure at depth.
"Closure"	A trapping configuration.
"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"	A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed the related oil and natural gas operating expenses and taxes.
"E&P"	Exploration and production.
"Exploratory 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-in"	An agreement whereby an oil company acquires a portion of the leasehold or working interest in a block from the owner of such interest in certain acreage, usually in return for cash and for taking on a portion of the drilling of one or more specific wells or other performance by the assignee as a condition of the assignment. Under a farm-in, 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.
"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.
"Gas-oil ratio"	The ratio of the volume of gas that comes out of solution from the volume of oil at standard conditions (expressed in standard cubic feet per barrel of oil); a component of hydrocarbon yield.

"Horizon"	A zone of a particular formation; that part of a formation of sufficient porosity and permeability to form a petroleum reservoir.
"Hydrocarbon yield"	The oil and natural gas that can ultimately be recovered from a volume of rock (expressed in boe per acre-foot); the primary components of which are recoverable oil and gas-oil ratio.
"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.
"Mean net pay thickness"	The mean vertical extent of the effective hydrocarbon-bearing rock (expressed in feet).
"Mean prospect area"	The mean aerial extent of a hydrocarbon-bearing rock (expressed in feet).
"Mud"	Mud is a term that is generally synonymous with drilling fluid and that encompasses most fluids used in hydrocarbon drilling operations, especially fluids that contain significant amounts of suspended solids, emulsified water or oil.
"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.
"Narrow-azimuth 3-D seismic data" . .	Seismic data acquired with receivers located in long lines that are located in line with source position. This acquisition is repeated in closely positioned parallel lines to yield 3-D seismic data coverage.
"NORM"	Naturally occurring radioactive materials.
"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).

"Pre-stack, depth-migrated seismic data processing" . . . . A type of seismic data processing used to position recorded seismic reflections into their correct subsurface location and depth.

"Probable reserves" . . . . Oil and gas whose existence is not proven by geological information but is probably present due to proximity to proved reserves and can be produced if located. Probable reserves are less accurate that proved reserves.

"Producing well" . . . . A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"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.

"Protraction area" . . . . An offshore area in the U.S. Gulf of Mexico defined by a series of blocks.

"Proved reserves" . . . . Estimated quantities of crude oil, natural gas, NGL's 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).

"Recoverable oil" . . . . The amount of oil that can ultimately be recovered from a volume of rock (expressed in barrels of oil per acre-foot); a component of hydrocarbon yield.

"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.

"Secondary recovery"	An artificial method or process used to restore or increase production from a reservoir after the primary production by the natural producing mechanism and reservoir pressure has experienced partial depletion. Gas injection and waterflooding are examples of this technique.
"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.
"Wave equation, pre-stack, depth-migrated seismic data processing"	A type of seismic data processing.
"Wide-azimuth seismic data"	Seismic data acquired with receivers located in long lines that have sources positioned in line with additional sources positioned at large lateral offsets. This acquisition is repeated in closely positioned parallel lines to yield 3-D seismic data coverage with increased azimuths of energy penetration.
"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. (pka Cobalt International Energy, L.P.)

(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
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))
10.1†	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))
10.2†	Severance Agreement, dated October 23, 2009, among the Company, the Partnership and Samuel H. Gillespie (incorporated by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.3†	Employment Agreement, dated October 23, 2009, among the Company, the Partnership and Rodney L. Gray (incorporated by reference to Exhibit 10.3 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.4†	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))
10.5†	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))
10.6†	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))
10.7	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))
10.8	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))
10.9	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))
10.10	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))

Exhibit Number	Description of Document
10.11	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))
10.12	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))
10.13	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))
10.14†	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))
10.15†	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))
10.16†	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))
10.17†	Long Term Incentive Plan of the Company (incorporated by reference to Exhibit 99.1 to the Company's Registration Statement on Form S-8 filed December 21, 2009 (File No. 333-163883))
10.18†	Deferred Compensation Plan of the Partnership (incorporated by reference to Exhibit 99.2 to the Company's Registration Statement on Form S-8 filed December 21, 2009 (File No. 333-163883))
10.19†	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))
10.20†	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))
10.21†	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))
10.22†	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))
10.23	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))
10.24	Irrevocable Contract Guarantee, dated May 5, 2008, between the Partnership, Ensco Offshore Company and the Guarantors named therein (incorporated by reference to Exhibit 10.20 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))

Exhibit Number	Description of Document
10.25	Termination and Release of Irrevocable Contract Guarantee, dated December 9, 2009, between Ensco Offshore Company and the Guarantors named therein (incorporated by reference to Exhibit 10.25 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579)).
10.26†*	Form of Non-Qualified Stock Option Award Agreement
10.27†*	Form of Restricted Stock Unit Award Agreement
10.28†	Separation Agreement between Rodney L. Gray and the Company, dated June 16, 2010, (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed June 21, 2010 (File No. 001-34579)).
10.29	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)).
10.30	Special Standby Rate and Potential Suspension Agreement dated November 9, 2010 between Cobalt International Energy, L.P. and Ensco Offshore Company (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed November 12, 2010 (File No. 001-34579)).
10.31†	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)).
21.1*	List of Subsidiaries
23.1*	Consent of Ernst & Young LLP
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

* Filed 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: March 1, 2011

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)	March 1, 2011
/s/ JOHN P. WILKIRSON John P. Wilkirson	Chief Financial Officer and Executive Vice President (Principal Financial Officer and Principal Accounting Officer)	March 1, 2011
/s/ PETER R. CONEWAY Peter R. Coneway	Director	March 1, 2011
/s/ HENRY CORNELL Henry Cornell	Director	March 1, 2011
/s/ JACK E. GOLDEN Jack E. Golden	Director	March 1, 2011
/s/ N. JOHN LANCASTER N. John Lancaster	Director	March 1, 2011
/s/ JON A. MARSHALL Jon A. Marshall	Director	March 1, 2011
/s/ KENNETH W. MOORE Kenneth W. Moore	Director	March 1, 2011

Signature	Title	Date
/s/ J. HARDY MURCHISON J. Hardy Murchison	Director	March 1, 2011
/s/ KENNETH A. PONTARELLI Kenneth A. Pontarelli	Director	March 1, 2011
/s/ MYLES W. SCOGGINS Myles W. Scoggins	Director	March 1, 2011
/s/ D. JEFF VAN STEENBERGEN D. Jeff van Steenbergen	Director	March 1, 2011
/s/ MARTIN H. YOUNG, JR. Martin H. Young, Jr.	Director	March 1, 2011

(This page has been left blank intentionally.)

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 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 record 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 or overriding 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* 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, 2010. The effectiveness of our internal control over financial reporting as of December 31, 2010 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/ JOHN P. WILKIRSON
Joseph H. Bryant *Chairman of the Board of Directors* *and Chief Executive Officer*	John P. Wilkirson *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, 2010, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (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, 2010, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2010 consolidated financial statements of Cobalt International Energy, Inc. (a development stage enterprise) and our report dated March 1, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 1, 2011

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. (a development stage enterprise) (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of operations, changes in partners' capital and stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2010 and for the period November 10, 2005 (inception) through December 31, 2010. 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, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2010 and for the period November 10, 2005 (inception) through December 31, 2010. 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, 2010, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 1, 2011

Cobalt International Energy, Inc.
(a Development Stage Enterprise)
Consolidated Balance Sheets

	December 31, 2010	December 31, 2009
	($ in thousands, except per share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 302,720	$1,093,100
Joint interest and other receivables	8,237	44,753
Prepaid expenses and other current assets	9,004	9,402
Inventory	34,738	6,691
Short-term investments	534,933	—
Total current assets	889,632	1,153,946
Property, plant, and equipment:		
Oil and gas properties, successful efforts method of accounting, net of accumulated depletion of $0	462,500	470,741
Other property and equipment, net of accumulated depreciation and amortization of $2,820 and $2,033, as of December 31, 2010 and 2009, respectively	1,269	871
Total property, plant, and equipment, net	463,769	471,612
Restricted cash	338,515	186,547
Long-term investments	40,003	—
Other assets	14,524	—
Total assets	$1,746,443	$1,812,105
Liabilities and Partners' Capital/Stockholders' Equity		
Current liabilities:		
Trade and other accounts payable	$ 11,989	$ 34,966
Accrued liabilities	12,570	35,557
Total current liabilities	24,559	70,523
Other long-term obligations	2,850	—
Stockholders' Equity:		
Common stock, $0.01 par value per share; 2,000,000,000 shares authorized, 350,733,998 and 340,517,583 issued and outstanding as of December 31, 2010 and 2009, respectively	3,507	3,405
Additional paid-in capital	2,226,726	2,112,900
Accumulated deficit during the development stage	(511,199)	(374,723)
Total stockholders equity	1,719,034	1,741,582
Total liabilities and stockholders' equity	$1,746,443	$1,812,105

See accompanying notes.

