VAALCO ENERGY INC /DE/
Form 10-K
March 12, 2012
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2011

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: 1-32167

VAALCO Energy, Inc.

(Exact name of registrant as specified on its charter)

Delaware	**76-0274813**
(State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**Identification No.)**

4600 Post Oak Place

Suite 300

Houston, Texas 77027

(Address of principal executive offices) (Zip Code)

(Registrant s telephone number, including area code): (713) 623-0801

Securities registered under Section 12(b) of the Exchange Act:

Title of each class	Name of exchange on which registered
Common Stock, $.10 par value	New York Stock Exchange

Securities registered under Section 12(g) of the Exchange 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 X

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or such shorter period that the registrant was required to submit and post such files). Yes X 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. X

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

Large accelerated filer __ Accelerated filer X Non-accelerated filer __ Smaller reporting company __

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

The aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates, as of June 30, 2011 was $343,384,364 based on a closing price of $6.02 on June 30, 2011.

As of February 29, 2012, there were outstanding 57,118,925 shares of common stock, $0.10 par value per share, of the registrant.

Documents incorporated by reference: Definitive proxy statement of VAALCO Energy, Inc. relating to the Annual Meeting of Stockholders to be filed within 120 days after the end of the fiscal year covered by this Form 10-K, which is incorporated into Part III of this Form 10-K.

Table of Contents

VAALCO ENERGY, INC.

TABLE OF CONTENTS

Table of Contents

Glossary of Oil and Gas Terms

Terms used to describe quantities of oil and natural gas

Bbl One stock tank barrel, or 42 US gallons liquid volume, of crude oil or other liquid hydrocarbons.

BOE One barrel of oil equivalent, converting gas to oil at the ratio of 6 Mcf of gas to 1 Bbl of oil. The ratio of six Mcf of natural gas to one Bbl of oil or natural gas liquids is commonly used in the oil and gas business and represents the approximate energy equivalency of six Mcf of natural gas to one Bbl of oil or liquids, and does not represent the sales price equivalency of natural gas to oil or liquids. Currently, the sales price of Bbl of oil or natural gas liquids is significantly higher than the sales price of six Mcf of natural gas.

BOPD One barrel of oil per day.

MBbl One thousand Bbls.

Mcf One thousand cubic feet of natural gas.

MMcf One million cubic feet of natural gas.

Terms used to describe the Company s interests in wells and acreage

Gross oil and gas wells or acres The Company s gross wells or gross acres represent the total number of wells or acres in which the Company owns a working interest.

Net oil and gas wells or acres Determined by multiplying gross oil and natural gas wells or acres by the working interest that the Company owns in such wells or acres represented by the underlying properties.

Terms used to assign a present value to the Company s reserves

Standard measure of proved reserves The present value, discounted at 10%, of the pre-United States income tax future net cash flows attributable to estimated net proved reserves. The Company calculates this amount by assuming that it will sell the oil and gas production attributable to the proved reserves estimated in its independent engineer s reserve report for the prices used in the report, unless it had a contract to sell the production for a different price. The Company also assumes that the cost to produce the reserves will remain constant at the costs prevailing on the date of the report. The assumed costs are subtracted from the assumed revenues resulting in a stream of future net cash flows. Estimated future income taxes using rates in effect on the date of the report are deducted from the net cash flow stream. The after-tax cash flows are discounted at 10% to result in the standardized measure of the Company s proved reserves.

Terms used to classify the Company s reserve quantities

Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing

Table of Contents

economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Standardized measure. Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission, using prices and costs in effect as of the date of estimation, without giving effect to non property related expenses such as certain general and administrative expenses, debt service and future federal income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%.

Table of Contents

Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Unproved properties. Properties with no proved reserves.

Terms which describe the productive life of a property or group of properties

Reserve life. A measure of the productive life of an oil and gas property or a group of oil and gas properties, expressed in years. Reserve life for the years ended December 31, 2011, 2010 or 2009 equal the estimated net proved reserves attributable to a property or group of properties divided by production from the property or group of properties for the four fiscal quarters preceding the date as of which the proved reserves were estimated.

Terms used to describe the legal ownership of the Company s oil and gas properties

Royalty interest. A real property interest entitling the owner to receive a specified portion of the gross proceeds of the sale of oil and natural gas production or, if the conveyance creating the interest provides, a specific portion of oil and natural gas produced, without any deduction for the costs to explore for, develop or produce the oil and natural gas. A royalty interest owner has no right to consent to or approve the operation and development of the property, while the owners of the working interests have the exclusive right to exploit the minerals on the land.

Working interest. A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.

Terms used to describe seismic operations

Seismic data. Oil and gas companies use seismic data as their principal source of information to locate oil and gas deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.

Table of Contents

2-D seismic data. 2-D seismic survey data has been the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data.

3-D seismic data. 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated.

Table of Contents

PART I

Item 1. Business

BACKGROUND

VAALCO Energy, Inc., a Delaware corporation incorporated in 1985, is a Houston-based independent energy company principally engaged in the acquisition, exploration, development and production of crude oil and natural gas. VAALCO owns producing properties and conducts exploration activities as an operator in Gabon, West Africa, conducts exploration activities as an operator in Angola, West Africa, conducts exploration activities as an operator and has conducted exploration activities as a non-operator in the British North Sea. VAALCO is the operator of three shale properties in the United States located in Montana and Texas. The Company also owns minor interests in conventional production activities as a non-operator in the United States. As used in this report, the terms Company , we, us , and VAALCO mean VAALCO Energy, Inc. and its subsidiaries, unless the context otherwise requires. The Company s corporate headquarters are located at 4600 Post Oak Place, Suite 300, Houston, Texas 77027 where the telephone number is (713) 623-0801.

VAALCO s international subsidiaries are VAALCO Gabon (Etame), Inc., VAALCO Production (Gabon), Inc., VAALCO Angola (Kwanza), Inc., VAALCO UK (North Sea), Ltd., and VAALCO International, Inc. VAALCO Energy (USA), Inc. holds interests in properties located in the United States.

RECENT DEVELOPMENTS

Offshore Gabon

The Company s primary source of revenue is from the Etame Production Sharing Contract related to the Etame Marin block located offshore the Republic of Gabon. VAALCO operates the Etame Marin block on behalf of a consortium of companies. At December 31, 2011, VAALCO owned a 30.35% interest in the exploration acreage within the Etame Marin block. The Company owns a 28.1% interest in the development areas in and surrounding the Etame, Avouma, South Tchibala and Ebouri fields, each of which is located on the Etame Marin block. The development areas were subject to a 7.5% back-in by the Government of Gabon, which occurred for these fields after their successful development.

The Company produces from the Etame, Avouma, South Tchibala and Ebouri fields on the block. Oil production commenced from the Etame field in September 2002, from the Avouma and South Tchibala fields in January 2007, and from the Ebouri field in January 2009. During 2011, the Etame, Avouma, South Tchibala and Ebouri fields produced approximately 8.1 million bbls (2.3 million bbls net to the Company). The Company s share of barrels sold reflect a reduction for royalty and an allocation of cost oil and profit oil.

The Company has two platforms in the Etame Marin block. During 2011, the Company invested in platform modifications to both of the offshore platforms to accommodate the drilling of additional wells planned to begin in the second half of 2012. Additionally, the Company commenced electrical and power generation upgrades on both platforms. The Company also invested in the construction of water knock-out facilities for the Avouma platform, which it expects to install in mid-2012 along with a new personnel accommodation module.

During 2011, plans to build a third platform to be located in the Etame field were advanced resulting in the contracting for detailed engineering specifications in early 2012. This platform would allow the Company to drill multiple wells in the Etame field. A possible fourth platform continues to be evaluated by the Company and its block partners to develop the 2010 discovery in the Southeast Etame area as part of future development plans for the Etame Marin block.

The sixth exploration period expires in July 2014. Prior to the expiration of this period, the Company is obligated to drill two exploration wells. In 2010, the Company fulfilled one of the two required exploration well obligations with the drilling of the Omangou well, an unsuccessful effort. The remaining commitment in the exploration period is the drilling of one additional exploration well.

Onshore Gabon

The Company executed a farm-out agreement in August 2010 with Total Gabon on the Mutamba Iroru block located onshore near the coast in central Gabon. The Mutamba Iroru block contains an exploration area of approximately 270,000 acres. Under the terms of the agreement, the Company and Total Gabon committed to reprocess 400 kilometers of 2-D seismic data and drill one exploration well. During 2011, the seismic work was substantially completed. Drilling of the exploration well is expected in mid-2012. In return for funding 75% of the work commitment (seismic reprocessing and exploration well costs), Total Gabon will receive a 50% interest on the permit. In 2010, the exploration permit was successfully extended until May 2012 and an application for a further extension is expected to be made in the first quarter of 2012. However, the Company can provide no assurances that such a request will be granted.

Offshore Angola

In November 2006, the Company signed a production sharing contract for Block 5 offshore Angola. The four year primary term with an optional three year extension awards the Company exploration rights to 1.4 million acres offshore central Angola. The Company s working interest is 40%. Additionally, the Company is required to carry the Angolan national oil company, Sonangol P&P, for 10% of the work program. During the first four years of the contract the Company was required to acquire and process 1,000 square kilometers of 3-D seismic data, drill two exploration wells and expend a minimum of $29.5 million ($14.8 million net to the Company). The Company fulfilled its seismic obligation when it acquired 1,175 square kilometers of 3-D seismic data at a cost of $7.5 million ($3.75 million net to the Company) in January 2007 and 524 square kilometers of 3-D seismic data during the fourth quarter of 2008 at a cost of $6.0 million ($3.0 million net to the Company).

The government-assigned working interest partner was delinquent paying their share of the costs several times in 2009 and consequently was placed in a default position. By a governmental decree dated December 1, 2010, the former partner was removed from the production sharing contract, and a one year time extension was granted for drilling the two exploration commitment wells. Following the decree, the Company and the government of Angola have been working together to obtain a replacement partner. Options to amend the two-well commitment are also being discussed with the Angolan government. Because of the uncertainty surrounding the outcome of the discussions with the Angolan government, the Company recorded a full allowance of $4.4 million in 2011, against the accounts receivable from partners for the amounts owed to the Company above its 40% working interest plus the 10% carried interest. In early 2012, the Angolan government granted a further one year extension for drilling the two exploration commitment wells in accordance with the production sharing contract.

