ATP
Oil & Gas Corporation

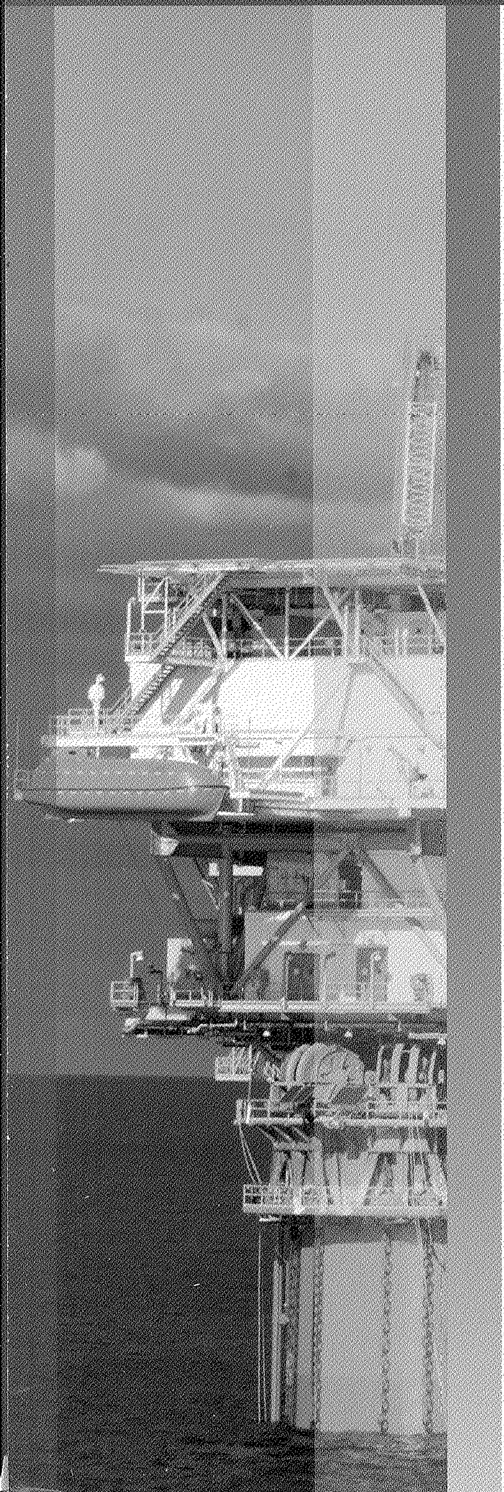
Expertise for Success



Dear Shareholders, Investors and Friends:

ATP is moving forward with tenacity, renewed determination and optimism.

Despite the unprecedented events during the past few years, including the BP oil spill, the moratoriums in the Gulf of Mexico and the resulting enhanced rules and regulations in all areas, ATP has continued to deliver increased production with unmatched attention to safety – everywhere we operate.

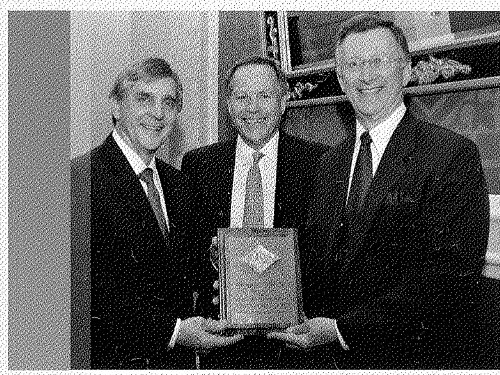


▷ Although ATP sold 80 percent of several significant producing properties in the U.K. in 2008, we increased overall company production in each of the past three years. In 2011, we produced 9.0 million barrels of oil equivalent (MMBoe), 68 percent of which was oil. This represents a 17 percent production increase over 2010. We plan to increase production in 2012 at both Telemark and Clipper, adding a fourth consecutive year of increased production at ATP.

▷ Increased production, coupled with higher oil prices, drove ATP revenues to record highs. Our revenues in 2011 were $687.2 million, up 57 percent over the prior year. For 2012, our projected production increase, buoyed by current and projected oil prices, should deliver another revenue increase.

▷ Oil continues to be the largest component of our reserves, both in the Gulf of Mexico and in the North Sea. Oil comprised 66 percent of our 118.9 MMBoe of proved reserves and 65 percent of our 194.4 MMBoe of proved and probable reserves at year-end 2011. Practically all of our 2012 development activities focus on adding production from these oil properties.

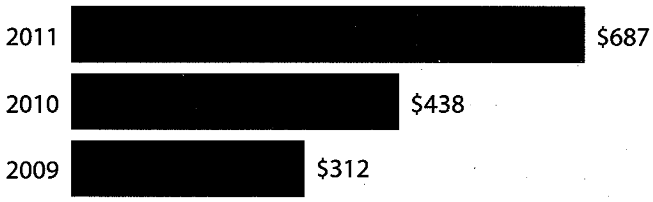
▷ Safety continues as a top priority within ATP. On March 15, 2012, ATP was awarded the Safety-in-Seas Award from the National Ocean Industries Association. ATP was chosen by a blue-ribbon panel of judges from among multiple nominees. The national award recognized ATP for advancing, in an exemplary manner, the safety of offshore energy workers. It also cited the design, conceived three years prior to the Macondo incident, of safety redundancy on the *ATP Titan*, a technologically advanced deepwater drilling and production platform in the Gulf of Mexico.



NOIA Chairman Jack B. Moore presents Safety-in-Seas Award to Gerald W. Schlief and T. Paul Bulmahn of ATP in Washington D.C. ceremony.

Production
(in MBoe)

Revenues
(in millions)



Capacity for Future Success

▷ We will continue to focus on our oil-development projects – Telemark, Clipper, Gomez, and Entrada in the Gulf of Mexico and Cheviot in the North Sea. Since our founding, we have achieved a 98 percent success rate in creating producing properties from nonproducers. We are very proud of this statistic and are dedicated to continuing our success.

▷ Our footprint will expand globally. Our extension into deepwater Israel presents opportunities for ATP – in exploration! Although we expect to operate all of our licensed properties in this new area, our normal working interest will be less than 50 percent. Our working interest in our development projects in the Gulf of Mexico and North Sea, by contrast, is 75 percent to 100 percent. Our reduced interest in Israel will allow us to appropriately manage the exploration risk, both financially and operationally, while using our valuable deepwater technical expertise to pursue one of the most prolific new exploration areas in the world.

▷ We continue to improve our financial position. The moratoriums hit us hard. They caused us to delay and abandon several projects that were meticulously timed to provide a necessary revenue stream. Fortunately, the energy industry is returning to a more normal pace, and we are again addressing our development projects. This enabled us to increase our liquidity in the early part of 2012. We will continue to focus on creating additional liquidity by seeking new partners for certain projects and managing other financial events to give us additional financial strength and flexibility throughout 2012.