Cobalt International Energy, Inc.

(a Development Stage Enterprise)

Consolidated Statements of Operations

	Year Ended December 31			For the Period November 10, 2005 (Inception) Through December 31,
	2010	2009	2008	2010
	($ in thousands except per share data)			
Oil and gas revenue	$ —	$ —	$ —	$ —
Operating costs and expenses:				
Seismic and exploration	45,030	30,666	41,274	296,601
Dry hole expense and impairment	44,178	14,486	—	58,664
General and administrative	48,063	35,996	31,271	158,850
Depreciation and amortization	787	622	683	2,820
Total operating costs and expenses	138,058	81,770	73,228	516,935
Operating income (loss)	(138,058)	(81,770)	(73,228)	(516,935)
Other income (expense):				
Interest income, net	1,582	513	1,632	5,736
Total other income (expense)	1,582	513	1,632	5,736
Net income (loss) before income tax	(136,476)	(81,257)	(71,596)	(511,199)
Income tax expense	—	—	—	—
Net income (loss)	$(136,476)	$(81,257)	$(71,596)	$(511,199)
Basic and diluted income (loss) per share	$ (0.39)			
Pro forma basic and diluted income (loss) per share (unaudited)		$ (0.33)		

See accompanying notes.

Cobalt International Energy, Inc.
(a Development Stage Enterprise)
Consolidated Statements of Changes in Partners' Capital and Stockholders' Equity

	General Partner	Class A Limited Partners	Class B Limited Partners	Class C Limited Partners	Common Stock	Additional Paid-in Capital	Accumulated Deficit During Development Stage	Total
				($ in thousands)				
Balance, November 10, 2005 (inception)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Class A limited partners' contributions	—	3,000	—	—	—	—	—	3,000
Class B limited partners' equity compensation	—	—	142	—	—	—	—	142
Net income (loss)	—	—	—	—	—	—	(1,389)	(1,389)
Balance, December 31, 2005	—	3,000	142	—	—	—	(1,389)	1,753
Class A limited partners' contributions	—	154,984	—	—	—	—	—	154,984
Class B limited partners' equity compensation	—	—	1,350	—	—	—	—	1,350
Net income (loss)	—	—	—	—	—	—	(111,527)	(111,527)
Balance, December 31, 2006	—	157,984	1,492	—	—	—	(112,916)	46,560
Class A limited partners' contributions	—	305,135	—	—	—	—	—	305,135
Class B limited partners' equity compensation	—	—	1,132	—	—	—	—	1,132
Net income (loss)	—	—	—	—	—	—	(108,954)	(108,954)
Balance, December 31, 2007	—	463,119	2,624	—	—	—	(221,870)	243,873
Class A limited partners' contributions	—	566,453	—	—	—	—	—	566,453
Class B limited partners' equity compensation	—	—	1,741	—	—	—	—	1,741
Net income (loss)	—	—	—	—	—	—	(71,596)	(71,596)
Balance, December 31, 2008	—	1,029,572	4,365	—	—	—	(293,466)	740,471
Class A limited partners' contributions	—	227,166	—	—	—	—	—	227,166
Class B and C limited partners' equity compensation	—	—	2,619	734	—	—	—	3,353
Common stock issued upon corporate reorganization	—	(1,256,738)	(6,984)	(734)	2,743	1,261,713	—	—
Equity based compensation	—	—	—	—	—	2,402	—	2,402
Common stock issued at initial public offering, net of offering costs	—	—	—	—	630	806,629	—	807,259
Common stock issued at private placement	—	—	—	—	32	42,156	—	42,188
Net income (loss)	—	—	—	—	—	—	(81,257)	(81,257)
Balance, December 31, 2009	—	—	—	—	3,405	2,112,900	(374,723)	1,741,582
Common stock issued at the closing of the over-allotment portion of initial public offering, net of offering costs	—	—	—	—	80	101,176	—	101,256
Common stock issued for vested restricted stock	—	—	—	—	22	(22)	—	—
Equity based compensation	—	—	—	—	—	12,672	—	12,672
Net income (loss)	—	—	—	—	—	—	(136,476)	(136,476)
Balance, December 31, 2010	$ —	$ —	$ —	$ —	$3,507	$2,226,726	$(511,199)	$1,719,034

See accompanying notes.

Cobalt International Energy, Inc.
(a Development Stage Enterprise)
Consolidated Statements of Cash Flows

	Year Ended December 31 2010	2009	2008	For the Period November 10, 2005 (Inception) Through December 31, 2010
	($ In thousands)			
Cash flows provided from operating activities				
Net income (loss)	$ (136,476)	$ (81,257)	$ (71,596)	$ (511,199)
Adjustments to reconcile net loss to net cash used in operating activities:				
Depreciation and amortization	787	622	683	2,820
Dry hole expense and impairment of unproved properties	44,178	14,736	—	58,915
Equity based compensation	12,672	5,755	1,741	22,792
Amortization of premium (accretion of discount) on investment securities	1,608	—	—	1,608
Other	—	253	—	557
Changes in operating assets and liabilities:				
Joint interest and other receivables	31,266	(38,967)	591	(14,576)
Inventory	(28,047)	4,981	(11,673)	(34,738)
Prepaid expense and other assets	(14,126)	(3,373)	28,940	(20,680)
Trade and other accounts payable	(22,977)	16,314	5,190	11,976
Accrued liabilities and other	(22,149)	5,450	(2,296)	16,899
Net cash provided by (used in) operating activities	(133,264)	(75,486)	(48,420)	(465,626)
Cash flows from investing activities				
Capital expenditures for oil and gas properties	(1,746)	(14,250)	(568,860)	(704,107)
Capital expenditures for other property and equipment	(1,185)	(537)	(788)	(4,074)
Exploratory wells drilling in process	(32,585)	(45,424)	(41,207)	(154,298)
Proceeds from sale of oil and gas properties	5,656	333,346	1,995	339,001
Increase in restricted cash	(151,527)	(186,012)	(16)	(338,074)
Proceeds from maturity of investment securities	224,985	—	—	224,985
Purchase of investment securities	(801,970)	—	—	(801,970)
Net cash provided by (used in) investing activities	(758,372)	87,123	(608,876)	(1,438,537)
Cash flows from financing activities				
Capital contributions—Class A limited partners	—	226,913	566,453	1,256,180
Proceeds from initial public offering, net of costs	—	807,259	—	807,259
Proceeds from private placement, net of costs	—	42,188	—	42,188
Proceeds from over-allotment portion of initial public offering, net of costs	101,256	—	—	101,256
Net cash provided by (used in) financing activities	101,256	1,076,360	566,453	2,206,883
Net increase (decrease) in cash and cash equivalents	(790,380)	1,087,997	(90,843)	302,720
Cash and cash equivalents, beginning of period	1,093,100	5,103	95,946	—
Cash and cash equivalents, end of period	$ 302,720	$1,093,100	$ 5,103	$ 302,720

See accompanying notes.

Cobalt International Energy, Inc.