Due to the timing uncertainty of obtaining a replacement partner and the outcome of discussions regarding modifying the drilling well commitments required by the production sharing contract, a time extension may be necessary beyond the current expiration date of November 30, 2012. The Company can provide no assurances that such an extension will be granted, if necessary. If the government of Angola were to deny a request for a further time extension, the Company may be required to impair its leasehold costs and other investments totaling $11.0 million as of December 31, 2011. The Company may also have to make a $10.0 million payment for failing to drill the two exploration commitment wells.

Onshore Domestic-Texas

The Company acquired a 640 acre lease in the Granite Wash formation in North Texas in December 2010 and a 480 acre lease in the same formation in July 2011. The first well on the initial acreage began production in August 2011, although mechanical problems with the well exist and the Company recorded an impairment on the well in the fourth quarter of 2011. In November 2011, the Company commenced drilling a second well on the initial Granite Wash formation lease. The well landed in the objective reservoir in February 2012. Subject to successful fracking in March 2012, we expect production to begin soon thereafter.

The acreage on the first Granite Wash formation is held by production. The expiration date of the primary term of the second Granite Wash lease is August 2014.

Onshore Domestic Montana

In May 2011, the Company acquired a 70% working interest in approximately 5,200 acres (3,640 net acres) in Sheridan County, Montana in the Middle Bakken formation. The Company plans to drill two wells on this acreage in 2012.

In September 2011, the Company acquired a 65% working interest in approximately 22,000 gross acres (14,300 net acres) covering the Middle Bakken and deeper formations in the East Poplar unit and the Northwest Poplar field in Roosevelt County, Montana. Pursuant to the terms of the acquisition, the Company is required to drill three wells at its sole cost, one of which must be drilled by June 1, 2012 and the remaining two wells must be drilled by the end of 2012. A vertical exploration well, which meets the time requirement for drilling the first well, was spudded in December 2011 to evaluate the formations. Two additional wells are expected to be drilled on this property in 2012 in accordance with the terms of the lease.

Domestic Outside Operated

The Company has minor interests in Brazos County, Texas producing from the Buda/Georgetown formations. The Company also owns certain minor non-operated interests in the Ship Shoal area of the Gulf of Mexico and in Pickens County, Alabama. No significant activity was undertaken on these properties in 2011.

See Note 13 to the Company s consolidated financial statements for financial information about the Company s segments.

AVAILABLE INFORMATION

The Company files annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission (SEC). You may read and copy any document the Company files at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the SEC s Public Reference Room. The Company s SEC filings are also available to the public at the SEC s website at www.sec.gov.

You may also obtain copies of the Company s annual, quarterly and current reports, proxy statements and certain other information filed with the SEC, as well as amendments thereto, free of charge from the Company s website at www.vaalco.com. No information from the SEC s or the Company s website is incorporated by reference herein. The Company has placed on its website copies of its Audit Committee Charter, Code of Business Conduct and Ethics, and Code of Ethics for the Chief Executive Officer and Chief Financial Officer. Stockholders may request a printed copy of these governance materials by writing to the Corporate Secretary, VAALCO Energy, Inc., 4600 Post Oak Place, Suite 300, Houston, Texas 77027.

STRATEGY

International

The Company s international strategy is to pursue selective opportunities that are characterized by reasonable entry costs, favorable economic terms, high reserve potential relative to capital expenditures and the availability of existing technical data that may be further developed. The Company believes that it has strong management and technical expertise with proven abilities in identifying international opportunities and establishing favorable operating relationships with host governments and local partners familiar with the local practices and infrastructure. The Company owns producing properties and conducts exploration activities as operator of two exploration licenses in Gabon, and one exploration license in Angola.

In addition, the Company s production strategy is to maximize the value of the reserves discovered in Gabon through exploitation of the Etame Marin block (comprised of the Etame, Avouma, South Tchibala and Ebouri fields) totaling approximately 759,000 gross acres.

Domestic

The Company s domestic strategy is to selectively acquire resource based properties, including liquids-rich shale properties. Beginning in December 2010, the Company has acquired two small leases in the Granite Wash formation in Texas and two larger properties located in the Middle Bakken formation in Montana. The Company also has minor interests in outside operated properties located in Brazos County, Texas, in Pickens County, Alabama, and offshore Louisiana in the Ship Shoal area. The Company s strategy for the outside operated properties is to continue to own the interests and receive its revenue share of the production.

CUSTOMERS

Substantially all of the Company s oil and gas is sold at the well head at posted or indexed prices under short-term contracts, as is customary in the industry. In Gabon, the Company sold oil under a contract with Mercuria Trading NV (Mercuria) which ran through calendar year 2011. For the 2012 calendar year, the Company will also sell its oil under a contract with Mercuria. While the loss of Mercuria as a buyer might have a material effect on the Company in the short term, management believes that the Company would be able to obtain other customers for its crude oil.

Domestic operated production in Texas is sold via two contracts, one for oil and one for gas/natural gas liquids. The Company has access to several alternative buyers for oil and gas sales domestically.

EMPLOYEES

As of December 31, 2011, the Company had 94 full-time employees and consultant contractors, 50 of whom were located in Gabon and 8 of whom were located in Angola. The Company is not yet subject to any collective bargaining agreements, although most of the national employees in Gabon are members of the NEOP (National Organization of Petroleum Workers) union. The Company and NEOP began negotiating a collective bargaining agreement in the first quarter of 2011 which has not been completed as of the end of 2011. The Company believes its relations with its employees are satisfactory.

COMPETITION

The oil and gas industry is highly competitive. Competition is particularly intense from other independent operators and from major oil and natural gas companies with respect to acquisitions of desirable oil and gas properties and contracting for drilling equipment**.** There is also competition for the hiring of experienced personnel. In addition, the drilling, producing, processing and marketing of oil and gas is affected by a number of factors beyond the control of the Company, including but not limited to shortages of drilling rigs, pipe and personnel, which may delay drilling, increase prices and have other adverse effects which cannot be accurately predicted.

The Company s competition for acquisitions, exploration, development and production includes the major oil and gas companies in addition to numerous independent oil companies, individual proprietors, investors and others. Many of these competitors possess financial, technical and personnel resources substantially in excess of those available to the Company, giving those competitors an enhanced ability to evaluate and acquire desirable leases properties or prospects. The ability of the Company to generate reserves in the future will depend on its ability to select and acquire suitable producing properties and prospects for future drilling and exploration.

Table of Contents

INSURANCE

In accordance with industry practice, the Company maintains insurance against some, but not all, of the operating risks to which its business is exposed. The Company currently has insurance policies that include coverage for general liability (includes sudden and accidental pollution), physical damage to its oil and gas properties, operational control of offshore wells, aviation, auto liability, marine liability, worker s compensation and employer s liability, among other things. At the depths and in the areas in which the Company operates, and in light of the vertical and horizontal drilling that it undertakes, the Company typically does not encounter high pressures or extreme drilling conditions.

Currently, the Company has Operator s Extra Expense insurance coverage up to $100 million per occurrence, which includes damage to equipment and sudden and accidental environmental liability coverage. The Company s insurance policies contain maximum policy limits and in most cases, deductibles (generally ranging from $100,000 to $1 million) that must be met prior to recovery. These insurance policies are subject to certain customary exclusions and limitations. In addition, the Company carries $75 million of general liability insurance to cover bodily injury, property damage and pollution affecting third parties arising from its operations.

The Company requires all of its third-party contractors to sign master service agreements in which they agree to indemnify the Company for injuries and deaths of the service provider s employees as well as contractors and subcontractors hired by the service provider. Similarly, the Company generally agrees to indemnify each third-party contractor against claims made by the Company s employees and other contractors. Additionally, each party generally is responsible for damage to its own property.

The third-party contractors that perform hydraulic fracturing operations for the Company sign the master service agreements containing the indemnification provisions noted above. The Company does not currently have any insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. However, the Company believes its general liability and excess liability insurance policies would cover third party claims related to hydraulic fracturing operations and associated legal expenses, in accordance with, and subject to, the terms of such policies.

The Company re-evaluates the purchase of insurance, coverage limits and deductibles annually. Future insurance coverage for the oil and gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. No assurance can be given that the Company will be able to maintain insurance in the future at rates that we consider reasonable and it may elect to self-insure or maintain only catastrophic coverage for certain risks in the future.

ENVIRONMENTAL REGULATIONS

General

The Company s activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control in the United States, Gabon and Great Britain and will be subject to the laws and regulations of Angola when exploration drilling begins. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing laws, rules and regulations regulating the release of materials in the environment or otherwise relating to the protection of the environment will not have a material effect upon the Company s capital expenditures, earnings or competitive position with respect to its existing assets and operations. The

Company cannot predict what effect future regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons and the environment resulting from the Company s operations could have on its activities. In part because they are developing countries, it is unclear how quickly and to what extent Gabon or Angola will increase their regulation of environmental issues in the future; any significant increase in the regulation or enforcement of environmental

Table of Contents

issues by Gabon or Angola could have a material effect on the Company. Developing countries, in certain instances, have patterned environmental laws after those in the United States which are discussed below. However, the extent to which any environmental laws are enforced in developing countries varies significantly.

In the United States, environmental laws and regulations may require the acquisition of permits before drilling commences, the installation of pollution control equipment for our operations, special handling or disposal of materials used in our operations, or remedial measures to mitigate pollution from our operations or on the properties on which we operate. These laws and regulations may also restrict the types of substances used in our drilling operations which can be used or released into the environment or limit or prohibit drilling activities on certain lands such as wetlands or sensitive protected areas.

As a general matter, the oil and gas exploration and production industry has been the subject of increasing scrutiny and regulation by environmental authorities. The trend has been the enactment of new or more stringent requirements on the oil and gas industry. These changes result in increased operating costs, and additional changes could results in further increases in our costs for environmental compliance.

Environmental Regulations in the United States

Solid and Hazardous Waste

The Company currently owns or leases, and in the past has owned or leased, properties that have been used for the exploration and production of oil and gas for many years. Although the Company has utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed or released on or under the properties owned or leased by the Company or on or under locations where such wastes have been taken for disposal. In addition, some of these properties are or have been operated by third parties. The Company has no control over such entities treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. State and federal laws applicable to oil and gas wastes and properties have gradually become stricter over time. The Company could, in the future, be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination, including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

The Company generates wastes, including hazardous wastes that are subject to the federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. The Environmental Protection Agency (EPA) and various state agencies have limited the disposal options for certain wastes, including wastes designated as hazardous under RCRA and state analogs (Hazardous Wastes). Furthermore, although oil and gas wastes generally are exempt from regulation as hazardous waste, certain wastes generated by the Company may be subject to RCRA or comparable state statutes. It is possible that certain wastes generated by the Company s oil and gas operations that are currently exempt may in the future be designated as Hazardous Wastes under RCRA or other applicable statutes and, therefore, may be subject to more rigorous and costly disposal requirements.