Appreciating Human Capital

We could not have navigated these times and delivered these results without our dedicated employees. In 2011, ATP was the fourth most active operator in the deepwater Gulf of Mexico. Only Shell, BP and Anadarko operated more wells in the deep water than ATP. ATP does this with 68 full-time employees.

Clearly, ATP could not achieve this level of activity without surrounding itself with directors, vendors, financial partners and contractors who likewise are dedicated to safe and efficient operations. As founder of the company 21 years ago, I am deeply grateful and thankful for the talent, commitment, enthusiasm and tenacity of each of our employees and all of those who support ATP.

As we advance production and revenues through 2012 and beyond, we are expanding our global presence to increase diversity and generate additional shareholder value.

T. Paul Bulmahn
Founder
Chairman & CEO

Shareholder Information

NASDAQ Global Select Symbol
Common Stock : ATPG

Corporate Headquarters
ATP Oil & Gas Corporation
4600 Post Oak Place, Suite 100
Houston, Texas 77027 USA
Telephone: (713) 622-3311
www.atpog.com

Investor Relations
Telephone: (713) 622-3311
Email: atpinvest@atpog.com

Form 10-K
A copy of the company's 2011 Form 10-K, as filed with the Securities and Exchange Commission, is available on our website www.atpog.com, under Investor Info/Annual Quarterly Reports and SEC Filings, or may be obtained at no charge by written request to Investor Relations at the company's headquarters.

Transfer Agent
American Stock Transfer and Trust Company
59 Maiden Lane
Plaza Level
New York, NY 10038
Toll Free: (800) 937-5449
Telephone: (718) 921-8124
www.amstock.com

Website: www.atpog.com

Exchange: NASDAQ Global Select
Ticker: ATPG

Website and E-mail Alerts
Information concerning the company, including quarterly financial results and news releases, is available on the company's website at www.atpog.com under Investor Info. E-mail alerts about the company's news releases, SEC filings and presentations are available by registering on the company's website.

Officers and Directors

Corporate Officers

T. Paul Bulmahn
Chairman and CEO

Leland E. Tate
President

George R. Morris
Chief Operating Officer

Albert L. Reese, Jr.
Chief Financial Officer; Treasurer

Isabel M. Plume
Chief Communications Officer; Corporate Secretary

Keith R. Godwin
Chief Accounting Officer

John E. Tschirhart
Senior Vice President, International; General Counsel

G. Ross Frazer
Vice President, Engineering

Scott D. Heflin
Vice President, Controller

Timothy P. McGinty
Vice President, Business Development

Mickey W. Shaw
Vice President, Production Operations

Robert M. Shivers, III
Vice President, Projects

Pauline van der Sman-Archer
Vice President, Administration

Directors

T. Paul Bulmahn
Chairman and CEO, ATP Oil & Gas Corporation

Burt A. Adams
President and CEO, OGRS, LLC; Past Chairman, National Ocean Industries Association; Board of Advisors, Tulane University School of Science and Engineering

Chris A. Brisack
United States Immigration Judge; Formerly of Counsel, Rodriguez, Colvin, Chaney & Saenz, LLP, and Partner, Norquest & Brisack, LLP

Arthur H. Dilly
Executive Secretary Emeritus, Board of Regents of the University of Texas System; Chairman Emeritus and Board member, Austin Geriatrics Center

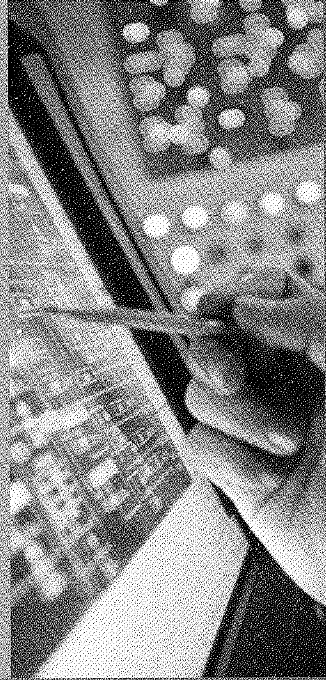
George R. Edwards
Formerly of Counsel, Kissner & Sandvig P.C.

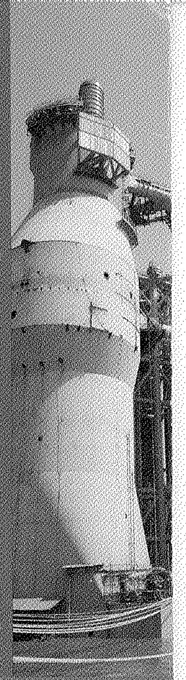
Robert J. Karow
Former President of IPE International and Manager, Oleoducto de Crudos Pesados Ecuador