(a Development Stage Enterprise)

Notes to Consolidated Financial Statements

December 31, 2010 and 2009

1. Organization and Operations

Organization

Cobalt International Energy, Inc. (the "Company") was incorporated pursuant to the laws of the State of Delaware in August, 2009 to become a holding company for Cobalt International Energy, L.P. (the "Partnership"). The Partnership is a Delaware limited partnership formed on November 10, 2005, by funds affiliated with Goldman, Sachs & Co., Riverstone Holdings LLC and The Carlyle Group as well as members of the Partnership's management team, collectively constituting Class A limited partners. In 2006, funds affiliated with KERN Partners Ltd. and certain limited partners in such funds affiliated with KERN Partners Ltd, were admitted as a Class A limited partner. In 2007, First Reserve Corporation and Four Winds Consulting were admitted as Class A limited partners.

A corporate reorganization occurred concurrently with the completion of the initial public offering ("IPO") on December 15, 2009. All the outstanding interests of the Partnership were exchanged for 283,200,000 shares of the Company's common stock and as a result the Partnership became wholly-owned by the Company. The shares of CIP GP Corp., the general partner of the Partnership were contributed by certain of the Class A limited partners holding such shares to the Company for no consideration. Prior to reorganization, the Company was not subject to federal or state income taxes. Upon completion of the corporate reorganization, the Company became subject to federal and state income taxes.

On December 21, 2009 the Company closed its IPO with the issuance of 63,000,000 shares of common stock from the public offering and 3,125,000 of shares issued in a private placement at a price of $13.50 per share. On January 7, 2010, the Company closed the sale of an additional 7,978,000 shares of its common stock at the public offering price of $13.50 per share pursuant to the exercise of the over-allotment option by the underwriters of the IPO. The proceeds received of approximately $1.0 billion will be used to fund the offering expenses and the Company's drilling and exploration program.

Operations

The Company is an independent, oil-focused exploration and production company with a current focus in the deepwater U.S. Gulf of Mexico and offshore Angola and Gabon in West Africa. The terms "Company," "Cobalt," "we," "us," "our," "ours," and similar terms refer to Cobalt International Energy, Inc. unless the context indicates otherwise.

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 massive oil spill. Hydrocarbons discharged continuously from the well since the time of this disaster until July 15, 2010 when a capping mechanism temporarily stopped the flow of hydrocarbons and until September 19, 2010 when efforts to permanently stop the flow of hydrocarbons from the well were successful. Although the Company has no economic interest in this well or the Deepwater Horizon, all of the Company's and its partners' plans for exploration and appraisal drilling activities in the U.S. Gulf of Mexico were suspended and continue to be significantly delayed as a result of the response by the U.S. government and its regulatory agencies to the Deepwater Horizon incident.

1. Organization and Operations (Continued)

The Company does not know when it will be able to resume drilling operations in the U.S. Gulf of Mexico or at what cost. The uncertainty surrounding the timing and cost of the Company's drilling activities in the U.S. Gulf of Mexico is primarily the result of (i) newly issued regulations by the Department of the Interior ("DOI") and the DOI's Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"), (ii) ongoing clarifications and interpretive guidance often in the form of a Notice to Lessees ("NTL") issued by the DOI and the BOEMRE relating to these newly issued regulations as well as with respect to existing regulations, (iii) the Company's continuing compliance efforts relating to these regulations, clarifications and guidance, (iv) the uncertainty as to the ability of the BOEMRE to timely review submissions and issue drilling permits, (v) the general uncertainty regarding additional regulation of the oil and gas industry's operations in the U.S. Gulf of Mexico and (vi) ongoing and potential third party legal challenges to industry drilling operations in the U.S. Gulf of Mexico.

The successful execution of the Company's U.S. Gulf of Mexico business plan depends on its ability to continue its exploration and appraisal efforts. Given the current restrictions, potential future restrictions and the uncertainty surrounding the availability of any exceptions to any restrictions, the Company cannot predict when it will be able to continue its exploratory and appraisal program in the U.S. Gulf of Mexico. A prolonged suspension of or delay in the Company's drilling operations would adversely affect its business, financial position or future results of operations.

As of December 31, 2010, the Company had no proved oil and gas reserves.

Business Relationships

TOTAL Alliance

On April 6, 2009, the Company announced a long-term alliance with TOTAL E&P USA, Inc. ("TOTAL") in which, through a series of transactions, the Company combined its respective U.S. Gulf of Mexico exploratory lease inventory (which excludes the Heidelberg portion of its Ligurian/Heidelberg prospect, its Shenandoah prospect, and all developed or producing properties held by TOTAL in the U.S. Gulf of Mexico) through the exchange of a 40% interest in its leases for a 60% interest in TOTAL's leases, resulting in a current combined alliance portfolio covering 224 blocks. The Company will act as operator on behalf of the alliance through the exploration and appraisal phases of development. As part of the alliance, TOTAL committed, among other things, to (i) provide a 5th generation deepwater rig to drill a mandatory five-well program on the Company's existing operated blocks, (ii) pay up to $300 million to carry a substantial share of the Company's costs with respect to this five-well program (above the amounts TOTAL is obligated to pay as owner of a 40% interest), (iii) pay an initial amount of approximately $280 million primarily as reimbursement of the Company's share of historical costs in its contributed properties and consideration under purchase and sale agreements, (iv) pay 40% of the general and administrative costs relating to the Company's operations in the U.S. Gulf of Mexico during the 10-year alliance term, and (v) award the Company up to $180 million based on the success of the alliance's initial five-well program, in all cases subject to certain conditions and limitations. The exchange transactions on the leases resulted in no gain or loss to the Company. Additionally, as part of the alliance, TOTAL and the Company formed a U.S. Gulf of

1. Organization and Operations (Continued)

Mexico-wide area of mutual interest, whereby each party has the right to participate in any oil and natural gas lease interest acquired by the other party within this area. As of December 31, 2010, approximately $196 million of the $300 million that Total is obligated to carry the Company remains available to it, as does the potential award of up to $180 million based on the success of the alliance.

Sonangol Partnership

On April 22, 2009, the Company announced a partnership in the U.S. Gulf of Mexico with the national oil company of Angola, Sociedade Nacional de Combustíveis de Angola—Empresa Pública ("Sonangol"), whereby Sonangol acquired a 25% non-operated interest of the Company's pre-TOTAL alliance interests in 11 of the Company's U.S. Gulf of Mexico leases. The price Sonangol paid the Company for this interest was calculated using the price the Company paid for such leases plus $10 million to cover the Company's historical seismic and exploration costs. Sonangol has since acquired a 15% non-operated interest in four additional U.S. Gulf of Mexico leases pursuant to this partnership, bringing the total partnership portfolio to 15 U.S. Gulf of Mexico leases. This transaction resulted in no gain or loss to the Company. This transaction is notable as it represents Sonangol's initial entry into the North American exploration and production sector.

Sonangol Risk Services Agreements

On February 24, 2010, the Company executed Risk Services Agreements (the "RSAs") for Blocks 9 and 21 offshore Angola with Sonangol, as well as Sonangol Pesquisa e Produção, S.A., Nazaki Oil and Gáz, S.A. ("Nazaki") and Alper Oil, Limitada. The RSAs govern the Company's 40% interest in and operatorship of Blocks 9 and 21 offshore Angola and form the basis of its exploration, development and production operations on these blocks. In conjunction with the RSAs, the Company also obtained written approval from Sonangol dated March 3, 2010 to reimburse the Company for historical lease bonus, seismic costs and other technical expenditures incurred up to the date of the RSA on Blocks 9 and 21 offshore Angola as pre-RSA expenditures up to $85 million in the aggregate or $32 million net. As a result, Nazaki reimbursed the Company for its share of the leasehold bonus and related pre-RSA expenditures incurred on these blocks totaling $32 million through December 31, 2010. The $32 million reimbursement included $24.3 million for seismic expenses, $5.3 million for leasehold bonuses, and $2.4 million for other technical services. The execution of these agreements was a key milestone that allows for the commencement of the Company's offshore Angola drilling program, currently planned to begin in 2011.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements include the financial statements of Cobalt International Energy, Inc. and all of its wholly owned subsidiaries. All significant intercompany transactions and amounts have been eliminated for all years presented. Because the Company is a development stage enterprise, it has presented its financial statements in accordance with FASB Accounting Standards Codification (ASC) No. 915 *"Development Stage Entities."*

2. Summary of Significant Accounting Policies (Continued)

At December 31, 2010, the accompanying consolidated financial statements include the accounts of Cobalt and its wholly-owned subsidiary, Cobalt International Energy, L.P. ("Partnership"). Prior to the effective date of the corporate reorganization, both entities were under common control arising from common direct or indirect ownership of each. The transfer of the Partnerships interests to Cobalt represented a reorganization of entities under common control and was accounted for at historical cost. *See Note 1.*

Reclassifications

Certain reclassifications have been made to prior periods' financial statements to conform to the current presentation.