Superfund

The federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, generally imposes joint and several liability for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances (Hazardous Substances). These classes of persons, or so-called potentially responsible parties (PRPs), include the current and certain past owners and operators of a facility where there has been a release or threat of release of a Hazardous Substance and persons who disposed of or arranged for the

12

disposal of Hazardous Substances found at a facility. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the PRPs the costs of such action.

Although CERCLA generally exempts petroleum from the definition of Hazardous Substance, in the course of its operations, the Company has generated and will generate substances that may fall within CERCLA s definition of Hazardous Substance and may have disposed of these substances at disposal sites owned and operated by others. The Company may also be the owner or operator of sites on which Hazardous Substances have been released. To its knowledge, neither the Company nor its predecessors have been designated as a PRP by the EPA under CERCLA; the Company also does not know of any prior owners or operators of its properties that are named as PRPs related to their ownership or operation of such properties. States such as Texas have comparable statutes which may cover substances (including petroleum) in addition to those covered under CERCLA**.** In the event contamination is discovered at a site on which the Company is or has been an owner or operator or to which the Company sent regulated substances, the Company could be liable for costs of investigation and remediation and natural resources damages.

Clean Water Act

The Clean Water Act (CWA) and analogous state laws impose restrictions and strict controls regarding the discharge (including spills and leaks) of pollutants, including produced waters and other oil and natural gas wastes, into state waters and waters of the United States, a term broadly defined. These controls have become more stringent over the years, and it is probable that additional restrictions will be imposed in the future. Generally, permits must be obtained to discharge pollutants. The CWA provides for civil, criminal and administrative penalties for unauthorized discharges of oil and hazardous substances and of other pollutants. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or other pollutants. The CWA also prohibits the discharge of fill materials to regulated waters, including wetlands, without a permit. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other pollutants, into state waters. In addition, the EPA has promulgated regulations that may require the Company to obtain permits to discharge storm water runoff, including discharges associated with construction activities. In the event of an unauthorized discharge of wastes, the Company may be liable for penalties and cleanup and response costs.

Oil Pollution Act

The Oil Pollution Act of 1990 (OPA), which amends and augments oil spill provisions of the CWA, imposes certain duties and liabilities on certain responsible parties related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable responsible party includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, the Company may be liable for costs and damages.

The OPA also imposes ongoing requirements on a responsible party, including proof of financial responsibility to cover at least some costs in a potential spill. Certain amendments to the OPA that were enacted in 1996 require owners and operators of offshore facilities that have a worst case oil spill potential of more than 1,000 bbls to demonstrate financial responsibility in amounts ranging from $10 million in specified state waters and $35 million in federal outer continental shelf (OCS) waters, with higher amounts, up to $150 million based upon worst case oil-spill discharge volume calculations. In light of recent events, it is possible that these requirements may become more stringent. The Company believes that currently it has established adequate proof of financial responsibility for its offshore facilities.

Table of Contents

Safe Drinking Water Act and Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing activities are typically regulated by state oil and gas commissions but not at the federal level, as the federal Safe Drinking Water Act expressly excludes regulation of these fracturing activities (except where diesel is a component of the fracturing fluid). Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, there have been recent developments at the federal and state levels that could result in regulation of hydraulic fracturing becoming more stringent and costly. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with interim results of the study anticipated to be available by late 2012 and final results anticipated in 2014. In addition, in December 2011, the EPA published an unrelated draft report concluding that hydraulic fracturing caused groundwater pollution in a natural gas field in Wyoming; this study remains subject to review and public comment.

In addition, a committee of the U.S. House of Representatives conducted an investigation of hydraulic fracturing practices. Moreover, legislation was introduced before Congress to provide for federal regulation of hydraulic fracturing by eliminating the current exemption in the Safe Drinking Water Act, and, further, to require disclosure of the chemicals used in the fracturing process. Also, some states have adopted, and other states are considering adopting, regulations that restrict hydraulic fracturing in certain circumstances or that require disclosure of the chemicals in the fracturing fluids. There are reports that the Bureau of Land Management is considering regulations on hydraulic fracturing activities on federal lands. It is not clear what form the regulations will take and what burdens may be imposed by these regulations.

Further, the EPA has announced an initiative under the Toxic Substances Control Act (TSCA) to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals.

If new laws or regulations imposing significant restrictions or conditions on hydraulic fracturing activities are adopted in areas where the Company conducts business, the Company could incur substantial compliance costs and such requirements could adversely delay or restrict its ability to conduct fracturing activities on its assets.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act, or NEPA, which requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. To the extent that our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA, this process has the potential to delay or impose additional conditions upon the development of oil and natural gas projects.

Endangered Species Act

The Endangered Species Act (ESA) was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service must also designate the species critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. If the Company were to have a portion of its leases designated as critical or suitable habitat, it may adversely impact the value of the affected leases.

Climate Change Legislation

More stringent laws and regulations relating to climate change and greenhouse gases (GHGs) may be adopted in the future and could cause us to incur material expenses in complying with them. The EPA has adopted rules under the Clean Air Act (CAA) for the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V permitting programs. The EPA has adopted a multi-tiered approach to this permitting, with the largest sources first subject to permitting. In addition, both houses of the United States Congress have considered legislation to reduce emissions of greenhouse gases without any ultimate resolution and many states have already taken legal measures to reduce GHG emissions, including, in a few locations, the consideration of a cap and trade program. Most of these cap and trade programs work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances. Depending on the regulatory reach of the EPA s rules or new CAA legislation or implementing regulations restricting the emission of GHGs or state programs, the Company could incur significant costs to control its emissions and comply with regulatory requirements. In addition, in October 2009, the EPA adopted a mandatory GHG emissions reporting program which imposes reporting and monitoring requirements on various industries and in November 2010, expanded this GHG reporting rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities. The Company will incur costs to monitor, keep records of, and report emissions of GHGs. We do not believe that our compliance with applicable monitoring, recordkeeping and reporting requirements under the reporting rule as recently amended will have a material adverse effect on our results of operations or financial position.

Because of the lack of any comprehensive legislative program addressing GHGs, there is a great deal of uncertainty as to how federal and state regulation of GHGs will unfold and how it may impact our industry. Moreover, the federal, regional, state and local regulatory initiatives could adversely affect the marketability of the oil and natural gas that the Company produces. The impact of such future programs cannot be predicted, but the Company does not expect its operations to be affected any differently than other similarly situated domestic competitors.

Air Emissions

The Company s operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. At the Federal level, the Clean Air Act is the primary statute governing air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous (or toxic) air pollutants might require installation of additional controls. Administrative enforcement actions for failure to comply with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or require the Company to forego construction, modification or operation of certain air emission sources.

On July 28, 2011, the EPA proposed a rule to subject oil and gas operations to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) programs under the Clean Air Act, and to impose new and amended requirements under both programs. Under the proposal, the EPA would, among other things, amend standards applicable to natural gas processing plants and would expand the NSPS to include all oil and gas operations, imposing requirements on those operations. The EPA is also proposing NSPS standards for completions of hydraulically fracturing gas wells. The proposed standards include the reduced emission completion techniques. The NESHAPS proposal includes maximum achievable control technology (MACT) standards for certain glycol dehydrators and storage vessels, and revises applicability provisions, alternative test protocols and the availability of the startup, shutdown and maintenance exemption. The EPA is under a court order to finalize the rules, with the current

Table of Contents

deadline of April 3, 2012. Should these rules become final and applicable to our operations, they could result in increased operating and compliance costs, increased regulatory burdens and delays in our operations.

Coastal Coordination

There are various federal and state programs that regulate the conservation and development of coastal resources. The federal Coastal Zone Management Act (CZMA) was passed in 1972 to preserve and, where possible, restore the natural resources of the Nation s coastal zone. The CZMA provides for federal grants for state management programs that regulate land use, water use and coastal development.

In Texas, the Legislature enacted the Coastal Coordination Act (CCA), which provides for the coordination among local and state authorities to protect coastal resources through regulating land use, water, and coastal development. The act establishes the Texas Coastal Management Program (CMP). The CMP is limited to the nineteen counties that border the Gulf of Mexico and its tidal bays. The CCA provides for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the Coastal Management Plan. This review may impact agency permitting and review activities and add an additional layer of review to certain activities undertaken by the Company.

OSHA and Other Regulations

The Company is subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require the Company to organize and/or disclose information about hazardous materials used or produced in its operations.

Hydraulic Fracturing

All of the acreage and undeveloped reserves within the Granite Wash formation are subject to hydraulic fracturing. The hydraulic fracturing process is integral to our overall drilling and completion costs in the Granite Wash formation and represents approximately 40% of the total drilling/completion costs per well.

The Company diligently reviews best practices and industry standards, and complies with all regulatory requirements in the protection of these potable water sources. Protective practices include, but are not limited to, setting multiple strings of protection pipe across the potable water sources and cementing these pipes from setting depth to surface, continuously monitoring the hydraulic fracturing process in real time, and disposing of all non-commercially produced fluids in certified disposal wells at depths below the potable water sources.

Based on current drilling techniques, a typical fracturing procedure for a well in the Granite Wash formation uses approximately 5.0 million gallons of fluid, 4.9 million gallons of which is fresh water, and approximately 0.1 million gallons-equivalent of sand. By volume, fresh water makes up nearly 98% of the total fracturing fluid. Less than 1% of the remaining fluid is comprised of chemicals that are found in household or consumer products.

In compliance with the law enacted in Texas in June 2011 and regulations adopted in December 2011, the Company will disclose hydraulic fracturing data to the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission chemical registry. This disclosure is required for each chemical ingredient that is subject to the requirements of OSHA regulations, as well as the total volume of water used in the hydraulic fracturing treatment. A copy of the completed form will be submitted to the Railroad Commission of Texas with the completion report for the well. Additionally, a list of all other chemical ingredients not required by the registry will also be provided to the Railroad Commission for disclosure on a publicly accessible website.

There have not been any incidents, citations or suits related to the Company s hydraulic fracturing activities involving environmental concerns.