Brent M. Longnecker
Chairman & CEO, Longnecker & Associates

Gerard J. Swonke
Law Offices of Gerard J. Swonke

Walter Wendlandt
Former Director, Railroad Commission of Texas



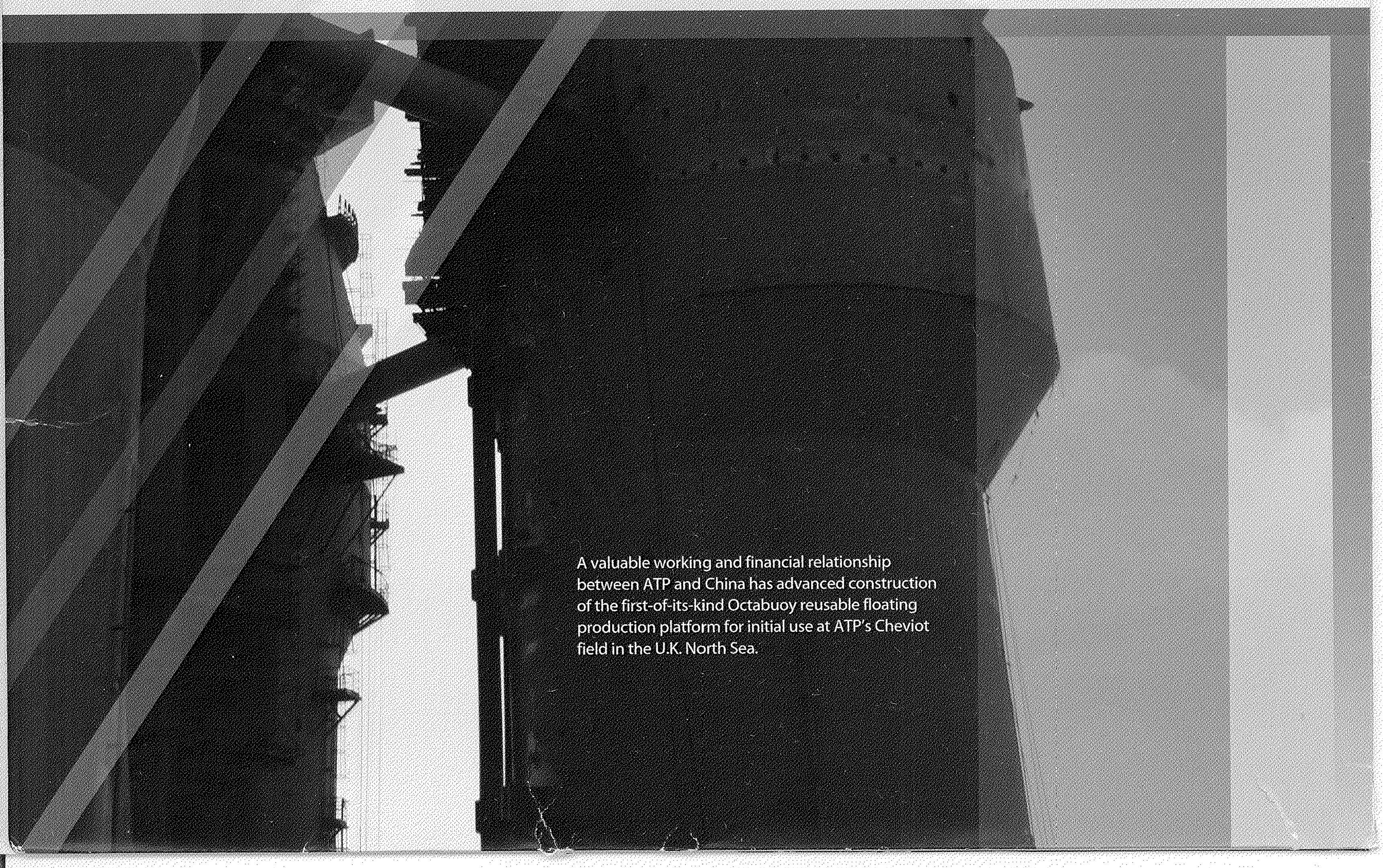


Corporate Profile

ATP Oil & Gas Corporation (NASDAQ: ATPG) is an international offshore oil and gas acquisition, development and production company focused in the Gulf of Mexico, Mediterranean Sea and North Sea. ATP acquires and develops properties, many of which have proved undeveloped reserves at the time of acquisition, that are economically attractive to ATP but not strategic to exploration-oriented oil and gas companies. Such strategy provides ATP with the assets to develop and produce without the risk, cost and time involved in traditional exploration.

Since its inception in 1991, the company has had an exceptionally strong development success record of 98% of converting non-producing properties to commercial production.

Founded in 1991, ATP became a public company in 2001. Headquartered in Houston, Texas, the company's common stock is traded on the NASDAQ Global Select Market under the symbol "ATPG." For more information about ATP, visit **www.atpog.com**.

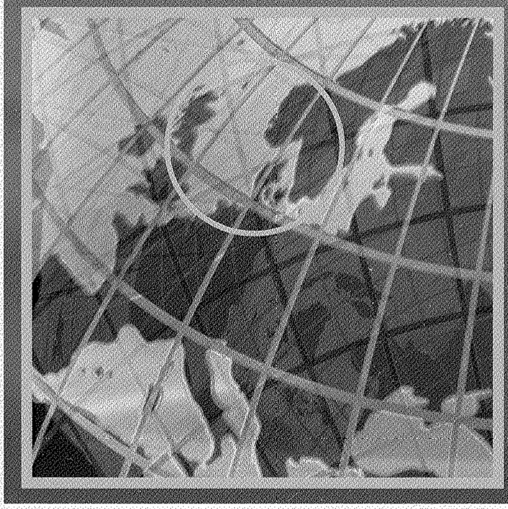


A valuable working and financial relationship between ATP and China has advanced construction of the first-of-its-kind Octabuoy reusable floating production platform for initial use at ATP's Cheviot field in the U.K. North Sea.

ATP OIL & GAS CORPORATION

AREAS OF FOCUS

GULF OF MEXICO



NORTH SEA

MEDITERRANEAN SEA

ATP
OIL & GAS
CORPORATION

ATP Oil & Gas Corporation
4600 Post Oak Place, Suite 100
Houston, Texas 77027 USA
Telephone: (713) 622-3311
Fax: (713) 622-5101
Email: atpinfo@atpog.com

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Fax: +44 (0) 1483 307222

ATP Oil & Gas (Netherlands) B.V.
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Dokweg 31B
1976 CA IJmuiden Netherlands
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Fax: +31 (0) 255 525636

ATP East Med B.V.
15 Abba Eban
Herzliya Pituach
46725 Israel
Telephone: +972 (0) 9 7733081
Fax: +972 (0) 9 7732914

www.atpog.com

ATP OIL & GAS CORPORATION

SEC
Mail Processing
Section

MAY 08 2012

Washington DC
405

April 30, 2012

SEC
Registration Requirements
450 Fifth Street N.W.
Washington, D.C. 20549

To Whom It May Concern:

Enclosed is a copy of the annual report for ATP Oil & Gas Corporation (NASDAQ: ATPG) as required by Rule 14c-3. The Annual report is sent to the SEC solely for its information at the time the Annual Report is sent to Security Holders.

If there are any further questions, please feel free to contact me at 713-403-5517.