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 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 (c) assumptions used in impairment testing. Although the Company believes these estimates are reasonable, actual results could differ from these estimates.

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, 2010 and 2009, no revenues have been recognized in these consolidated financial statements.

Cash and Cash Equivalents

Cash and cash equivalents consist of demand deposits and funds invested in highly liquid instruments with original maturities of three months or less and typically exceed federally insured limits. The Company periodically assesses the financial condition of the institutions where these funds

2. Summary of Significant Accounting Policies (Continued)

are held and believes that the credit risk is minimal. As of December 31, 2010 and 2009, cash and cash equivalents consisted of the following:

	December 31, 2010	December 31, 2009
	(in thousands)	
Cash at banks	$ 10,327	$ 186,867
Money market funds	59,792	906,233
Held-to-maturity securities(1)	232,601	—
	$302,720	$1,093,100

(1) These securities mature within 90 days from date of purchase.

Restricted Cash

Restricted cash consisted of the following:

	December 31, 2010	December 31, 2009
	(in thousands)	
Ensco 8503 escrow account(1)	$186,184	$186,006
Collateral on Letters of Credit for Angola(2)	151,615	—
Other vendor restricted deposits	716	541
	$338,515	$186,547

(1) The $186.0 million was held in an escrow account established in December 2009 as a guarantee of performance to Ensco plc for the Ensco 8503 rig contract. During the year ended December 31, 2010, this escrow fund was invested in U.S. Treasury bills, purchased at a discount, resulting in net carrying value of $186.2 million as of December 31, 2010. The contractual maturities of these U.S. Treasury bills are within one year.

(2) The $151.3 million was held in a collateral account established in March 2010 as collateral for letters of credit issued in support of the Company's contractually agreed work program obligations in Angola. In April, 2010, the funds in this collateral account were invested in U.S. Treasury bills, purchased at a discount, resulting in a net carrying value of $151.6 million as of December 31, 2010. The contractual maturities of these U.S. Treasury bills are within one year.

Investments

In 2010, the Company adopted a policy on accounting for its investments, which consist entirely of debt securities, based on the guidance of Accounting Standards Codification No. 320, *Accounting for Certain Investments in Debt and Equity 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

2. Summary of Significant Accounting Policies (Continued)

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 costs 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, 2010. Income related to these securities is reported as a component of interest income in the Company's consolidated statement of operations. *See Note 5—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. For the year ended December 31, 2010, the Company has no OTTI in its debt securities.

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. As of December 31, 2010, the balance due from the Company's joint interest partners in the U.S. Gulf of Mexico and West Africa was $4.4 million and represents amounts due for seismic expenditures and reimbursable overhead charges. These 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. 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 and developmental dry holes are capitalized and amortized over the proved developed reserves on a units-of-production basis. 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 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 exploratory 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 based on their respective useful lives.

2. Summary of Significant Accounting Policies (Continued)

Asset Retirement Obligations

The Company currently does not have any oil and natural gas production. Should such production occur in the future, 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. Pursuant to the FASB ASC No. 410-20, "*Assets Retirement Obligations.*" The Company is required to record 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 representing asset retirement costs on its balance sheet. 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 and related oil and natural gas assets resulting from the passage of time will be reflected as additional accretion and depreciation expense in the consolidated statements of operations.

Inventory

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

Income Taxes

Prior to December 15, 2009, no provision for U.S. federal income taxes related to the Company's operations was included in the accompanying financial statements. As a partnership, the Partnership was not subject to federal or state income tax, and the tax effect of its activities accrued to the partners. The Partnership had obligations associated with providing certain tax-related information to the partners and registrations and filings with applicable governmental taxing authorities.

2. Summary of Significant Accounting Policies (Continued)

Effective December 15, 2009, the Company applied the liability method of accounting for income taxes in accordance with FASB ASC No. 740, *Income Taxes"* as clarified by FASB Interpretation No. 48 ("FIN 48"), *Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement No. 109, "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 is in development stage 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 to its net deferred tax assets. *See Note 15.*

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, 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 13.*

Income (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. Diluted income (loss) per share incorporate the potential dilutive impact of nonvested restricted shares outstanding during the periods presented, unless their effect is anti-dilutive. For the year ended December 31, 2010, 6,956,814 shares of non-vested restricted stock, stock options and performance-based awards were excluded from diluted income (loss) because they were anti-dilutive. *See Note 15.*

Pro forma basic income (loss) per share was calculated by dividing pro forma net income or loss applicable to common shares by the pro forma weighted average number of common shares outstanding during the year ended December 31, 2009. Pro forma net income or loss applicable to common shares reflects net income (loss) as reported and gives effect to (i) an adjustment for income taxes as if the Company was subject to taxation for the entire period and (ii) an adjustment to remove management fees paid to the Partnership's former private equity owners that terminated at the time of the IPO. The calculation of pro forma diluted income (loss) per share should include the potential dilutive impact of nonvested restricted shares outstanding during the year, unless their effect is anti-dilutive. Pro forma nonvested restricted stock awards of 8,015,041 shares for the year ended December 31, 2009 were excluded from the pro forma diluted income (loss) per share because they are anti-dilutive.

2. Summary of Significant Accounting Policies (Continued)

The pro forma weighted average shares outstanding used in the computation of pro forma basic and diluted income (loss) per share for the year ended December 31, 2009 have been computed taking into account (1) the conversion ratio at the time of the IPO of all partnership units into shares of common stock, including vested shares of restricted stock, as if the conversion occurred as of the beginning of the period and (2) the 66,125,000 shares issued by the Company in the IPO, which included 3,125,000 shares sold by the Company in a concurrent private offering pursuant to Regulation S.

Operating Costs and Expenses

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

3. Fair Value of Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, joint interest and other receivables, investments and restricted deposits. The fair value of these instruments approximates carrying values due to their short-term duration. *See Note 2—Restricted Deposits and Note 6—Investments,* for a discussion of the carrying value and fair value of the Company's investments in held-to-maturity securities.

4. Prepaid Expenses and Other Current Assets

Prepaid expenses include the prepaid and unamortized portion of payments made for software licenses, related maintenance fees, and insurance. Other current assets include short-term deposits. As of December 31, 2010 and 2009, prepaid expenses and other current assets were $9.0 million and $9.4 million, respectively.

5. Investments

The Company's investments in held-to-maturity securities which are stated at amortized cost, the approximate fair market value of which were as follows at December 31, 2010:

	December 31, 2010
	(in thousands)
US Treasury securities	$ 604,035
US corporate securities	180,191
Commercial paper	282,039
U.S. government agency securities	60,003
Municipal bonds	19,068
Total	$1,145,336

5. Investments (Continued)

The Company's held-to-maturity securities were included in the following captions in the Company's balance sheets:

	December 31, 2010
	(in thousands)
Cash and cash equivalents	$ 232,601
Short-term investments	534,933
Restricted cash	337,799
Long-term investments	40,003
Total	$1,145,336

There were no held-to-maturity securities as of December 31, 2009.