Table of Contents

FORWARD-LOOKING STATEMENTS

This Report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, which are intended to be covered by the safe harbors created by those laws. The Company has based these forward-looking statements on its current expectations and projections about future events. These forward-looking statements include information about possible or assumed future results of the Company s operations. All statements, other than statements of historical facts, included in this Report that address activities, events or developments that the Company expects or anticipates may occur in the future, including without limitation, statements regarding the Company s financial position, operating performance and results, reserve quantities and net present values, market prices, business strategy, derivative activities, the amount and nature of capital expenditures, plans and objectives of the Company s management for future operations are forward-looking statements. When the Company uses words such as anticipate, believe, estimate, expect, intend, forecast, outlook, aim, will, could, should, may, likely, plan, probably or similar expression forward-looking statements. Many risks and uncertainties that could affect the Company s future results and could cause results to differ materially from those expressed in the Company s forward-looking statements include, but are not limited to:

the volatility of oil and natural gas prices;

the uncertainty of estimates of oil and natural gas reserves;

the impact of competition;

the availability and cost of seismic, drilling and other equipment;

operating hazards inherent in the exploration for and production of oil and natural gas;

difficulties encountered during the exploration for and production of oil and natural gas;

difficulties encountered in delivering oil to commercial markets;

discovery, acquisition, development and replacement of oil and gas reserves;

timing and amount of future production of oil and gas;

hedging decisions, including whether or not to enter into derivative financial instruments;

our ability to effectively integrate companies and properties that we acquire;

general economic conditions, including any future economic downturn, disruption in financial markets and the availability of credit;

- changes in customer demand and producers supply;
- future capital requirements and the Company s ability to attract capital;
- currency exchange rates;
- actions by the governments and events occurring in the countries in which we operate;
- actions by our venture partners;
- compliance with, or the effect of changes in, governmental regulations regarding the Company s exploration and production, including those related to climate change;
- actions of operators of the Company s oil and gas properties; and
- weather conditions.

The information contained in this Report, including the information set forth under the heading Risk Factors, identifies additional factors that could cause the Company s results or performance to differ materially from those the Company expresses in its forward-looking statements. Although the Company believes that the

Table of Contents

assumptions underlying its forward-looking statements are reasonable, any of these assumptions and therefore also the forward-looking statements based on these assumptions, could themselves prove to be inaccurate. In light of the significant uncertainties inherent in the forward-looking statements which are included in this Report, the Company s inclusion of this information is not a representation by the Company or any other person that the Company s objectives and plans will be achieved. When you consider the Company s forward-looking statements, you should keep in mind these risk factors and the other cautionary statements in this Report.

The Company s forward-looking statements speak only as of the date made and the Company will not update these forward-looking statements unless the securities laws require the Company to do so. The Company s forward-looking statements are expressly qualified in their entirety by this cautionary statement. In light of these risks, uncertainties and assumptions, any forward-looking events discussed in this Report may not occur.

Item 1A. Risk Factors

You should carefully consider the following risk factors in addition to the other information included in this Report. If any of these risks or uncertainties actually occurs, our business, financial condition and results of operations could be materially adversely affected. Additional risks not presently known to us or which we consider immaterial based on information currently available to us may also materially adversely affect us. In this section, the terms VAALCO , we , us and our refer to VAALCO Energy, Inc. and its subsidiaries, unless the context clearly indicates otherwise.

Almost all of the value of our production and reserves is concentrated in a single block offshore Gabon, and any production problems or reductions in reserve estimates related to this property would adversely impact our business.

The Etame field consisting of five producing wells, the Avouma and South Tchibala fields consisting of one well and two wells, respectively, and the Ebouri field with three producing wells constituted almost 98% of our total production for the year ended December 31, 2011. In addition, at December 31, 2011, 94% of our total net proved reserves were attributable to these fields. If mechanical problems, storms or other events curtailed a substantial portion of this production, or if the actual reserves associated with this producing property are less than our estimated reserves, our results of operations and financial condition could be materially adversely affected.

Our results of operations and financial condition could be adversely affected by changes in currency exchange rates.

Our results of operations and financial condition are affected by currency exchange rates. While oil sales are denominated in U.S. dollars, portions of our operating costs in Gabon are denominated in the local currency. A weakening U.S. dollar will have the effect of increasing operating costs while a strengthening U.S. dollar will have the effect of reducing operating costs. The Gabon local currency is tied to the Euro. The exchange rate between the Euro and the U.S. dollar has fluctuated widely in response to international political conditions, general economic conditions, the European sovereign debt crisis and other factors beyond our control.

A decrease in oil and gas prices may adversely affect our results of operations and financial condition.

Our revenues, cash flow, profitability and future rate of growth are substantially dependent upon prevailing prices for oil and gas. Our ability to borrow funds and to obtain additional capital on attractive terms is also substantially dependent on oil and gas prices. Historically, world-wide oil and gas prices and markets have been volatile, and may continue to be volatile in the future. The average price for crude we sold in 2011 was $111.93 per barrel compared to $78.38 per barrel in 2010, and $59.54 per barrel in 2009.

Table of Contents

Prices for oil and gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include international political conditions, including recent uprisings and political unrest in the Middle East and Africa, the European sovereign debt crisis, the domestic and foreign supply of oil and gas, the level of consumer demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, the health of international economic and credit markets, and general economic conditions. In addition, various factors, including the effect of federal, state and foreign regulation of production and transportation, general economic conditions, changes in supply due to drilling by other producers and changes in demand may adversely affect our ability to market our oil and gas production. Any significant decline in the price of oil or gas would adversely affect our revenues, operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of our oil and gas properties and our planned level of capital expenditures.

If there is a sustained economic downturn or recession in the United States or globally, oil and gas prices may fall and may become and remain depressed for a long period of time, which may adversely affect our results of operations.

In recent years, we experienced an economic downturn or a recession in the United States and globally. The reduced economic activity associated with the economic downturn or recession may reduce the demand for, and the prices we receive for, our oil and gas production. A sustained reduction in the prices we receive for our oil and gas production will have a material adverse effect on our results of operations.

Unless we are able to replace reserves which we have produced, our cash flows and production will decrease over time.

Our future success depends upon our ability to find, develop or acquire additional oil and gas reserves that are economically recoverable. Except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, our estimated net proved reserves will generally decline as reserves are produced. There can be no assurance that our planned development and exploration projects and acquisition activities will result in significant additional reserves or that we will have continuing success drilling productive wells at economic finding costs. The drilling of oil and gas wells involves a high degree of risk, especially the risk of dry holes or of wells that are not sufficiently productive to provide an economic return on the capital expended to drill the wells. In addition, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including title problems, weather conditions, political instability, availability of capital, economic/currency imbalances, compliance with governmental requirements, receipt of additional seismic data or the reprocessing of existing data, material changes in oil or gas prices, prolonged periods of historically low oil and gas prices, failure of wells drilled in similar formations or delays in the delivery of equipment and availability of drilling rigs. With the exception of our property acquired in the Granite Wash formation in North Texas in late 2010 and early 2011, and our properties acquired in the Middle Bakken and deeper formations in Montana in 2011, our current domestic oil and gas producing properties are operated by third parties and, as a result, we have limited control over the nature and timing of exploration and development of such properties or the manner in which operations are conducted on such properties.

Substantial capital, which may not be available to us in the future, is required to replace and grow reserves.

We make, and will continue to make, substantial capital expenditures for the acquisition, exploitation, development, exploration and production of oil and gas reserves. Historically, we have financed these expenditures primarily with cash flow from operations, debt, asset sales, and private sales of equity. During 2011, we participated, and in 2012 we expect to continue to participate, in the further exploration and development projects on our international properties. In Gabon and Angola, we are the operator of the blocks and are thus responsible for contracting on behalf of all the remaining parties participating in the project. We rely on the timely payment of cash calls by our partners to pay for the 69.65% share of the Etame budget. Assuming a

19

Table of Contents

replacement partner is obtained and at the same working interest as the former partner, we will rely on the timely payment of cash calls by such partner to pay for the 50% share of the Angola Block 5 budget.

We also expect to continue exploration and development on our Bakken acreage and Granite Wash properties in the U.S. However, if lower oil and gas prices, operating difficulties or declines in reserves result in our revenues being less than expected or limit our ability to borrow funds, or our partners fail to pay their share of project costs, we may have a limited ability, particularly in the current economic environment, to expend the capital necessary to undertake or complete future drilling programs. We cannot assure you that additional debt or equity financing or cash generated by operations will be available to meet these requirements.

Our drilling activities require us to risk significant amounts of capital that may not be recovered.

Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. There can be no assurance that new wells drilled by us will be productive or that we will recover all or any portion of our investment. Drilling for oil and gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. The cost of drilling, completing and operating wells is often uncertain and cost overruns are common. Our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, many of which are beyond our control, including title problems, weather conditions, compliance with governmental requirements and shortages or delays in the delivery of equipment and services.

As part of our exploration and development operations, we have expanded, and expect to further expand, the application of horizontal drilling and multi-stage hydraulic fracture stimulation techniques. The utilization of these techniques requires substantially greater capital expenditures as compared to the drilling of a vertical well. The incremental capital expenditures are the result of additional hydraulic fracture stages in horizontal wellbores.

Weather, unexpected subsurface conditions and other unforeseen operating hazards may adversely impact our oil and gas activities.

The oil and gas business involves a variety of operating risks, including fire, explosions, blow-outs, pipe failure, casing collapse, abnormally pressured formations and environmental hazards such as oil spills, gas leaks, ruptures and discharges of toxic gases, the occurrence of any of which could result in substantial losses to us due to injury and loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. Our production facilities are also subject to hazards inherent in marine operations, such as capsizing, sinking, grounding, collision and damage from severe weather conditions. The relatively deep offshore drilling conducted by us overseas involves increased drilling risks of high pressures and mechanical difficulties, including stuck pipe, collapsed casing and separated cable. The impact that any of these risks may have upon us is increased due to the low number of producing properties we own.

We maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant unfavorable event not fully covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flows. Furthermore, we cannot predict whether insurance will continue to be available at a reasonable cost or at all.

Our reserve information represents estimates that may turn out to be incorrect if the assumptions upon which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present values of our reserves.