Very truly yours,

ATP OIL & GAS CORPORATION

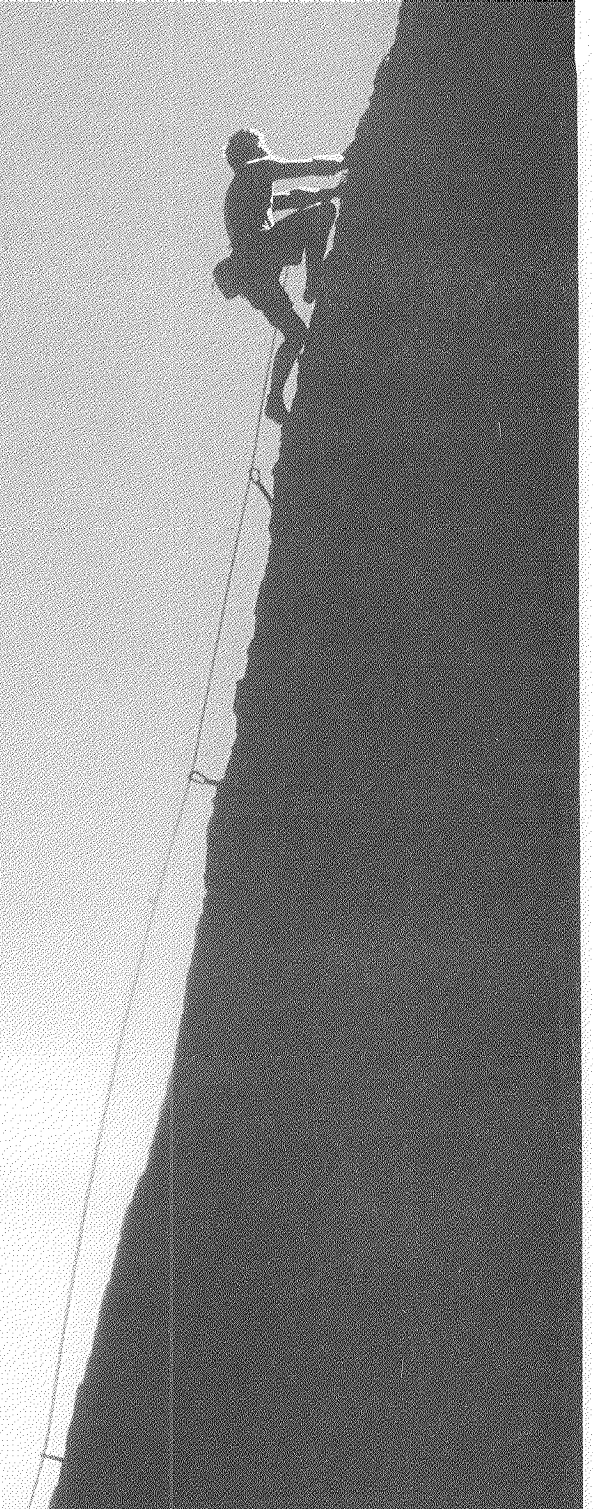
Isabel M. Plume

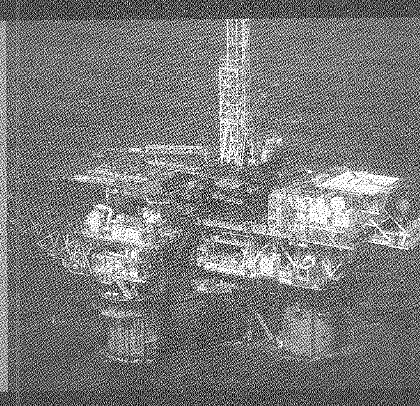
Isabel M. Plume
Chief Communications Officer, Corporate Secretary
ATP Oil & Gas Corporation

ATP
OIL & GAS
CORPORATION

2011 FORM 10-K

EXPERTISE FOR SUCCESS





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

FORM 10-K

☒ **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**

Commission file number: 001-32647

ATP Oil & Gas Corporation

(Exact name of registrant as specified in its charter)

Texas	**76-0362774**
(State of incorporation)	(I.R.S. Employer Identification No.)

4600 Post Oak Place, Suite 100
Houston, Texas 77027
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (713) 622-3311

Securities Registered Pursuant to Section 12 (b) of the Act:

Title of each class	Name of exchange on which registered
Common Stock, par value $.001 per share	NASDAQ Global Select Market

Securities Registered Pursuant to Section 12 (g) of the Act: None

Indicate by check mark if the Registrant is a well-known seasoned issuer as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

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

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

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate website, if any, every interactive Data File required to be submitted electronically and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or such shorter period that Registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by Reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

Large accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ Smaller reporting company ☐

(do not check if a 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☒

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the Registrant as of June 30, 2011 (the last business day of the Registrant's most recently completed second fiscal quarter) was approximately $682.1 million. The number of shares of the Registrant's common stock outstanding as of March 2, 2012 was 52,051,422.

DOCUMENTS INCORPORATED BY REFERENCE

Selected portions of ATP Oil & Gas Corporation's definitive Proxy Statement, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2011, are incorporated by reference in Part III of this Form 10-K.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES
2011 FORM 10-K ANNUAL REPORT
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Cautionary Statement About Forward-Looking Statements

As used in this Annual Report on Form 10-K, the terms "ATP," "we," "us," "our" and similar terms refer to ATP Oil & Gas Corporation and its subsidiaries, unless the context indicates otherwise.

This annual report includes assumptions, expectations, projections, intentions or beliefs about future events. These statements are intended as "forward-looking statements" under the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). Words such as "may," "could," "would," "should," "believes," "expects," "anticipates," "estimates," "projects," "forecasts," "intends," "plans," "targets," "objectives," "seek," "strive," negatives of these words and similar expressions are intended to identify forward-looking statements. Forward-looking statements are based on management's beliefs, assumptions and expectations of our future economic performance, taking into account the information currently available to our management. They are expressions based on historical fact, but do not guarantee future performance. Forward-looking statements involve risks, uncertainties and assumptions and certain other factors that may, and often do, cause our actual results, performance or financial condition to differ materially from the expectations of future results, performance or financial condition we express or imply in any forward-looking statements.

All statements in this document that are not statements of historical fact are forward-looking statements. Forward-looking statements include, but are not limited to:

- projected operating or financial results;
- timing and expectations of financing activities;
- budgeted or projected capital expenditures;
- expectations regarding our planned expansions and the availability of acquisition opportunities;
- statements about the expected drilling of wells and other planned development activities;
- expectations regarding oil and natural gas markets in the U.S., U.K. and Israel; and
- estimates of quantities of our proved reserves and the present value thereof, and timing of future production of oil and natural gas.

We believe these forward-looking statements are reasonable, but we caution that you should not place undue reliance on these forward-looking statements, because there can be no assurance that actual results will not differ materially from those expressed or implied in such forward-looking statements. We do not generally update forward-looking statements, whether written or oral, relating to the matters discussed in this Annual Report on Form 10-K. Some of the key factors which could cause actual results to vary from those expected include:

- the substantial requirements for cash to fund development of our oil and gas properties;
- our inability to generate sufficient funds from our operations and other financing sources;
- the volatility in oil and natural gas prices;
- the timing of planned capital expenditures;
- the timing of and our ability to obtain financing on acceptable terms;
- the inherent uncertainties in estimating proved reserves and forecasting production results;
- our ability to obtain deepwater drilling, pipeline, completion and other permits from the Bureau of Ocean Energy Management;
- uncertainties and operational factors affecting the commencement or maintenance of producing wells, including catastrophic weather-related damage, unscheduled outages or repairs, or unanticipated changes in drilling equipment costs or rig availability;
- delays in the development of or production curtailment at our material properties;
- the condition of the capital markets generally, which will be affected by interest rates, foreign currency fluctuations and general economic conditions;
- costs and other effects of legal and administrative proceedings, settlements, investigations and claims, including environmental liabilities, which may not be covered by indemnity or insurance;
- the political and economic climate in the foreign or domestic jurisdictions in which we conduct oil and gas operations, including risk of war or potential adverse results of military or terrorist actions in those areas;

- other U.S., U.K. or Israel regulatory or legislative developments, which may affect the demand for oil or natural gas, or generally increase the environmental compliance cost for our producing wells or impose liabilities on the owners of such wells;
- interest payment requirements of our debt obligations;
- restrictions imposed by our debt instruments and compliance with our debt covenants;
- our price risk management decisions;
- the unavailability or increased cost of drilling rigs, equipment, supplies, personnel and oilfield services;
- insufficient insurance coverage;
- foreign currency fluctuations;
- rapid production declines in our Gulf of Mexico properties;
- substantial impairment write-downs;
- unidentified liabilities associated with properties that we acquire against which we have not obtained protection from sellers;
- our ability to identify and acquire additional properties necessary to implement our business strategy and our ability to finance such acquisitions;
- competition from our larger competitors in the Gulf of Mexico and the North Sea;
- the loss of members of the management team and other key personnel;
- the ownership by members of our management team of a significant proportion of our common stock;
- rapid growth may place significant demands on our resources; and
- our ability to use net operating losses to offset future taxable income may be limited.