The contractual maturities of these held-to-maturity securities at December 31, 2010 were as follows:

	Amortized Cost	Fair Value
	($ in thousands)	
Within 1 year	$1,105,333	$1,105,333
After 1 year	40,003	40,003
	$1,145,336	$1,145,336

6. Related Parties

The Limited Partnership Agreement (the "LPA") governing Cobalt International Energy, L.P. was entered into on November 10, 2005 and amended and restated as of December 23, 2005, September 30, 2006, October 10, 2006, August 30, 2007, December 10, 2007, December 12, 2008 and February 6, 2009. The LPA provided for an annual monitoring fee for funds affiliated with First Reserve Corporation, Goldman, Sachs & Co., Riverstone Holdings LLC, The Carlyle Group and KERN Partners Ltd, and certain limited partners in such funds affiliated with KERN Partners Ltd. (or their respective affiliates). The monitoring fee was allocated pro rata in accordance with each fund's Class A commitment amount and the number of days each applicable fund was a Class A limited partner. The Partnership recorded $0, $2.6 million and $1.1 million, and $6.0 million of monitoring fees for the years ended December 31, 2010, 2009 and 2008, and for the period November 10, 2005 (Inception) through December 31, 2010, respectively. These amounts are included in general and administrative expense in the accompanying consolidated statements of operations. Additionally, the Company reimbursed certain Class A limited partners for legal, travel and administrative expenses during the years ended December 31, 2010, 2009 and 2008, and for the period November 10, 2005 (Inception) through December 31, 2010 of $0, $0.3 million, $0.6 million, and $1.7 million, respectively. Pursuant to the terms of the corporate reorganization which occurred on December 15, 2009, the rights to receive monitoring fees and reimbursement of expenses by the Class A limited partners were terminated.

7. 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, 2010	December 31, 2009
		($ in thousands)	
Unproved oil and gas properties		$355,619	$363,515
Exploratory wells in process		106,881	107,226
Computer equipment and software	3	2,300	1,300
Office equipment and furniture	3	1,047	995
Vehicles	3	76	—
Leasehold improvements	3	666	609
		466,589	473,645
Less: accumulated depreciation and amortization		(2,820)	(2,033)
Property, plant, and equipment, net		$463,769	$471,612

The Company recorded $0.8 million, $0.6 million, $0.7 million and $2.8 million of depreciation and amortization expense for the years ended December 31, 2010, 2009 and 2008, and for the period November 10, 2005 (inception) through December 31, 2010, respectively.

Acquisition costs of unproved leasehold 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. Significant unproved leases are assessed individually for impairment based on the Company's current exploration plans and an allowance is provided if impairment is indicated. Unproved leasehold costs for properties that are individually less than $1.0 million in carrying value are amortized on a group basis over the average terms of the leases, at rates that provide for full amortization of leases upon lease expiration. These leases have expiration dates ranging from 2011 through 2020. As of December 31, 2010, the balance for unproved leaseholds that were individually less than $1.0 million was $65.1 million. For the years ended December 31, 2010 and for the period November 10, 2005 (inception) through December 31, 2010, the Company recorded $9.1 million as amortized expense on its unproved leasehold properties. No such amortized expense were recorded for the years ended December 31, 2009 and 2008.

Capitalized Exploratory Well Costs

If an exploratory well provides evidence as to the existence of sufficient quantities of hydrocarbons to justify potential completion as a producing well, 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

7. Property, Plant, and Equipment (Continued)

the discovery is sufficient to support an economic development plan and (iv) the requirement for government sanctioning in international location before proceeding with development activities.

The following table reflects the Company's net changes in and the cumulative costs of capitalized exploratory well costs (excluding any related leasehold costs):

	Year Ended December 31, 2010	2009	2008
	($ in thousands)		
U.S. Gulf of Mexico:			
Beginning of year	$107,226	$ 71,662	$ —
Addition to capitalized exploratory well cost pending determination of proved reserves			
Shenandoah #1 Exploratory Well	176	9,935	59,410
Heidelberg #1 Exploratory Well	8	7,980	12,252
Heidelberg #2 Appraisal Well	10,854	276	—
Ligurian #1 Exploratory Well	86	18,589	—
Criollo #1 Exploratory Well	8,171	13,268	—
Firefox #1 Exploratory Well	12,463	—	
Other pre-spud costs	2,839	2	—
Reclassifications to wells, facilities, and equipment based on determination of proved reserves	—	—	—
Amounts charged to expense	(34,942)	(14,486)	—
End of year	$106,881	$107,226	$71,662

	Year Drilled	December 31, 2010	2009
		($ in thousands)	
Cumulative costs:			
Shenandoah #1 Exploratory Well	2008	$ 69,521	$ 69,345
Heidelberg #1 Exploratory Well	2008	20,240	20,232
Heidelberg #2 Appraisal Well	2010	—	276
Ligurian #1 Exploratory Well	2009	8,100	8,093
Criollo #1 Exploratory Well	2009	9,020	9,278
Firefox #1 Exploratory Well	2010	—	—
Other Pre-spud costs		—	2
		$106,881	$107,226
Exploratory Well costs capitalized for a period greater than one year after completion of drilling at December 31, 2010 (included in table above)		$106,881	$ 89,761

7. Property, Plant, and Equipment (Continued)

Capitalized exploratory well costs that have been suspended longer than one year are associated with the Shenandoah #1 and Heidelberg #1 projects. These exploratory well costs are suspended 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 projects 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 projects, the associated costs will be expensed at that time.

As of December 31, 2010, no exploratory wells have been drilled by the Company in offshore Angola or Gabon.

8. Other Assets

As of December 31, 2010, costs associated with the mobilization of the Ensco 8530 drilling rig were deferred in other assets. The rig is currently assigned to another company by its owner until mid 2011. Upon completion of this assignment, the Company will amortize these costs to respective exploratory wells as and when the rig is used for drilling activities over the initial two-year term of the drilling contract. These costs will be expensed or capitalized to oil and gas properties as exploratory drilling costs, depending on the drilling results.

9. Other Long-Term Obligations

The Company is required to make $4.2 million of social obligation payments to Sonangol based on the terms of the RSAs as described in Note 1—Business Relationships. As of December 31, 2010, $2.9 million relates to the long-term portion of these social obligation payments to be paid over a five year period.

10. Stockholders' Equity

Upon closing of the IPO on December 15, 2009, the Company became authorized to issue 2,000,000,000 shares of common stock, $0.01 par value per share, and 200,000,000 shares of preferred stock, $0.01 par value per share. As a result of the corporate reorganization, all the outstanding partnership interests in Cobalt LP were exchanged for 283,200,000 shares of the Company's common stock, of which 274,392,583 were issued and outstanding as of December 15, 2009 and 8,015,041 were in the form of nonvested restricted shares.

On December 21, 2009, the Company issued 63,000,000 shares of its common stock through the IPO and 3,125,000 shares through a private placement at a price of $13.50 per share.

On January 7, 2010, the Company closed the sale of an additional 7,978,000 shares of its common stock at the public offering price of $13.50 per share pursuant to the exercise over-allotment option by the underwriters of the IPO.

11. Seismic and Exploration Expenses

Seismic and exploration expenses consisted of the following:

	For Year Ended December 31, 2010	2009	2008	For the Period November 10, 2005 (Inception) through December 31, 2010
	($ in thousands)			
Seismic costs	$ 39,748	$ 34,551	$36,280	$286,613
Seismic cost recovery(1)	(15,126)	(10,000)	—	(25,126)
Leasehold delay rentals	5,989	6,115	4,994	20,695
Force Majeure expense(2)	13,549	—	—	13,549
Drilling rig expense	870	—	—	870
	$ 45,030	$ 30,666	$41,274	$296,601

(1) These amounts represent reimbursement from partners of past seismic costs incurred by the Company. *See Note 1—Business Relationships.*

(2) Expenditures resulting from suspension of drilling activities in the U.S. Gulf of Mexico as a result of the explosion and sinking of the Deepwater Horizon drilling rig in the U.S. Gulf of Mexico, the resulting oil spill and the legislative and regulatory response thereto.

12. Equity based Compensation

Under the Company's Long Term Incentive Plan ("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, 2010, approximately 9.7 million shares remain available for grant under the Incentive Plan.

On January 28, 2010, the Company adopted the Non-Employee Directors Compensation Plan (NED Plan). Under the NED Plan, the Company may issue options, restricted stock units, other stock-based award or retainer to non-employee directors. At December 31, 2010, 675,934 shares remain available for grant under the NED Plan.