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating the underground accumulations of oil and gas that cannot be measured in an exact manner. The estimates included in this document are based on various assumptions required by the SEC, including unescalated prices and costs and capital expenditures subsequent to December 31, 2011, and, therefore, are inherently imprecise indications of future net revenues. Actual future production, revenues, taxes, operating expenses, development expenditures and quantities of recoverable oil and gas reserves may vary substantially from those assumed in the estimates. Any significant variance in these assumptions could materially affect the estimated quantity and value of reserves incorporated by reference in this document. In addition, our reserves may be subject to downward or upward revision based upon production history, results of future development, availability of funds to acquire additional reserves, prevailing oil and gas prices and other factors. Moreover, the calculation of the estimated present value of the future net revenue using a 10% discount rate as required by the SEC is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our reserves or the oil and gas industry in general. It is also possible that reserve engineers may make different estimates of reserves and future net revenues based on the same available data.

The estimated future net revenues attributable to our net proved reserves are prepared in accordance with current SEC guidelines, and are not intended to reflect the fair market value of our reserves. In accordance with the rules of the SEC, our reserve estimates are prepared using an average of beginning of month prices received for oil and gas for the preceding twelve months. Future reductions in prices below the average calculated for 2011 would result in the estimated quantities and present values of our reserves being reduced.

A substantial portion of our proved reserves are or will be subject to service contracts, production sharing contracts and other arrangements. The quantity of oil and gas that we will ultimately receive under these arrangements will differ based on numerous factors, including the price of oil and gas, production rates, production costs, cost recovery provisions and local tax and royalty regimes. Changes in many of these factors do not affect estimates of U.S. reserves in the same way they affect estimates of proved reserves in foreign jurisdictions, or will have a different effect on reserves in foreign countries than in the United States. As a result, proved reserves in foreign jurisdictions may not be comparable to proved reserve estimates in the United States.

We have less control over our foreign investments than domestic investments, and turmoil in foreign countries may affect our foreign investments.

Our international assets and operations are subject to various political, economic and other uncertainties, including, among other things, the risks of war, expropriation, nationalization, renegotiation or nullification of existing contracts, taxation policies, foreign exchange restrictions, changing political conditions, international monetary fluctuations, currency controls and foreign governmental regulations that favor or require the awarding of drilling contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. In addition, if a dispute arises with foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons, especially foreign oil ministries and national oil companies, to the jurisdiction of the United States.

Private ownership of oil and gas reserves under oil and gas leases in the United States differs distinctly from our ownership of foreign oil and gas properties. In the foreign countries in which we do business, the state generally retains ownership of the minerals and consequently retains control of, and in many cases participates in, the exploration and production of hydrocarbon reserves. Accordingly, operations outside the United States may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges.

Almost all of our proven reserves are located offshore of the Republic of Gabon. As of December 31, 2011, we carried a gross investment of approximately $187.2 million including leasehold and asset retirement obligations on our balance sheet associated with the Etame, Avouma, South Tchibala and Ebouri fields in Gabon. We have operated in Gabon since 1995 and believe we have good relations with the current Gabonese government. However, there can be no assurance that present or future administrations or governmental regulations in Gabon will not materially adversely affect our operations or cash flows.

21

Table of Contents

A third time extension for the drilling of two exploration wells in Angola may be necessary to prevent the loss of our investment in that country.

Due to financial non-performance of the venture partner assigned by the government of Angola, our plans to drill the two obligatory wells have been delayed. A government decree effective December 1, 2010 removed the former partner from the production sharing agreement and provided us with a one year extension through the end of November 2011, which has subsequently been extended through the end of November 2012. We continue to work with the government of Angola to secure a replacement partner. After a new partner is obtained, another time extension may be required if reasonable time to drill the two commitment wells does not exist. We can give no assurances that another time extension, if necessary, will be granted. If the government of Angola were to deny a further time extension, the Company may be required to impair its leasehold costs and other investments with a carrying value of $11.0 million as of December 31, 2011. The Company may also have to make a $10.0 million payment for failing to drill the two exploration commitment wells.

Competitive industry conditions may negatively affect our ability to conduct operations.

We operate in the highly competitive areas of oil exploration, development and production. We compete with, and may be outbid by, competitors in our attempts to acquire exploration and production rights in oil and gas properties. These properties include exploration prospects as well as properties with proved reserves. There is also competition for contracting for drilling equipment and the hiring of experienced personnel. Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain and hire the personnel necessary to properly evaluate seismic and other information relating to a property;
- our ability to hire experienced personnel, especially for our accounting, financial reporting, tax and land departments;
- the location of, and our ability to access, platforms, pipelines and other facilities used to produce and transport oil and gas production; and
- the standards we establish for the minimum projected return on an investment of our capital.

Our competitors include major integrated oil companies and substantial independent energy companies, many of which possess greater financial, technological, personnel and other resources than we do. These companies may be able to pay more for oil and natural gas properties, evaluate, bid for and purchase a greater number of properties than our financial or human resources permit, and be better able than we are to continue drilling during periods of low oil and gas prices, to contract for drilling equipment and to secure trained personnel. Our competitors may also use superior technology which we may be unable to afford or which would require costly investment by us in order to compete.

The distressed financial conditions of customers could have an adverse impact on us in the event these customers are unable to pay us for the products or services we provide.

Some of our customers may experience, in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. We cannot provide assurance that one or more of our financially distressed customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations or future cash flows. Furthermore, the bankruptcy of one or more of our customers, or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed by the distressed entity or entities. In addition, such events might force such customers to reduce or curtail their future use of our products and services, which could have a material adverse effect on our results of operations and financial condition.

Table of Contents

We may be unable to integrate successfully the operations of any acquisitions with our operations and we may not realize all the anticipated benefits of the recent acquisitions or any future acquisition.

Failure to successfully assimilate any acquisitions could adversely affect our financial condition and results of operations.

Acquisitions involve numerous risks, including:

- operating a significantly larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new business segment or geographic area;
- the risk that oil and natural gas reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- the loss of significant key employees from the acquired business;
- the diversion of management s attention from other business concerns;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities; and
- coordinating or consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions.

Properties that we buy may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities, which could result in material liabilities and adversely affect our financial condition.

One of our growth strategies is to capitalize on opportunistic acquisitions of oil and gas reserves. Any future acquisition will require an assessment of recoverable reserves, title, future oil and gas prices, operating costs, potential environmental hazards, potential tax and ERISA liabilities, and other liabilities and similar factors. Ordinarily, our review efforts are focused on the higher valued properties and are inherently incomplete because it generally is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and potential problems, such as ground water contamination and other environmental conditions and deficiencies in the mechanical integrity of equipment are not necessarily observable even when an inspection is undertaken. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition.

Additional potential risks related to acquisitions include, among other things:

- incorrect assumptions regarding the future prices of oil and gas or the future operating or development costs of properties acquired;
- incorrect estimates of the oil and gas reserves attributable to a property we acquire;
- an inability to integrate successfully the businesses we acquire;
- the assumption of liabilities;

- limitations on rights to indemnity from the seller;
- the diversion of management s attention from other business concerns; and
- losses of key employees at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly.

Compliance with environmental and other government regulations could be costly and could negatively impact production.

The laws and regulations of the United States, Gabon, Angola and Great Britain regulate our current business. Our operations could result in liability for personal injuries, property damage, natural resource damages, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. Failure to comply with environmental laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties and the issuance of orders enjoining operations. In addition, we could be liable for environmental damages caused by, among others, previous property owners or operators. We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change and greenhouse gases and use of fracking fluids, resulting in increased operating costs. As a result, substantial liabilities to third parties or governmental entities may be incurred, the payment of which could have a material adverse effect on our financial condition, results of operations and liquidity. Additionally, more stringent GHG regulation could impact demand for oil and gas.

These laws and governmental regulations, which cover matters including drilling operations, taxation and environmental protection, may be changed from time to time in response to economic or political conditions and could have a significant impact on our operating costs, as well as the oil and gas industry in general. While we believe that we are currently in compliance with environmental laws and regulations applicable to our operations, no assurances can be given that we will be able to continue to comply with such environmental laws and regulations without incurring substantial costs.

Significant physical effects of climatic change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects.

In an interpretative guidance on climate change disclosures, the SEC indicates that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production activities either because of climate-related damages to our facilities in our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect affect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. In addition, our hydraulic fracturing operations require large amounts of water. Should climate change or other drought conditions occur, our ability to obtain water in sufficient quality and quantity could be impacted and in turn, our ability to perform hydraulic fracturing operations could be restricted or made more costly.

Our sales of oil and natural gas are affected by the availability, terms and cost of pipeline transportation.

The price and terms for access to pipeline transportation remain subject to extensive federal and state regulation. If these regulations change, we could face higher transmission costs for our production and, possibly, reduced access to transmission capacity.

Table of Contents

Various proposals and proceedings that might affect the petroleum industry are pending before Congress, the Federal Energy Regulatory Commission, or FERC, various state legislatures, and the courts. The industry historically has been heavily regulated and we can offer you no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue nor can we predict what effect such proposals or proceedings may have on our operations.

If our assumptions underlying accruals for abandonment costs are too low, we could be required to expend greater amounts than expected.

Almost all of our producing properties are located offshore. The costs to abandon offshore wells may be substantial. For financial accounting purposes, we record the fair value of a liability for an asset retirement obligation in the period in which it is incurred by capitalizing it as part of the carrying amount of the long-lived assets. No assurances can be given that such reserves will be sufficient to cover such costs in the future as they are incurred.

From time to time we may hedge a portion of our production, which may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil and gas.

We may reduce our exposure to the volatility of oil and gas prices by hedging a portion of our production. Hedging also prevents us from receiving the full advantage of increases in oil or gas prices above the maximum fixed amount specified in the hedge agreement. Conversely, hedging may limit our ability to realize cash flows from commodity price increases. In a typical hedge transaction, we have the right to receive from the hedge counterparty the excess of the maximum fixed price specified in the hedge agreement over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the maximum fixed price, we must pay the counterparty this difference multiplied by the quantity hedged even if we had insufficient production to cover the quantities specified in the hedge agreement. Accordingly, if we have less production than we have hedged when the floating price exceeds the fixed price, we must make payments against which there are no offsetting sales of production. If these payments become too large, the remainder of our business may be adversely affected.

In addition, hedging agreements expose us to risk of financial loss if the counterparty to a hedging contract defaults on its contract obligations. This risk of counterparty performance is of particular concern given the disruptions that occurred in the financial markets that lead to sudden changes in a counterparty s liquidity and hence their ability to perform under the hedging contract.