CERTAIN DEFINITIONS

As used herein, the following terms have specific meanings as set forth below:

Bbls	Barrels of crude oil or other liquid hydrocarbons
MBbls	Thousand barrels of crude oil or other liquid hydrocarbons
MMBbls	Million barrels of crude oil or other liquid hydrocarbons
Boe	Barrels of crude oil equivalent
MBoe	Thousand barrels of crude oil equivalent
MMBoe	Million barrels of crude oil equivalent
Mcf	Thousand cubic feet of natural gas
MMcf	Million cubic feet of natural gas
Bcf	Billion cubic feet of natural gas
MMBtu	Million British thermal units
NGL	Natural gas liquids including condensate
SEC	United States Securities and Exchange Commission
U.S.	United States of America
U.K.	United Kingdom of Great Britain and Northern Ireland

Natural gas is converted into barrels of oil equivalent based on six Mcf of gas to one barrel of crude oil or other liquid hydrocarbons.

Development well is a well drilled within the proved area of an oil or natural gas field to the depth of a stratigraphic horizon known to be productive.

Dry hole is a well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploratory well is a well drilled to find and produce oil or natural gas reserves in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

Farm-in or farm-out is an agreement whereby the owner of a working interest in an oil and gas lease or license assigns the working interest or a portion thereof to another party who desires to drill on the leased or licensed acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in," while the interest transferred by the assignor is a "farm-out."

Field is an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

Productive well is a well that is producing or is capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

Proved reserves are the estimated 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 economic conditions, operating methods, and government regulations. Reservoirs are considered proved if shown to be economically producible by either actual production or conclusive formation tests. See Regulation S-X, Rule 4-10(a)(22)-(26), (Reg. § 210.4-10) available on the Internet at www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Proved developed reserves are the portion of proved reserves that can be expected to be recovered 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.

Proved undeveloped reserves are the portion of proved reserves 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.

Working interest is the operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover is operations on a producing well to restore or increase production.

PART I

Item 1. *Business.*

General

ATP Oil & Gas Corporation was incorporated in Texas in 1991 and is engaged internationally in the acquisition, development and production of oil and natural gas properties. Our management team has extensive engineering, geological, geophysical, technical and operational expertise in developing and operating properties in both our current and planned areas of operation. In the Gulf of Mexico and in the U.K. sector of the North Sea (the "North Sea"), we seek to acquire and develop properties with proved undeveloped reserves ("PUD") that are economically attractive to us but are not strategic to major or large independent exploration-oriented oil and gas companies. Occasionally we will acquire properties that are already producing or where previous drilling has encountered reservoirs that appear to contain commercially productive quantities of oil and gas even though the reservoirs do not meet the SEC definition of proved reserves. In the Gulf of Mexico and North Sea, we believe that our strategy provides assets for us to develop and produce with an attractive risk profile at a competitive cost.

During 2011, we acquired three licenses in the Mediterranean Sea covering potential natural gas resources in the deepwater off the coast of Israel ("East Mediterranean"). In the East Mediterranean our licenses relate to exploratory prospects where drilling has occurred nearby and hydrocarbons have been discovered by others. Significant capital investment in the East Mediterranean related to one of these three licenses is expected to begin in 2012.

At December 31, 2011, we had estimated net proved reserves of 118.9 MMBoe, of which approximately 75.9 MMboe (64%) were in the Gulf of Mexico and 42.9 MMBoe (36%) were in the North Sea. The reserves were comprised of 78.6 MMBbls of oil (66%) and 241.5 Bcf of natural gas (34%). Our proved reserves in the deepwater area of the Gulf of Mexico account for 62% of our total proved reserves and our proved reserves on the Gulf of Mexico Outer Continental Shelf account for 2% of our total proved reserves. Our natural gas reserves are split between the Gulf of Mexico (57%) and the North Sea (43%). Of our total proved reserves, 8.3 MMBoe (7%) were producing, 19.0 MMBoe (16%) were developed and not producing and 91.6 MMBoe (77%) were undeveloped. Our average working interest in our properties at December 31, 2011 was approximately 81%. We operate 92% of our platforms. The estimated present value of future net pre-tax cash flows of our proved reserves at December 31, 2011 was $4.2 billion. See "Item 2. Properties – Oil and Natural Gas Reserves" for a reconciliation to our standardized measure of discounted future net cash flows.

At December 31, 2011, in the Gulf of Mexico, we owned leasehold and other interests in 38 offshore blocks and 49 wells, including 23 subsea wells. We operate 43 (88%) of these wells, including 100% of the subsea wells. In the North Sea, we also had interests in 13 blocks and two company-operated subsea wells.

As of the date of this report, we own an interest in 13 platforms including two floating production facilities in the Gulf of Mexico, the *ATP Titan* at our Telemark Hub and the *ATP Innovator* at our Gomez Hub. These floating production facilities are fundamental to our hub strategy and business plan. The presence of these facilities allows us a competitive advantage for additional acquisitions in a large area surrounding each installation. A third floating production facility called an Octabuoy is under construction in China for initial deployment at our Cheviot Hub in the U.K. North Sea which is expected in 2014. We operate the *ATP Innovator* and the *ATP Titan* and we also expect to operate the Octabuoy when it is placed in service. The floating production facilities have longer useful lives than the underlying reserves and are capable of redeployment to new producing locations upon depletion of the reserves. Accordingly, they are expected eventually to be moved several times over their useful lives.

Our Business Strategy

We seek to create value and reduce operating risks through the acquisition and subsequent development of properties in areas that typically have:

- significant undeveloped reserves or nearby discoveries;
- close proximity to developed markets for oil and natural gas;
- existing infrastructure or the ability to install our own infrastructure of oil and natural gas pipelines and production/processing platforms;

- opportunities to aggregate production and create operating efficiencies that capitalize upon our hub concept; and
- a relatively stable regulatory environment for offshore oil and natural gas development and production.

In the Gulf of Mexico and the North Sea, our focus is on acquiring properties that are noncore or nonstrategic to their current owners for a variety of reasons. For example, larger oil companies from time to time adjust their capital spending or shift their focus to exploration prospects they believe offer greater reserve potential. Some projects may provide lower economic returns to a company due to the cost structure and focus of that company. Also, due to timing or budget constraints, a company may be unwilling or unable to develop a property before the expiration of the lease. With our cost structure and acquisition strategy, it is not unusual for us to acquire a property at a cost that is less than the exploration and development costs incurred by the previous owner. This strategy, coupled with our expertise in our areas of focus and our ability to develop projects, tends to make our oil and gas property acquisitions more financially attractive to us than to the seller. Given our strategy of acquiring properties that contain proved reserves, or where previous drilling by others indicates to us the presence of recoverable hydrocarbons, our operations typically are lower risk than exploration-focused Gulf of Mexico and North Sea operators.