In accordance with ASC No. 718, *Compensation—Stock Compensation,* 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.

12. Equity based Compensation (Continued)

Restricted Stock

Prior to the corporate reorganization which occurred December 15, 2009, the Company was organized as a partnership and governed by a limited partnership agreement (LPA). The LPA provided for the grant of Class B, C, and D partnership units to the management and employees of the Company which were subsequently converted into restricted stock as part of the corporate reorganization.

Due to the similarity of this program to a stock award, the Company accounted for the restricted stock based on ASC Topic 718 as described above. The fair value of the partnership units granted from November 10, 2005 (inception) through December 31, 2008 was determined using the income approach based on the expected probability of success in the discovery of proved reserves in oil and gas properties owned or anticipated to be owned by the Partnership. The expected value was then discounted to present value using a discount rate based on similar companies in the Partnership's stage of development and adjusted for specific partnership risks and investors' expectations. The fair value of the partnership units granted after December 31, 2008 but before the IPO date was valued at an assumed fair market value using the anticipated IPO value. For restricted stock awards without market conditions granted at the corporate reorganization and thereafter the fair value was calculated at the per share closing price as of the date of grant. For restricted stock awards with market conditions, the fair value of the awards is measured using the asset-or-nothing option pricing model.

The following table summarizes the information about the restricted stock awarded to employees for the period from the Company's corporate reorganization on December 15, 2009 to December 31, 2010 and the partnership units awarded on an equivalent share and per share price basis for the period from January 1, 2008 through the Company's corporate reorganization on December 15, 2009:

	Years Ended December 31,					
	2010		2009		2008	
	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	8,015,041	$ 7.67	9,113,772	$ 0.32	14,191,916	$0.26
Granted pre-reorganization	—	—	1,043,507	$20.86	454,742	$1.28
Granted post-reorganization	442,156	$ 9.96	3,705,425	$11.71	—	—
Vested	(2,213,277)	$ 0.51	(5,356,756)	$ 0.25	(5,167,822)	$0.25
Forfeited or expired	(673,025)	$15.35	(490,907)	$ 0.31	(365,064)	$0.31
Non-vested shares at end of year	5,570,895	$ 9.77	8,015,041	$ 7.67	9,113,772	$0.32
Weighted-average period remaining	3.3 years		3.2 years		1.3 years	
Unrecognized compensation ($ in thousands)	$ 41,599		$ 63,371		$ 2,201	

For the year ended December 31, 2010, 45,000 nonvested restricted shares held by a former officer of the Company were accounted for as vested and 585,778 nonvested restricted shares were forfeited pursuant to the terms of the Separation Agreement between the officer and the Company. The terms

12. Equity based Compensation (Continued)

of the Separation Agreement were accounted for in accordance with ASC No. 718, *Compensation—Stock Compensation* and resulted in $0.5 million recognized in stock compensation expense for the vested shares and $2.4 million recognized as a reduction to the stock compensation expense for the forfeited shares during the year ended December 31, 2010.

During the year ended December 31, 2010, the Company granted 53,121 restricted stock units to non-employee directors and also granted 24,865 shares of common stock as retainer awards to non-employee directors who elected to be compensated by stock in lieu of cash payments. As of December 31, 2010, there were 53,121 nonvested shares relating to non-employee directors and a total of $0.1 million of unrecognized compensation cost, all of which will be recognized during 2011. The weighted average fair value of these shares at grant date was $7.30. In addition, on February 4, 2010, in a private placement the Company issued 3,920 shares of common stock to a director for services rendered. These shares of common stock were not issued under the NED Plan because such plan had not yet been approved by the Company's stockholders.

Non-Qualified Stock Options

On December 3, 2010, the Company granted 1,133,960 non-qualified stock options to officers and employees with an exercise price equal to the market value of the Company's common stock at the date of grant of $12.45 per share. The non-qualified stock option awards have contractual terms of 10 years and vest ratably over a four-year period beginning on December 31, 2011. There were no non-qualified stock options granted prior to December 3, 2010.

The fair value of each stock option granted is estimated on the date of grant 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 grant date fair value per share for the year ended December 31, 2010 was $6.78 per option.

Listed below is the weighted average of each assumption based on the grants made on December 3, 2010:

Expected Term in Years	6.25
Expected Volatility	54.4%
Expected Dividends	0%
Risk-Free Interest Rate	2.7%

The Company estimates expected volatility based on an analysis of its stock price since the IPO and comparing the stock price volatility for the period from IPO date through December 3, 2010 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.

12. Equity based Compensation (Continued)

As of December 31, 2010, there were 1,133,960 shares of common stock underlying outstanding stock options. As of December 31, 2010, there was $7.6 million of total unrecognized compensation cost related to stock options, which is expected to be recognized over a weighted-average period of 4 years.

Restricted Stock Units

On December 3, 2010, the Company granted 198,838 restricted stock units to employees based on the Restricted Stock Unit (RSU) Award Agreement. Under the RSU Award Agreement the share-based payment is earned based on the number of successful wells drilled during the three year period ending December 31, 2013. The RSU award will vest 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. In no event shall the recipients 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 is calculated by the number of successful wells drilled during the respective years multiplied by vesting percentage ranging from 25% to 37.5%. No payout in the form of the RSUs will be made if the number of successful wells drilled between January 1, 2011 and December 31, 2013 divided by the total wells spud during the same period is less than 20%. The RSU Award Agreement therefore has multiple implicit service periods which are determined by and when the Company drills a successful well. The fair value of the RSUs awards is determined by the closing price of the Company's common stock at the date of grant, which was $12.45 per share, in accordance with ASC No. 718, *Compensation—Stock Compensation*. Compensation cost will be recognized as and when the performance condition is satisfied. Until such time when the Company resumes its drilling activities in the U.S. Gulf of Mexico and/or commences its drilling activities offshore Angola in 2011, the Company will be unable to determine the probability of successful wells drilled. As a result, no compensation cost was recognized for the year ended December 31, 2010 for these awards. As of December 31, 2010, unrecognized compensation cost related to restricted stock units ranged from $2.5 million to $5.0 million.

12. Equity based Compensation (Continued)

The table below summarizes the equity-based compensation costs recognized for the years ended December 31, 2010, 2009 and 2008, and for the period November 10, 2005 (inception) through December 31, 2010:

	For Year Ended December 31,			For the Period November 10, 2005 (Inception) through December 31,
	2010	2009	2008	2010
	($ in thousands)			
Restricted stock:				
Employees	$12,064	$3,927	$1,741	$20,356
Non-employee directors	507	—	—	507
Stock options:				
Employees	101	—	—	101
Restricted stock units (performance-based)	—	—	—	—
Deferred stock compensation(1)	—	1,828	—	1,828
	$12,672	$5,755	$1,741	$22,792

(1) In December 2008, the Company adopted a deferred compensation plan and provided certain executive officers the opportunity to defer under the Plan all or a portion of their salary and/or annual bonus for 2009. Amounts deferred under the Plan generally are deemed to be invested in a money market account prior to the IPO and shares of the Company's common stock following the IPO. Subject to accelerated payment under specified circumstances, the deferred amounts will be distributed to these executives in January 2012 in the form of shares of the Company's common stock. As of December 31, 2010, there were 121,637 shares under the Plan to be distributed to these executives.

13. 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 were 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. Effective January 1, 2010, the Plan was amended to discontinue the employers' matching contributions. For the years ended December 31, 2010, 2009 and 2008, and for the period November 10, 2005 (inception) through December 31, 2010, the Company recorded $0, $0.5 million, $0.5 million and $1.4 million, respectively, in benefits contributions to the Plan, which are included in the general and administration expenses.