The adoption of derivatives legislation by the U.S. Congress could have an adverse effect on the Company s ability to use derivative instruments to reduce the effect of commodity price, interest rate, and other risks associated with its business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), signed into law in 2010, establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. The new legislation required the Commodities Futures Trading Commission (CFTC) and the Securities and Exchange Commission (SEC) to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In July 2011, the CFTC granted temporary exemptive relief from certain swap regulation provisions of the legislation until December 21, 2011, or until the agency finalized the corresponding rules. In December 2011, the CFTC extended the potential latest expiration date of the exemptive relief to July 16, 2012. In its rulemaking under the new legislation, the CFTC has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain *bona fide* hedging transactions or positions are exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize other regulations, including critical rulemaking on the definition of swap , swap dealer and major swap participant. Depending on our classification, the financial reform legislation may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our

derivative activities. The financial reform legislation may also require the counterparties to derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts and reduce the availability of derivatives to protect against risks we encounter. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural-gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

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

In recent years, the Obama administration s budget proposals and other proposed legislation have included the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production. If enacted into law, these proposals would eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for U.S. production activities and (iv) the increase in the amortization period from two years to seven years for geophysical costs paid or incurred in connection with the exploration for or development of, oil and gas within the United States. It is unclear whether any such changes will be enacted or how soon any such changes would become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could negatively affect the Company s financial condition and results of operations.

We rely on our senior management team and the loss of a single member could adversely affect our operations.

We are highly dependent upon our executive officers and key employees. The unexpected loss of the services of any of these individuals could have a detrimental effect on us. We do not maintain key man life insurance on any of our employees.

We rely on a single purchaser of our Gabon production, which could have a material adverse effect on our results of operations.

Effective January 2011, we sell all of our crude oil production in Gabon to Mercuria and the contract with Mercuria has been extended for calendar year 2012. The loss of Mercuria as a purchaser of our Gabon production could force the shut in of our Gabon production until the purchaser is replaced, and could have a material adverse effect on our results of operations.

Federal legislation and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions but is not subject to regulation at the federal level (except for fracturing activity involving the use of diesel). The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and final results anticipated in 2014. In addition, in December 2011, the EPA published an unrelated draft report concluding that hydraulic fracturing caused groundwater pollution in a natural gas field in Wyoming; this study remains subject to review and public comment. A committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation was introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, New York has imposed a de facto moratorium on the issuance of permits for high-volume, horizontal hydraulic fracturing until state-administered environmental studies are finalized. Further, Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. Any other new laws or regulations that significantly restrict hydraulic fracturing could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect the determination of whether a well is commercially viable. Further, the EPA has announced an initiative under TSCA to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected.

Our management, including our Chief Executive Officer and Chief Financial Officer, do not expect that our internal controls and disclosure controls will prevent all possible error 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. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, an evaluation of controls can only provide reasonable assurance that all material control issues and instances of fraud, if any, in our Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Further, controls can be circumvented by the individual acts of some persons or by collusion of two or more persons. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. A failure of our controls and procedures to detect error or fraud could seriously harm our business and results of operations.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Offshore Gabon- Etame Marin block

VAALCO has an interest in an approximately 759,000 gross acre offshore block in Gabon, the Etame Marin block, where it signed a production sharing contract in 1995. The block contains the Etame, Avouma, South Tchibala and Ebouri fields, all of which are in production, the Southeast Etame area where development plans are being made for this 2010 discovery, and the North Tchibala discovery for which there are no development plans at this time. These fields and discoveries consist of subsalt reservoirs that lie 20 miles offshore in approximately 250 feet of water depth.

VAALCO operates the Etame Marin block on behalf of a consortium of companies. At December 31, 2011, VAALCO owned a 30.35% interest in the exploration acreage within the Etame Marin block. The Company owns a 28.1% interest in the development areas in and surrounding the Etame, Avouma, South Tchibala and Ebouri fields. The development areas were subject to a 7.5% back-in by the Government of Gabon, which occurred for these fields after their successful development.

The Etame Marin block consortium approved the development of the Etame field in 2001. An application for commerciality was filed with the government of Gabon, and in November 2001 the consortium was awarded an approximately 12,000 gross acre exploitation area surrounding the field. The exploitation area has a term of 20 years (through 2021).

The Etame field has been developed at an aggregate cost of approximately $194.9 million ($52.9 million net to the Company). The development included drilling and completing subsea wells connected to a contracted floating production, storage and offloading vessel (FPSO). A successful development well was drilled in 2010 in this field. There are currently five wells producing in the Etame field.

During 2011, plans to build a third platform to be located in the Etame field were advanced resulting in the contracting for detailed engineering specifications in early 2012. This platform would allow the Company to drill multiple wells in the Etame field. A possible fourth platform continues to be evaluated by the Company and its block partners to develop the 2010 discovery in the Southeast Etame area as part of future development plans for the Etame Marin block.

In April 2005, a development plan for the joint development of the Avouma and South Tchibala fields was approved by the Gabon government. The Company was awarded an approximately 13,000 gross acre exploitation area which has a term of 20 years (until 2025). In 2006, the Company installed a platform in approximately 250 feet of water and drilled two development wells from the platform, one into each field. In 2010, a second development well in the South Tchibala field was drilled and successfully completed. The three development wells are tied back to the FPSO via a ten mile pipeline. Through December 31, 2011, the cost of developing the Avouma and South Tchibala fields was approximately $146.1 million ($43.2 million net to the Company).

The Company drilled the Ebouri discovery well to total depth in January 2004. In October 2006, the Gabon government approved the development plan for the Ebouri field and the Company was awarded an approximately 3,700 gross acre exploitation area which has a term of 20 years (until 2026). A platform was installed in July 2008, approximately seven miles from the FPSO and is tied back to the FPSO via a pipeline as was done for the Avouma and South Tchibala fields. The cost of developing the Ebouri field as of December 31, 2011 totaled approximately $188.1 million ($59.0 million net to the Company). The first development well began production in January 2009 and the second development well began producing crude oil in April 2009. A third development well began production in May 2010.

The Company has sold a total of 63.9 million gross bbls (15.2 million net bbls) from the fields within the Etame Marin block since startup in 2002 through December 31, 2011. During 2011, the Etame, Avouma, South Tchibala and Ebouri fields sold approximately 7.8 million gross bbls (1.9 million net bbls).

The Company negotiated an extension of the exploration permit on this block to 2014. The terms of the extension include an additional exploration well, bringing the total required under the permit to two exploration wells, and to acquire additional 3-D seismic data, which was acquired in 2011. One of the two commitment exploration wells has been met with the drilling of the Omangou prospect, an unsuccessful effort, in 2010.

Onshore Gabon Mutamba Iroru block

In November 2005, the Company signed a production sharing contract for the Mutamba Iroru block onshore Gabon. The five year contract awarded the Company exploration rights to approximately 270,000 acres along the central coast of Gabon. The Mutamba Iroru block was previously held by Shell Gabon. The Company acquired aeromagnetic gravity data in 2008, and together with seismic data acquired from previous operators over the block in 2006 and 2007, drilled two exploration wells in 2009. Both wells encountered water bearing sands and were abandoned.

Table of Contents

In 2010, in conjunction with executing a farm-out agreement with Total Gabon, the exploration period was extended until May 2012. This extension requires the Company to reprocess 400 kilometers of 2-D seismic data and drill one exploration well. In return for funding 75% of the work commitment (seismic reprocessing and exploration well costs), Total Gabon will receive a 50% interest on the permit. The seismic reprocessing began in the first quarter of 2011 and was substantially completed by the end of 2011. The exploration well is expected to be drilled in mid-2012. An application for a further exploration period extension is expected to be made in the first quarter of 2012. However, the Company can provide no assurances that such a request will be granted.

Offshore Angola Block 5

In November 2006, the Company signed a production sharing contract for Block 5 offshore Angola. The four year primary term with an optional three year extension awards the Company exploration rights to 1.4 million gross acres offshore central Angola. The Company s working interest is 40%. Additionally, the Company is required to carry the Angolan national oil company, Sonangol P&P, for 10% of the work program. During the first four years of the contract the Company was required to acquire and process 1,000 square kilometers of 3-D seismic data, drill two exploration wells and expend a minimum of $29.5 million ($14.8 million net to the Company). The Company fulfilled its seismic obligation when it acquired 1,175 square kilometers of 3-D seismic data at a cost of $7.5 million ($3.75 million net to the Company) in January 2007 and 524 square kilometers of 3-D seismic data during the fourth quarter of 2008 at a cost of $6.0 million ($3.0 million net to the Company).

The government-assigned working interest partner was delinquent paying their share of the costs several times in 2009 and consequently was placed in a default position. By a governmental decree dated December 1, 2010, the former partner was removed from the production sharing contract, and a one year time extension was granted for drilling the two exploration commitment wells. Following the decree, the Company and the government of Angola have been working together to obtain a replacement partner. Options to amend the two-well commitment are also being discussed with the Angolan government. Because of the uncertainty surrounding the outcome of the discussions with the Angolan government, the Company recorded a full allowance of $4.4 million in 2011 against the accounts receivable from partners for the amounts owed to the Company above its 40% working interest plus the 10% carried interest. In early 2012, the Angolan government granted a further one year extension for drilling the two exploration commitment wells in accordance with the production sharing contract.

Due to the timing uncertainty of obtaining a replacement partner and the outcome of discussions regarding modifying the drilling well commitments required by the production sharing contract, a time extension may be necessary beyond the current expiration date of November 30, 2012. The Company can provide no assurances that such an extension will be granted, if necessary. If the government of Angola were to deny a request for a further time extension, the Company may be required to impair its leasehold costs and other investments totaling $11.0 million as of December 31, 2011. The Company may also have to make a $10.0 million payment for failing to drill the two exploration commitment wells.

Onshore Domestic Texas

The Company acquired a 640 acre lease in the Granite Wash formation in North Texas in December 2010 and a 480 acre lease in the same formation in July 2011. The first well on the initial acreage began production in August 2011, although mechanical problems with the well exist and the Company recorded an impairment on the well in the fourth quarter of 2011. The Company produced 3,656 bbls of oil and 255 MMcf of gas net to the Company from this well in 2011. In November 2011, the Company commenced drilling a second well. The well landed in the objective reservoir in February 2012. Subject to successful fracking in March 2012, we expect production to begin soon thereafter. Total capital expenditures for the well are expected to be $14.0 million, of which $4.0 million was incurred in 2011.

29

Table of Contents

Onshore Domestic Montana

In May 2011, the Company acquired a 70% working interest in approximately 5,200 gross acres (3,640 net acres) in Sheridan County, Montana in the Middle Bakken formation. The Company plans to drill two wells on this acreage in 2012.