Since we operate almost all of the properties in which we acquire a working interest, we are able to influence the plans and timing of a project's development significantly. In addition, practically all of our properties have previously defined and targeted reservoirs, eliminating from our development plan the time necessary in typical exploration efforts to locate and determine the extent of oil and gas reservoirs. We may initiate new development projects by simultaneously obtaining the various required components such as the pipeline and the production platform or subsea well completion equipment.

Our Strengths

- **Low Acquisition Cost Structure**. We believe that our focus on acquiring properties with minimal cash investment for the proved undeveloped component allows us to pursue the acquisition of properties with minimal capital at risk.
- **Significant Infrastructure Investment at our Hubs.** With over $1 billion already invested in infrastructure at our Gomez and Telemark Hubs and more than $492 million related to our Cheviot Hub development, it is our belief that we have a competitive advantage to expand our interest in those areas over other production companies that do not have such an investment.
- **Technical Expertise and Significant Experience**. We have assembled a technical staff with an average of over 29 years of industry experience. Our technical staff has specific expertise in the Gulf of Mexico and North Sea offshore property development, including the implementation of subsea completion technology.
- **Operating Control**. As the operator of a property, we are afforded greater control of the selection of completion and production equipment, the timing and amount of capital expenditures and the operating parameters and costs of the project. As of December 31, 2011, we operated all of our properties under development, all of our subsea wells and 92% of our offshore platforms.
- **Employee Ownership**. Through employee ownership of company stock, we have assembled a staff whose business decisions are aligned with the interests of our shareholders. As of March 1, 2012, our executive officers and directors own approximately 14% of our common stock.
- **Inventory of Projects**. We have substantial reserves to develop in both the Gulf of Mexico and the North Sea.

There are also risk factors that could adversely affect our business. Please see Item 1A. Risk Factors.

Marketing and Delivery Commitments

We sell crude oil and natural gas production under price sensitive or market price contracts. Our revenues, profitability and future growth are substantially dependent on prevailing prices for oil and natural gas. The price received by us for such production can fluctuate widely. Changes in the prices of oil and natural gas will affect the economic viability of some of our proved reserves as well as our revenues, profitability and cash flow. Additionally, involuntary curtailment of our oil or natural gas production, market, economic and regulatory factors may in the future materially affect our ability to sell our oil or natural gas production.

Occasionally, we sell a limited portion of our production utilizing fixed-price forward sales contracts, which require us to deliver a fixed and determinable quantity of oil or gas to a predetermined Gulf of Mexico or North Sea market delivery point. At inception of these contracts we expect to have sufficient production from each local market to satisfy the commitments. Volume information by geographic area at December 31, 2011 regarding our fixed-price forward sales contracts is included in Note 13, "Derivative Instruments and Price Risk Management Activities" to our Consolidated Financial Statements.

Historically, we have sold our oil and natural gas production to a relatively small number of purchasers. Due to the nature of oil and natural gas markets, and because oil and natural gas are commodities and there are numerous purchasers in the areas in which we sell production, we do not believe the loss of a single purchaser, or a few purchasers, would materially affect our ability to sell our production. For the year ended December 31, 2011, revenues from two purchasers accounted for 67% and 20%, respectively, of oil and gas production revenues. No other purchaser individually accounted for more than 10% of oil and gas production revenues.

Competition

We compete with major and independent oil and natural gas companies for property acquisitions. We also compete for the equipment and labor required to operate and to develop these properties. Some of our competitors have substantially greater financial and other resources and may be able to sustain wide fluctuations in the economics of our industry more easily than we can. Since we are in a highly regulated industry, they may be able to absorb the burden of any changes in foreign, federal, state and local laws and regulations more easily than us. Our ability to acquire and develop additional properties in the future will depend upon our ability to conduct operations, to evaluate and select suitable properties, to secure adequate financing and to consummate transactions in this highly competitive environment.

Regulation

Gulf of Mexico

Federal Regulation of Sales and Transportation of Natural Gas. Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated pursuant to the Natural Gas Act of 1938 (the "Natural Gas Act"), the Natural Gas Policy Act of 1978 and Federal Energy Regulatory Commission ("FERC") regulations. In the past, the federal government has regulated the prices at which natural gas could be sold. Deregulation of natural gas sales by producers began with the enactment of the Natural Gas Policy Act of 1978. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining Natural Gas Act and Natural Gas Policy Act of 1978 price and nonprice controls affecting producer sales of natural gas, effective January 1, 1993.

Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. The price and terms for access to pipeline transportation are subject to extensive federal regulation. The FERC requires interstate pipelines to provide open-access transportation on a not-unduly-discriminatory basis for all natural gas shippers. The FERC frequently reviews and modifies its regulations regarding the transportation of natural gas, with the stated goal of fostering competition within all phases of the natural gas industry. We cannot predict what further action the FERC will take with regard to its regulations and open-access policies, nor can we accurately predict whether the FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers.

The Outer Continental Shelf Lands Act, also known as "OCSLA," requires that all pipelines operating on or across the Outer Continental Shelf ("OCS") provide open-access, nondiscriminatory service. Previously, the FERC enforced this provision pursuant to its authority under both the Natural Gas Act and OCSLA. One of FERC's principal goals in carrying out OCSLA's mandate was to increase transparency in the market to provide producers and shippers on the OCS with greater assurance of open access service on pipelines located on the OCS and nondiscriminatory rates and conditions of service on such pipelines. In 2003, the courts determined that the FERC had only limited authority to enforce its open access rules on the OCS and decided, instead, that such authority primarily rested with others, including the U.S. Department of the Interior ("DOI"). The Bureau of Safety and Environmental Enforcement ("BSEE") has jurisdiction under OCSLA to ensure that all shippers seeking service on OCS pipelines transporting oil or gas pursuant to federal easements or rights-of-way on the OCS receive open and nondiscriminatory access to such transportation. In furtherance of this mandate, regulations were issued in 2008 establishing a process for a shipper transporting oil or gas production from OCS leases to follow if it believes it has been denied open and nondiscriminatory access to OCS pipelines and the remedies that BSEE may impose on a transporter that BSEE determines has denied open or nondiscriminatory access to an OCS shipper.

Additional proposals and proceedings that might affect the natural gas industry are pending before FERC and the courts. The natural gas industry historically has been very volatile, and we expect such price volatility to continue. Any extended decline in oil or gas prices could have a material adverse effect on our financial position, results of operations, cash flows, the quantities of oil and gas reserves that we can economically produce, and may restrict the types, quantities and concentration of various substances that can be released into the environment, and impose substantial liabilities for pollution. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctive relief.