14. Income Taxes

For the year ended December 31, 2010, the Company recorded a net deferred tax asset of $97.6 million with a corresponding full valuation allowance of $97.6 million for the net tax effects of

14. Income Taxes (Continued)

temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Prior to corporate reorganization on December 15, 2009, the Company was not subject to federal or state income taxes. Upon completion of the corporate reorganization, the Company became subject to federal and state income taxes. At the time of the corporate reorganization, the Company recorded a net deferred tax asset of $28.9 million with a corresponding full valuation allowance of $28.9 million for book/tax differences contributed to the corporation by the underlying partners.

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

	Year Ended December 31, 2010	Period from December 15-31, 2009
	($ in thousands)	
Current	$—	$—
Deferred	—	—
Total	$—	$—

The reconciliation of income taxes computed at the U.S. federal statutory tax rate to the Company's income tax expense (benefit) for the year ended December 31, 2010 and for the period from December 15, 2009 through December 31, 2009 are as follows:

	Year Ended December 31, 2010	Period from December 15-31, 2009
	($ in thousands)	
Net income (loss) as reported	$(136,476)	$(81,257)
Less: net income (loss) applicable to period before corporate reorganization	—	(46,645)
Net income (loss) applicable to period after corporate reorganization	$(136,476)	$(34,612)

	Year Ended December 31, 2010		Period from December 15-31, 2009	
	($ in thousands)			
Income tax expense (benefit) at the federal statutory rate	$(47,767)	35.00%	$(12,114)	35.00%
State income taxes, net of federal income tax benefit	(339)	0.25%	—	—
Deferred income taxes established at date of corporate reorganization	(8,735)	6.33%	(28,867)	83.40%
Other	176	0.13%	86	0.25%
Valuation allowance	56,665	41.45%	40,895	118.15%
	$ —	—	$ —	—

14. 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. The significant components of the Company's deferred tax assets and liabilities were as follows:

	As of December 31,	
	2010	2009
	($ in thousands)	
Deferred tax liabilities:		
Oil and gas properties	$ 8,084	$ 8,374
Other	666	884
Total deferred liabilities	8,750	9,258
Deferred tax assets:		
Seismic and exploration costs	$ 47,613	29,592
Stock-based compensation	5,142	877
Tax credits and NOL carry forwards	51,003	9,074
Other	2,552	10,610
Valuation allowance	(97,560)	(40,895)
Total deferred assets	8,750	9,258
Net deferred assets	$ —	$ —

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 the years ended December 31, 2010 and 2009, and for the period November 10, 2005 (Inception) through December 31, 2010.

The NOL carryforward of approximately $145.3 million as of December 31, 2010 begins to expire in 2025. The utilization of the NOL carryforwards may be limited under IRS Section 382 ownership changes.

There were no unrecognized tax benefits nor any accrued interests or penalties associated with unrecognized tax benefits as of the date of the adoption of FIN 48 and through December 31, 2010. The adoption of FIN 48 did not have an effect on the Company's consolidated financial statements based on its current income tax positions.

15. Income (Loss) Per Share

The following table presents the calculation of basic and diluted income (loss) per share and pro forma basic and diluted income (loss) per share for the years ended December 31, 2010 and 2009, respectively, as discussed further in the summary of significant accounting policies in Note 2:

	December 31, 2010	December 31, 2009
	($ in thousands except per share data)	
Net income (loss)	$ (136,476)	$ (81,257)
Income tax expense	—	—
Net income (loss)	$ (136,476)	
Pro forma income tax expense(1)(2)		—
Pro forma management fees(3)		2,872
Pro forma net income (loss)		$ (78,385)
Basic and diluted income (loss) per common share	$ (0.39)	
Weighted average common shares outstanding	349,342,050	
Pro forma basic and diluted income (loss) per share		$ (0.33)
Weighted average common shares outstanding used in pro forma basic and diluted net income (loss) per common share		236,751,219

(1) Upon completion of the Company's IPO and corporate reorganization in December, 2009, the Partnership became wholly-owned by the Company. As a result, all of the Partnership's outstanding limited partnership interests were exchanged for shares of the Company's common stock based on these interests' relative rights as set forth in the Partnership's limited partnership agreement. Additionally, the Company became subject to federal and state income taxes.

(2) 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.

(3) Upon completion of the corporate reorganization, the right of the Company's former private equity owners to receive a management fee terminated.

16. Contractual Obligations and Commitments

As of December 31, 2010, the Company's contractual obligations were limited to payments to be made in connection with the leases related to the Ensco 8503 and Diamond Offshore Ocean Confidence drilling rigs, office lease payments and lease rental payments for exploration rights from the BOEMRE for further exploration in the western and central U.S. Gulf of Mexico. The following table

16. Contractual Obligations and Commitments (Continued)

summarizes by period the payments due for the estimated contractual obligations as of December 31, 2010:

	Year Ended December 31,
	($ in thousands)
2011	$171,655
2012	192,301
2013	98,887
2014	4,973
2015	4,608
2016+	10,071

The Company recorded $6.9 million, $6.4 million, $5.4 million and $22.8 million of office and delay rental expense for the years ended December 31, 2010, 2009 and 2008, and for the period November 10, 2005 (Inception) through December 31, 2010, respectively.

17. Contingencies

The Company is not currently party to any legal proceedings. However, from time to time the Company 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.

18. Supplemental Cash Flow Information

The following reflects the Company's supplemental cash flow information:

	Years Ended December 31,			For the Period November 10, 2005 (Inception) through December 31, 2010
	2010	2009	2008	
	($ in thousands)			
Noncash additions to property, plant, and equipment relating to current liabilities and accounts payable	$2,011	$4,628	$30,455	$2,011
Amount due from Cobalt's partner in Angola for recovery of leasehold bonuses included in joint interest receivable	$ —	$5,250	$ —	$ —

19. Selected Quarterly Financial Data—Unaudited

Unaudited quarterly financial data for the years ended December 31, 2010 and 2009 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	($ in thousands)			
Year ended December 31, 2010				
Operating costs and expenses	$ 29,829	$ 41,994	$ 35,589	$ 30,645
Operating income (loss)	(29,829)	(41,994)	(35,589)	(30,645)
Net income (loss)	(29,732)	(41,766)	(35,182)	(29,796)
Basic and diluted income (loss) per common share(1)	$ (0.09)	$ (0.12)	$ (0.10)	$ (0.09)
Year ended December 31, 2009				
Operating costs and expenses	$ 11,630	$ 2,339	$ 15,116	$ 52,685
Operating income (loss)	(11,630)	(2,339)	(15,116)	(52,685)
Net income (loss)	(11,633)	(2,061)	(14,986)	(52,577)
Pro forma basic and diluted income (loss) per common share(1)(2)	$ (0.05)	$ (0.01)	$ (0.06)	$ (0.21)

(1) Totals may not add due to rounding.

(2) Pro forma basic income (loss) per share was calculated by dividing pro forma net income or loss applicable to common shares by the pro-forma weighted average number of common shares outstanding during the applicable period. See pro forma net income (loss) applicable to common shares as described in Note 2.

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

The supplementary oil and gas data that follows is presented in accordance with supplemental disclosure requirements under ASC No. 932, *"Extractive Activities—Oil and Gas"* and includes (1) capitalized costs, costs incurred and results of operations related to oil and gas producing activities, (2) net proved oil and gas reserves producing activities, (3) net proved oil and gas reserves, and (4) a standardized measure of discounted future net cash flows relating to proved oil and gas reserves. Since the Company did not have any proved reserves as of December 31, 2010 and 2009, there will be no disclosures on (2), (3) and (4) above.

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

Capitalized Costs Related to Oil and Gas Activities

	U.S. Gulf of Mexico	West Africa	Total
	($ in thousands)		
As of December 31, 2010			
Unproved properties(1)	$450,903	$20,745	$471,648
Proved properties	—	—	—
	450,903	20,745	471,648
Provision for impairments	(9,148)	—	(9,148)
Accumulated depreciation, depletion and amortization	—	—	—
Net capitalized costs	$441,755	$20,745	$462,500
As of December 31, 2009			
Unproved properties(1)	$449,996	$20,745	$470,741
Proved properties	—	—	—
	449,996	20,745	470,741
Accumulated depreciation, depletion and amortization	—	—	—
Net capitalized costs	$449,996	$20,745	$470,741

(1) Capitalized costs are net of sale/like-kind exchange of leasehold interests transactions that occurred in 2010 and 2009 of approximately $0.4 million and $333.3 million for U.S. Gulf of Mexico, $0 and $5.3 million in West Africa, respectively. No gain or loss was recognized for these transactions for the years ended December 31, 2010 and 2009.