In September 2011, the Company acquired a 65% working interest in approximately 22,000 gross acres (14,300 net acres) covering the Middle Bakken and deeper formations in the East Poplar unit and the Northwest Poplar field in Roosevelt County, Montana. A vertical exploration well was spudded in December 2011 to evaluate the formations. An additional two wells are expected to be drilled on this property in 2012.

Domestic Outside Operated

The Company has minor interests in Brazos County, Texas producing from the Buda/Georgetown formations. The Company also owns certain minor non-operated interests in the Ship Shoal area of the Gulf of Mexico and in Pickens County, Alabama. During 2011, these wells produced approximately 330 bbls of oil and 29 million cubic feet of gas net to the Company. No significant activity was undertaken on these properties in 2011 and no capital expenditures are anticipated in 2012 for these properties.

Aggregate Production

Aggregate production data (net to the Company) for all of the Company s operations for the years 2011, 2010, and 2009 are shown below.

Company Owned Production

	Year Ended December 31,								
	2011			2010			2009		
	BOE	**Bbl**	**Mcf**	**BOE**	**Bbl**	**Mcf**	**BOE**	**Bbl**	**Mcf**
Average daily production									
(Oil in BOPD, gas in MCFD)									
Etame, Gabon	2,198	2,198		1,755	1,755		2,079	2,079	
Avouma/S.Tchibala, Gabon	1,368	1,368		1,481	1,481		1,948	1,948	
Ebouri, Gabon	1,542	1,542		1,460	1,460		1,275	1,275	
Hefley, USA(1)	113	10	619						
Other USA properties	14	1	80	9	2	38	5	2	16
Total daily production	5,235	5,119	699	4,705	4,698	38	5,307	5,304	16
Average Sales Price ($/unit)	110.12	111.92	5.23	78.31	78.39	4.79	59.52	59.54	4.79
Production Cost ($/unit)(2)	13.99	13.99	2.33	12.88	12.88	2.15	11.35	11.35	1.89

(1) The Hefley field is the first of the two Granite Wash formation leases acquired by the Company in North Texas

(2) Production cost in $/unit is the ratio of the company s production cost over units of production

Table of Contents

RESERVE INFORMATION

The table below sets forth the Company s estimated net proved reserves for the years ended December 31, 2011, 2010 and 2009 as prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers. There have been no estimates of total proved net oil or gas reserves filed with or included in reports to any federal authority or agency other than the SEC since the beginning of the last fiscal year. The reserves are located in Gabon (offshore) and in Texas and Louisiana (onshore and offshore). Reserves estimated by our independent engineers at December 31, 2011, 2010, and 2009 reflect oil and natural gas spot prices based on the average prices during the 12-month period before the ending date of the period covered by this report determined as an unweighted, arithmetic average of the first-day-of-the-month price for each month within such period.

	As of December 31,		
	2011	2010	2009
Crude Oil			
Proved Developed Reserves (MBbls)			
United States	19	4	4
International	3,835	5,025	4,791
Total Proved Developed Reserves (MBbls)	3,854	5,029	4,795
Proved Undeveloped Reserves (MBbls)			
United States	17		
International	2,177	1,894	2,568
Total Proved Undeveloped Reserves (MBbls)	2,194	1,894	2,568
Total Proved Reserves (MBbls)			
United States	36	4	4
International	6,012	6,918	7,359
Total Proved Reserves (MBbls)	6,048	6,922	7,363
Natural Gas			
Proved Developed Reserves (MMcf)			
United States	856	23	23
International			
Total Proved Developed Reserves (MMcf)	856	23	23
Proved Undeveloped Reserves (MMcf)			
United States	1,069		
International			
Total Proved Undeveloped Reserves (MMcf)	1,069		
Total Proved Reserves (MMcf)			
United States	1,925	23	23
International			
Total Proved Reserves (MMcf)	1,925	23	23
Standardized measure of proved reserves (in thousands)	$ 166,187	$ 124,824	$ 102,518

Proved Undeveloped Reserves

The Company annually reviews all proved undeveloped reserves (PUDs) to ensure an appropriate plan for development exists. Generally, the Company s PUDs are converted to proved developed reserves within five years of the date they are first booked as PUDs. The Company had 2,194 MBbls and 1,069 MMcf of PUDs at December 31, 2011, compared with 1,894 MBbls of PUDs at December 31, 2010. The Company did not convert any PUD s to proved developed reserves in 2011.

Table of Contents

Controls Over Reserve Estimates

The Company s policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the SEC s regulations and GAAP. Compliance in reserves bookings is the responsibility of the Company s Vice President-Production, who is the Company s principal engineer. The Company s principal engineer has over 20 years of experience in the oil and gas industry, including over 10 years as a reserve evaluator, trainer or manager and is a qualified reserves estimator (QRE), as defined by the Society of Petroleum Engineers standards. Further professional qualifications include a degree in petroleum engineering, extensive internal and external reserve training, and asset evaluation and management. In addition, the principal engineer is an active participant in industry reserve seminars, professional industry groups and has been a member of the Society of Petroleum Engineers for over 20 years.

The Company s controls over reserve estimates included retaining Netherland, Sewell & Associates, Inc. (NSAI) as our independent petroleum and geological firm. The Company provided information about the Company s oil and gas properties, including production profiles, prices and costs, to NSAI and they prepare their own estimates of the reserves attributable to our properties. All of the information regarding reserves in this annual report is derived from the report of NSAI. The report of NSAI is included as an exhibit to this Report.

The reserves estimates shown herein have been independently evaluated by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Derek Newton and Mr. Pat Higgs. Mr. Newton has been practicing consulting petroleum engineering at NSAI since 1997. Mr. Newton is a Licensed Professional Engineer in the State of Texas (No. 97689) and has over 26 years of practical experience in petroleum engineering, with over 14 years experience in the estimation and evaluation of reserves. He graduated from University College, Cardiff, Wales, in 1983 with a Bachelor of Science Degree in Mechanical Engineering and from Strathclyde University, Scotland, in 1986 with a Master of Science Degree in Petroleum Engineering. Mr. Higgs has been practicing consulting petroleum geology at NSAI since 1996. Mr. Higgs is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 985) and has over 35 years of practical experience in petroleum geosciences, with over 15 years experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1976 with a Bachelor of Science Degree in Geophysics. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

The Audit Committee of the Board of Directors meets with management, including access to the Company s principal engineer, to discuss matters and policies related to reserves.

Table of Contents

The following tables set forth the net proved reserves of the Company as of December 31, 2011, 2010 and 2009, and the changes during such periods.

	Oil (MBbls)	Gas (MMCF)
PROVED RESERVES:		
BALANCE AT JANUARY 1, 2009	7,422	30
Production	(1,936)	(6)
Revisions of previous estimates	783	(1)
Extensions and discoveries	1,094	
BALANCE AT DECEMBER 31, 2009	7,363	23
Production	(1,715)	(38)
Revisions of previous estimates	1,274	38
Extensions and discoveries		
BALANCE AT DECEMBER 31, 2010	6,922	23
Production	(1,868)	(255)
Revisions of previous estimates	959	31
Extensions and discoveries	35	2,126
BALANCE AT DECEMBER 31, 2011	6,048	1,925

	Oil (MBbls)	Gas (MMCF)
PROVED DEVELOPED RESERVES		
Balance at January 1, 2009	4,751	30
Balance at December 31, 2009	4,795	23
Balance at December 31, 2010	5,029	23
Balance at December 31, 2011	3,854	856

The Company does not book proved reserves on discoveries until such time as a development plan has been prepared and approved by the Company s partners in the discovery. Furthermore, if a government agreement that the reserves are commercial is required to develop the field, this approval must have been received prior to booking any reserves.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of the Company. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and gas sales prices may all differ from those assumed in these estimates. The standardized measure of discounted future net cash flow should not be construed as the current market value of the estimated oil and natural gas reserves attributable to the Company s properties. The information set forth in the foregoing tables includes revisions for certain reserve estimates attributable to proved properties included in the preceding year s estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of a decrease (or increase) in the projected economic life of such properties resulting from changes in product prices. Moreover, crude oil amounts shown for Gabon are recoverable under a service contract and the reserves in place remain the property of the Gabon government.

In accordance with the current guidelines of the SEC, the Company s estimates of future net cash flow from the Company s properties and the present value thereof are made using oil and gas contract prices using a twelve month average price and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. In Gabon,

Table of Contents

the price as of December 31, 2011, was $110.08 per bbl. In the United States, the price as of December 31, 2011, was $78.89 per bbl of oil and $5.439 per Mcf of gas. See Note 16 to the Company s consolidated financial statements for certain additional information concerning the proved reserves of the Company.

Drilling History

In 2011, the Company drilled three wells as follows: two development wells in the Granite Wash formation in North Texas, and one exploratory well in the Middle Bakken and lower formations of the East Poplar unit in Roosevelt County, Montana.

	Domestic						International					
		Gross			Net			Gross			Net	
	2011	2010	2009	2011	2010	2009	2011	2010	2009	2011	2010	2009
Exploratory Wells												
Productive	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.3
Dry	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	4.0	0.0	0.3	2.6
In progress	1.0	0.0	0.0	0.7	0.0	0.0	0.0	1.0	0.0	0.0	0.3	0.0
Development Wells												
Productive	1.0	0.0	0.0	1.0	0.0	0.0	0.0	3.0	2.0	0.0	0.9	0.6
Dry	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
In progress	1.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Wells	3.0	0.0	0.0	2.7	0.0	0.0	0.0	5.0	7.0	0.0	1.5	3.5

Acreage and Productive Wells

Below is the total acreage under lease and the total number of productive oil and gas wells of the
Com (8,119,822) 6,441,716 2,875,698 3,860,830 4,254,785

Common/collective trust
7,817,129
Registered investment companies
30,874 15,741,119
Investment contracts

Limited partnership

Other investments
104,905
Written options
1,057,035
Foreign currency contracts

Short sales
(6,192,653)
Futures
190 4,905,683 12,624,194
Interest

	9,026	142,408	355,623		1,820,846	7,417,797	51,009	71,510	93,354	25,344	88,739	167,443
Dividends	19,480	338,238	3,790,122	1,170,466		988,956	333,156	454,637	138,999	107,501	586,612	
Net investment gain (loss) for the year ended December 2006	$5,367,619	5,192,712	34,298,953	16,911,585	8,351,005	20,539,307	4,308,196	(7,715,156)	6,989,707	3,040,041	4,057,070	5,008,840
Plan participation	%	%	20.3%	36.5%	%	23.9%	18.0%	19.1%	26.6%	27.1%	37.6%	30.4%

(Continued)

GENERAL MILLS 401(k) SAVINGS PLAN

Notes to Financial Statements

December 31, 2007 and 2006

(a) Futures Transactions and Foreign Exchange Contracts

In order to gain exposure to or attempt to protect itself from changes in the market, the Investment Trust may buy and sell stock index futures contracts. Risks of entering into futures contracts, in general, include the possibility there may be an illiquid market and that a change in the value of the contract may not correlate with changes in the value of the underlying securities. Upon entering into a futures contract, the Investment Trust is required to deposit as collateral either cash or securities in an amount (initial margin) equal to a certain percentage of the contract value. Subsequent payments (variation margin) are made or received by the Investment Trust each day. The variation margin payments are equal to the daily changes in the contract value and are recorded as gains and losses.