Offshore drilling in some areas has been opposed by environmental groups and, in some areas, has been restricted by governmental entities. In addition, following the blowout of the BP Macondo well and the explosion and sinking of the Deepwater Horizon drilling rig in April 2010, the United States government immediately undertook a series of actions in response to the blowout intended, in the near-term and the long-term, to enhance safety and reduce the risk of future environmental disasters related to drilling operations on the OCS. These actions included, among others: (i) the immediate imposition by the DOI of a moratorium, until November 30, 2010, on drilling operations on the OCS in which a subsea blowout preventer ("BOP") or a surface BOP on a floating facility were utilized, which moratorium was officially lifted on October 12, 2010; (ii) a reorganization of the federal Minerals Management Services that resulted in its functions being divided among three new agencies, the Bureau of Ocean Energy Management ("BOEM"), the BSEE, and the Office of Natural Resources Revenue ("ONRR"); and (iii) the promulgation of numerous new rules and regulations affecting the process for obtaining drilling and other permits for oil and gas operations on the OCS, including requirements for enhanced "blowout scenario" and "worst case discharge scenario" plans in connection with Exploration Plans, Development and Production Plans, and Development Operations Coordination Documents filed by OCS producers, compliance with regulations regarding the deployment, use, functionality, and testing of BOPs, well design, well-bore integrity testing, and use of drilling fluids, and enhanced safety requirements to manage operational hazards and impacts involved in offshore drilling. These actions, as well as any laws that are enacted or other governmental actions that are taken in the future to prohibit or restrict offshore drilling or to impose more stringent or costly environmental protection requirements, could have a material adverse effect on the oil and natural gas industry in general and our offshore operations in particular.

Environmental Regulations. The Oil Pollution Act of 1990, also known as "OPA," and related regulations impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in navigable waters, adjoining shorelines or in the exclusive economic zone of the U.S.. A "responsible party" includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for the costs of cleaning up an oil spill and for a variety of public and private damages resulting from a spill. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by a party's gross negligence or willful misconduct, a violation of a federal safety, construction or operating regulation, or a failure to report a spill or to cooperate fully in a cleanup. Even if applicable, the liability limits for offshore facilities require the responsible party to pay all removal costs, plus up to $75.0 million in other damages. Few defenses exist to the liability imposed by the OPA.

The OPA also requires a responsible party to submit proof of its financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. Under this Act, parties responsible for offshore facilities must provide financial assurance of at least $35.0 million ($10.0 million if the offshore facility is located landward of the seaward boundary of a state) to address oil spills and associated damages, with this financial assurance amount increasing up to $150.0 million in certain circumstances depending on the risk represented by the quantity or quality of oil that is handled by the facility. We carry insurance coverage to meet these obligations. The OPA also imposes other requirements, such as the preparation of an oil spill contingency plan. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. We are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's existing financial responsibility and other operating requirements do not have a material adverse affect on us; however, an increase in the amounts of required coverage could have a material adverse affect on us.

We are also regulated by the Clean Water Act, which prohibits any discharge of pollutants into waters of the U.S. except in conformance with discharge permits issued by federal or state agencies. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for stormwater discharges. Costs may be associated with the treatment of wastewater or developing and implementing stormwater pollution prevention plans. We are also subject to similar state and local water quality laws and regulations for any production or drilling activities that occur in state coastal waters. Failure to comply with the ongoing requirements of the Clean Water Act or analogous state laws may subject a responsible party to administrative, civil or criminal enforcement actions and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damage resulting from the release. We are in material compliance with these requirements.

We have in place for our Gulf of Mexico ("GOM") operations a Regional Oil Spill Response Plan ("Response Plan") that covers the uncontrolled release of any hazardous material. The Response Plan details procedures for the rapid and effective response to and remediation of spill events that may occur as a result of ATP's operations. The Response Plan is supplemented and updated as needed.

Our spill management team consists of an integrated organization of key personnel from ATP and a third-party spill management group, O'Brien's Oil Pollution Service, Inc. This team utilizes the National Incident Management System ("NIMS"), which is a nationwide template, or organizational structure, which enables federal, state, and local governments, as well as non-governmental organizations, to work together to prepare for, prevent, if necessary respond to, and mitigate the effects of an incident.

Within the NIMS template is the Incident Command System ("ICS"), which establishes the functional organizational structure of the team ("Response Team"). The ICS represents a best-practices emergency response management structure for meeting the demands of any emergency situation. All members of the Response Team, at a minimum, receive training and are tested through annual spill drills. The Response Team is headed by an Incident Commander who has overall responsibility during the incident mitigation.

We are a member of Clean Gulf Associates ("CGA"), which is a not-for-profit association of producing and pipeline companies operating in the GOM. CGA, coupled with the Marine Spill Response Corporation, manage the response personnel and equipment, which are on call 24 hours a day, seven days a week. All of these personnel and the associated equipment are managed by the Incident Commander through the ICS.

In addition, OCSLA authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the OCS. Specific design and operational standards may apply to OCS vessels, rigs, platforms and structures. Violations of lease conditions or regulations issued pursuant to OCSLA can result in substantial civil and criminal penalties, as well as potential court injunctions curtailing operations and the cancellation of leases. Such enforcement liabilities can result from either governmental or private prosecution.

The Comprehensive Environmental Response, Compensation, and Liability Act, or "CERCLA," also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, responsible persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. While petroleum and natural gas liquids are specifically excepted from the definition of "hazardous substance," other wastes generated during oil and gas exploration and production activities may give rise to cleanup liability under CERCLA. We do not believe that we are associated with any Superfund site and we have not been notified of any claim, liability or damages under CERCLA.

The Safe Drinking Water Act ("SDWA") regulates the underground injection of fluid (such as the reinjection of brine produced and separated from oil and natural gas production) through a well. The SDWA of 1974, as amended establishes a regulatory framework for underground injection, with the main goal being the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Failure to abide by our permits could subject us to civil or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

We may also incur liability under the Resource Conservation and Recovery Act ("RCRA"), which imposes requirements relating to the management and disposal of solid and hazardous wastes. While there exists an exclusion from the definition of hazardous wastes for "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy," in the course of our operations we may generate ordinary industrial wastes, including paint wastes, waste solvents, and waste compressor oils that may be regulated as hazardous substances or hazardous waste. Consequently, we may incur liability for such hazardous substances and hazardous wastes under CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remediate previously disposed wastes or to perform remedial operations to prevent future contamination.

Our operations are also subject to regulation of air emissions under the Clean Air Act ("CAA") and OCSLA. Implementation of these laws could lead to the imposition of new air pollution control requirements on our operations. Therefore, we may incur capital expenditures over the next several years to upgrade our air pollution control equipment. We could also become subject to similar state and local air quality laws and regulations in the future if we conduct production or drilling activities in state coastal waters. However, we do not believe that our operations would be materially affected by any such requirements, nor do we expect such requirements to be any more burdensome to us than to other companies our size involved in similar oil and natural gas development and production activities.