20. 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.

	U.S. Gulf of Mexico	West Africa	Total
	($ in thousands)		
Year ended December 31, 2010			
Property acquisition			
Unproved	$ 1,746	$ —	$ 1,746
Proved	—	—	—
Exploration	60,162	29,046	89,208
Development	—	—	—
Total Costs Incurred	$ 61,908	$29,046	$ 90,954
Year ended December 31, 2009			
Property acquisition			
Unproved	$ 14,250	$ —	$ 14,250
Proved	—	—	—
Exploration	23,280	21,872	45,152
Development	—	—	—
Total Costs Incurred	$ 37,530	$21,872	$ 59,402
Year ended December 31, 2008			
Property acquisition			
Unproved	$636,532	$ 1,995	$638,527
Proved	—	—	—
Exploration	23,499	17,775	41,274
Development	—	—	—
Total Costs Incurred	$660,031	$19,770	$679,801

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

The following table reflects the total acreage of the Company's existing oil and gas properties:

	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Acreage at December 31, 2010				
U.S. Gulf of Mexico	—	—	1,317	645
West Africa	—	—	5,653	1,841
Total	—	—	6,970	2,486
Acreage at December 31, 2009				
U.S. Gulf of Mexico	—	—	1,293	639
West Africa	—	—	—	—
Total	—	—	1,293	639

Exhibit Index

Exhibit Number	Description of Document
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))
10.1†	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))
10.2†	Severance Agreement, dated October 23, 2009, among the Company, the Partnership and Samuel H. Gillespie (incorporated by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.3†	Employment Agreement, dated October 23, 2009, among the Company, the Partnership and Rodney L. Gray (incorporated by reference to Exhibit 10.3 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.4†	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))
10.5†	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))
10.6†	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))
10.7	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))
10.8	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))
10.9	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))
10.10	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))
10.11	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))

Exhibit Number	Description of Document
10.12	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))
10.13	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))
10.14†	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))
10.15†	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))
10.16†	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))
10.17†	Long Term Incentive Plan of the Company (incorporated by reference to Exhibit 99.1 to the Company's Registration Statement on Form S-8 filed December 21, 2009 (File No. 333-163883))
10.18†	Deferred Compensation Plan of the Partnership (incorporated by reference to Exhibit 99.2 to the Company's Registration Statement on Form S-8 filed December 21, 2009 (File No. 333-163883))
10.19†	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))
10.20†	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))
10.21†	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))
10.22†	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))
10.23	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))
10.24	Irrevocable Contract Guarantee, dated May 5, 2008, between the Partnership, Ensco Offshore Company and the Guarantors named therein (incorporated by reference to Exhibit 10.20 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.25	Termination and Release of Irrevocable Contract Guarantee, dated December 9, 2009, between Ensco Offshore Company and the Guarantors named therein (incorporated by reference to Exhibit 10.25 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579)).
10.26†*	Form of Non-Qualified Stock Option Award Agreement
10.27†*	Form of Restricted Stock Unit Award Agreement

Exhibit Number	Description of Document
10.28†	Separation Agreement between Rodney L. Gray and the Company, dated June 16, 2010, (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed June 21, 2010 (File No. 001-34579)).
10.29	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)).
10.30	Special Standby Rate and Potential Suspension Agreement dated November 9, 2010 between Cobalt International Energy, L.P. and Ensco Offshore Company (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed November 12, 2010 (File No. 001-34579)).
10.31†	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)).
21.1*	List of Subsidiaries
23.1*	Consent of Ernst & Young LLP
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

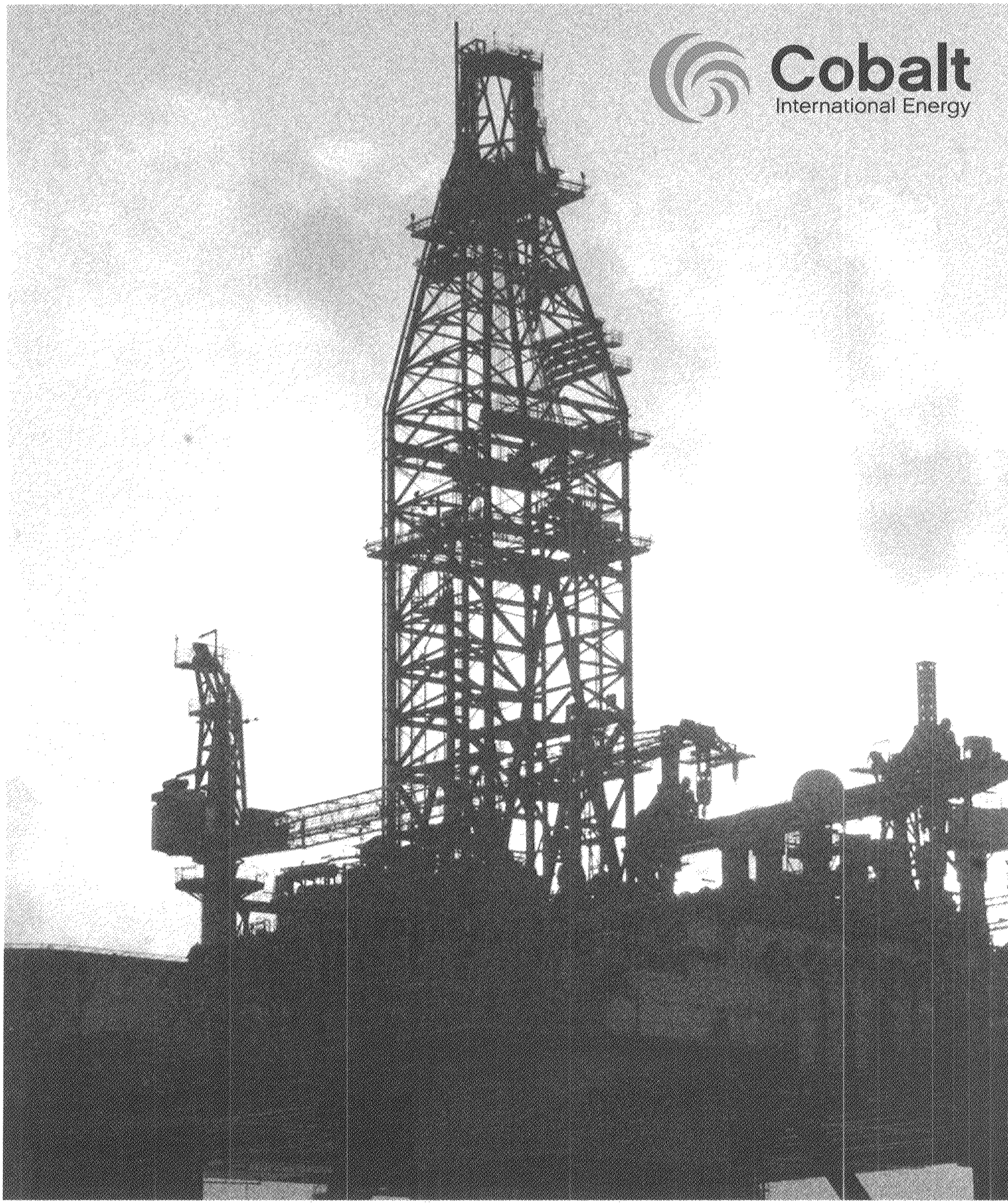
* Filed herewith.

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

(This page has been left blank intentionally.)

(This page has been left blank intentionally.)

(This page has been left blank intentionally.)



Cobalt International Energy, Inc.
Two Post Oak Central
1980 Post Oak Blvd., Suite 1200
Houston, TX 77056
Tel: 713-579-9100 Fax: 713-579-9184
www.cobaltintl.com