Certain assets managed by Mellon Transition have a variation margin payable at December 31, 2007 and 2006 totaling $(74,700) and $(483,025), respectively. Investments managed by Mellon Transition, which are held by brokers as collateral on contracts, totaled $648,000 and $6,463,600 at December 31, 2007 and 2006, respectively. The assets are adjusted to fair value and gains and losses are recorded on a daily basis.

Certain assets managed by Numeric Investors have a variation margin receivable (payable) at December 31, 2007 and 2006 totaling $124,661 and $1,925,598, respectively. Investments managed by Numeric Investors that are held by brokers as collateral on contracts totaled $17,351,000 and $13,542,860 at December 31, 2007 and 2006, respectively. The assets are adjusted to fair value and gains and losses are recorded on a daily basis.

Certain assets managed by Western Asset Management Company have a variation margin payable at December 31, 2007 and 2006 totaling $(935,319) and $(548,299), respectively. Investments managed by Western Asset Management Company that are held by brokers as collateral on contracts totaled $9,400,000 and $7,586,000 at December 31, 2007 and 2006, respectively. The assets are adjusted to fair value and gains and losses are recorded on a daily basis.

The Pooled International Developed Markets Fund contains foreign exchange contracts. The net valuation, in U.S. dollars, of the contracts totaled $(258,062) and $507,456 at December 31, 2007 and 2006, respectively. The position of the contracts is valued, and gains and losses are recorded, on a daily basis.

(b) Options Transactions

In order to produce incremental earnings, attempt to protect gains, and facilitate buying and selling of securities for investment purposes, the Investment Trust may buy and sell put and call options, write covered call options on portfolio securities, and write cash-secured puts. The risk in writing a call option is that the fund gives up the opportunity for profit if the market price of the security increases. In writing a put option, the fund may incur a loss if the market price of the security decreases and the option is exercised. In buying an option, the fund pays a premium whether or not the option is exercised. The Investment Trust also has the additional risk of not being able to enter into a closing transaction if a liquid secondary market does not exist. The Investment Trust also may write over-the-counter options where the completion of the obligations is dependent upon the credit standing of the other party.

GENERAL MILLS 401(k) SAVINGS PLAN
Notes to Financial Statements
December 31, 2007 and 2006

Boston Partners Fund had 4,627 option contracts outstanding with market values of $(1,644,121) and $(1,180,260) with a cost of $2,324,305 and $1,088,849 on December 31, 2007 and 2006, respectively.

(c) Investment Contracts with Insurance Companies

The Master Trust contains investment contracts with AIG, Bank of America, and Monumental Life. These insurance companies maintain the contributions in separate pooled accounts. The accounts are credited with earnings on the underlying investments and charged for plan withdrawals and administrative expenses charged by the insurance companies. The contracts are included in the financial statements at contract value (which represents contributions made under the contract, plus earnings, less withdrawals, and administrative expenses), because it is fully benefit responsive. For example, participants may ordinarily direct the withdrawal or transfer of all or a portion of their investment at contract value. There are no reserves against contract value for credit risk of the contract issuer or otherwise. The fair value of the investment contracts at December 31, 2007 and 2006 was $606,954,639 and $556,968,442 respectively. The crediting interest rate is based on an agreed-upon formula with the issuer and is reset quarterly. The crediting interest rate at December 31, 2007 and 2006 was 5.85% and 6.14%, respectively. The average yield at December 31, 2007 and 2006 was 6.43% and 6.01%, respectively.

(6) Company Stock Fund

The Company Stock Fund consists of common stock of General Mills and cash for dividends and fractional shares. At December 31, 2007 and 2006, the market value of the shares held was $102,737,761 and $106,368,818, respectively and the number of shares held was 1,802,417 and 1,846,681, respectively. At December 31, 2007 and 2006, the value of the cash held was $2,004,318 and $274,957, respectively. Participants should refer to the consolidated financial statements of General Mills and subsidiaries included in the Company s Annual Report to Stockholders, which is distributed to all participants in the Plan.

(7) ESOP Fund

The ESOP Fund consists of common stock of General Mills and cash for dividends and fractional shares. All amounts credited to participants ESOP accounts will be invested in the ESOP Fund. Participants may then elect to transfer balances from the ESOP Fund to any of the Plan s other investment funds (note 4). However, no amounts may be transferred from any of the other investment funds into the ESOP Fund.

The ESOP Fund is presented in the following table:

	December 31, 2007		December 31, 2006	
	Allocated	**Unallocated**	**Allocated**	**Unallocated**
General Mills common shares:				
Number of shares	5,195,267	13	5,059,765	107,753
Cost	$148,598,668	750	122,795,399	1,335,898
Market	296,130,227	741	291,442,479	6,206,225

Table of Contents

GENERAL MILLS 401(k) SAVINGS PLAN

Notes to Financial Statements

December 31, 2007 and 2006

In June 1989, the Plan borrowed $92.4 million in a private loan transaction and purchased shares of the Company s common stock. The 8.24% loan provided for quarterly payments through June 30, 2007 and was guaranteed by the Company. The loan was repaid using Company contributions and dividends paid on Company stock owned by the Investment Trust.

(8) Tax Status

The Plan obtained its latest determination letter on March 28, 2003 in which the Internal Revenue Service stated that the Plan, as then designed, was in compliance with the applicable requirements of the Internal Revenue Code (the Code). The Plan has been amended since receiving the determination letter. However, the plan administrator and the Plan s tax counsel believe that the Plan is currently designed and being operated in compliance with the applicable requirements of the Code. Therefore, they believe that the Plan was qualified and the related trust was tax exempt as of the financial statement date.

(9) Parties in Interest

Mellon Trust is a party in interest under the Pension Reform Act with respect to the Plan. Investments held by Mellon Trust are exempt from being considered as prohibited transactions under the Employee Retirement Income Security Act of 1974 (ERISA) Section 408(b).

Hewitt Associates is a party in interest with respect to the Plan and is the Record-keeper of the Plan, and Charles Schwab acts as the Broker for the self-directed brokerage account (Schwab Personal Choice Retirement Account). On April 1, 2006, Hewitt Associates and Charles Schwab replaced Fidelity Investments, which served as both Record-keeper and Broker prior to that date. In the opinion of the Plan s management, transactions between the Plan and the Record-keeper are exempt from being considered as prohibited transactions under ERISA Section 408(b).

The Company is a party in interest with respect to the Plan. The Company is the administrator of the Plan and the ESOP Fund. The Plan invests in common stock of the Company. In addition, the Plan reimburses the Company for services provided, such as wages and travel expenses, associated with the Plan. The cost of services provided for the year ended December 31, 2007 and 2006 was $213,141 and $355,847, respectively. The Company believes these activities are exempt when considering prohibited transactions under ERISA Section 408(b).

Table of Contents

GENERAL MILLS 401(k) SAVINGS PLAN

Notes to Financial Statements

December 31, 2007 and 2006

(10) Reconciliation of Financial Statements to Form 5500

	December 31	
	2007	**2006**
Net assets available for benefits as presented in these financial statements	$ 2,337,329,689	2,198,264,927
Adjustments from contract value to fair value for fully benefit-responsive investment contracts	(9,082,709)	5,115,012
Net assets available for benefits per the Form 5500	$ 2,328,246,980	2,203,379,939

	December 31	
	2007	**2006**
Net increase in net assets available for benefits per the financial statements	139,064,762	215,761,439
Adjustment from contract value to fair value for fully benefit-responsive investment contracts	(14,197,721)	5,115,012
Net increase in net assets available for benefits per the Form 5500	124,867,041	220,876,451

19

Schedule I

GENERAL MILLS 401(k) SAVINGS PLAN
Schedule H, Line 4i Schedule of Assets (Held at End of Year)
December 31, 2007

Issuer	Face amount or number of units	Cost	Current value
Common stock:			
General Mills, Inc.*:			
Participant-directed	6,997,684	$ 227,825,074	398,867,988
Nonparticipant-directed	13	750	741
Unallocated insurance contracts:			
Monumental Life Insurance	15,030,054		15,030,054
Short-term investment fund:			
TBC, Inc. Pooled Employee Funds			
Daily Liquidity Fund*	24,394,954		24,394,954
Participant loan fund*			
(interest rates ranging from 6.25% to 8.0%)	30,860,655		30,860,655
Directed brokerage fund**			66,656,401
Registered investment companies	33,711		5,066,763
Master Trust Investment Accounts (MTIA)	1,788,092,611		1,788,092,611
Total investments			$ 2,328,970,167

* Party in interest.

** Participant-directed investment.

See accompanying report of independent registered public accounting firm.

20

Schedule II

GENERAL MILLS 401(k) SAVINGS PLAN

Schedule H, Line 4j Schedule of Reportable Transactions

Year ended December 31, 2007

5% series of transactions by security issue (iii):

Issuer/description	Purchase price	Selling price	Cost of asset	Current value	Net gain (loss)
Short-term investment fund:					
TBC, Inc. Pooled Employee Funds - Daily Liquidity Fund	$67,006,451		67,006,451	67,006,451	
TBC, Inc. Pooled Employee Funds - Daily Liquidity Fund		65,973,953	65,973,953		

See accompanying report of independent registered public accounting firm.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the General Mills, Inc. Benefit Finance Committee has duly caused this Annual Report to be signed on its behalf by the undersigned hereunto duly authorized.

GENERAL MILLS 401(k) SAVINGS PLAN

By /s/ Daralyn K. Peifer
Daralyn K. Peifer, Executive Secretary of the
General Mills, Inc. Benefit Finance Committee

Date: July 28, 2008

Table of Contents

EXHIBIT INDEX

Exhibit Number	**Description**
23	Consent of KPMG LLP.