On December 15, 2009, the EPA officially published its "Endangerment Finding," an official finding that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. Under the Endangerment Finding and subsequent regulations, the EPA has begun to promulgate GHG regulations. Beginning on January 2, 2011, certain new "major sources" of greenhouse gases or major sources undergoing major modifications, as defined and categorized by the EPA's "Tailoring Rule" issued on June 3, 2010, are required to obtain air quality permits under the Clean Air Act's Prevention of Significant Deterioration Program. GHG reporting has also become mandatory for specified large GHG emissions sources beginning in 2011 for emissions occurring in 2010, with EPA issuing a final rule on November 30, 2010, requiring reporting of GHG emissions from the oil and gas industry. It is not possible to predict future regulations that may impose reporting obligations or limit GHG emissions within the oil and gas industry. To the extent that those regulations are finalized, we could incur costs to reduce emissions of GHGs associated with our operations. Any such regulations could adversely affect demand for the oil, gas and NGL that the Company produces. Moreover, lawsuits have been filed against other companies seeking to require them to reduce GHG emissions from their operations. These and other lawsuits relating to GHG emissions may result in decisions by state and federal courts and agencies that could impact our operations.

Climate change legislative measures have been under consideration by the U.S. Congress, but it is not possible at this time to predict whether or when the U.S. Congress may act on climate change legislation. Certain states have begun implementing legal measures to reduce emissions of GHGs. Other nations have also been seeking to reduce emissions of GHGs, including participation in the "Kyoto Protocol," an international treaty pursuant to which participating countries (not including the U.S.) have agreed to reduce their emissions of GHGs to below 1990 levels by 2012. Depending on the particular jurisdiction in which the Company's operations are located, laws regulating GHGs may result in capital, compliance, operating, and maintenance costs, but the level of expenditures required to comply with these laws is uncertain and will vary by the Company's activities within these jurisdictions and market conditions.

See also the discussion of drilling permits in Item 7. Risks and Uncertainties.

North Sea

Our proved reserves in the North Sea are located in the U.K. sector. Related government regulations in the U.K. are discussed below.

Regulation of Oil and Natural Gas Production. Pursuant to the Petroleum Act 1998, all oil and natural gas reserves contained in properties located in the U.K. are the property of the U.K. government. The development and production of oil and natural gas reserves in the U.K. Sector - North Sea requires a petroleum production license granted by the U.K. government. Prior to developing a field, we are required to obtain from the Secretary of State for Energy and Climate Change (the "Secretary of State") a consent to commence field development. We would be required to obtain the consent of the Secretary of State prior to transferring an interest in a license. The Petroleum Act 1998 also regulates the abandonment of facilities by licensees.

The terms of U.K. petroleum production licenses are based on model license clauses applicable at the time of issuance of the license. Licenses frequently contain regulatory provisions governing matters such as working method, pollution and training, and reserve to the Secretary of State the power to direct some of the licensee's activities. For example, a licensee is precluded from carrying out development or production activities other than with the consent of the Secretary of State or in accordance with a development plan which the Secretary of State has approved. Breach of these requirements may result in the revocation of the license. In addition, licenses may require payment of fees and royalties on production and also impose certain other duties.

The Petroleum Act 1998 imposes health and safety regulations on our offshore oil and natural gas production activities in the U.K. In addition, the Mineral Workings (Offshore Installations) Act 1971 provides a framework in which the government can impose additional regulations relating to health and safety. Since its enactment, a number of regulations have been promulgated relating to offshore construction and operation of offshore production facilities. Health and safety offshore is further governed by the Health and Safety at Work Act 1974 and applicable regulations.

Environmental Regulations. Our operations are subject to environmental laws and regulations imposed by both the European Union and the U.K. government. The offshore industry in the U.K. is regulated with regard to the environment before and during the conduct of exploration and production activities. The licensing requirements employ a preventive and precautionary approach. This is evident in the consultation that takes place before a U.K. licensing round begins, whereby the Secretary of State, acting through the Department of Energy and Climate Change, will consult with various public bodies having responsibility for the environment. Applicants for production licenses are required to submit a statement of the general environmental policy of the operator in respect of the contemplated license activities and a summary of its management systems for implementation of that policy and how those systems will be applied to the proposed work program. In addition, the Offshore Petroleum Production and Pipe-lines (Assessment of Environmental Effects) Regulations 1999, require the Secretary of State to exercise his licensing powers under the Petroleum Act 1998 in such a way to ensure that an environmental assessment is undertaken and considered before consent is given to certain projects.

Petroleum production licenses require the prior approval of the Secretary of State of a licensee to act as operator. The operator under a license organizes or supervises all or any of the development and production operations of oil and natural gas properties subject thereto. As an operator, we may obtain operational services from third parties, but will remain fully responsible for the operations as if we conducted them ourselves.

Pipelines and Transportation. Our operations in the U.K. may entail the construction of offshore pipelines, which are subject to the provisions of the Petroleum Act 1998 and other legislation. The Petroleum Act 1998 requires a license to construct and operate a pipeline in U.K. North Sea, including its continental shelf. Easements to permit the laying of pipelines must be obtained from the Crown Estate Commissioners prior to their construction. We plan to use capacity in existing offshore pipelines in order to transport our gas. However, access to the pipelines of a third party would need to be obtained on a negotiated basis, and there is no assurance that we can obtain such access to existing pipelines, or obtain access on terms that are favorable to us.

The natural gas we produce may be transported through the U.K.'s onshore national gas transmission system, or NTS. The NTS is owned by a licensed gas transporter, National Grid plc ("National Grid"). The terms on which National Grid must transport gas are governed by the Gas Acts of 1986 and 1995, the gas transporter's license issued to National Grid under those Acts and a network code. For us to use the NTS, we must obtain a shipper's license under the Gas Acts and arrange to have gas transported by National Grid within the NTS. We would therefore be subject to the network code, which imposes obligations for payment, gas flow nominations, capacity booking and correction of system imbalances. Applying for and complying with a shipper's license, and acting as a gas shipper, is expensive and administratively burdensome. Thus, we intend to sell natural gas "at the beach" before it enters the NTS or arrange with an existing gas shipper to ship the gas through the NTS on our behalf.

Compliance. We believe that our operations in the Gulf of Mexico and North Sea are in substantial compliance with current applicable laws and regulations. While we expect that continued compliance with existing requirements will not have a material adverse impact on us, there is no assurance that this will continue.

Employees

At December 31, 2011 we had 59 full-time employees in our Houston office, seven full-time employees in our U.K. office and two full-time employees in our Netherlands office. None of our employees is covered by a collective bargaining agreement. We regularly use the services of independent consultants and contractors to perform various professional services, particularly in the areas of construction, design, well-site supervision, permitting and environmental assessment. Independent contractors usually perform field and on-site production operation services for us, including gauging, maintenance, dispatching, inspection and well testing.

Available Information

Our Internet website is www.atpog.com and you may access, free of charge, through the Investor Relations section of our website, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to such reports filed or furnished pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Information contained on our website is not part of this report. Also, the SEC maintains an internet site (www.sec.gov) that contains reports, proxy and other information about the Company. The Company will provide a copy of the Form 10-K annual report upon the written request of any shareholder. Financial information regarding our operating segments is set forth in Note 14, "Segment Information" of the Notes to Consolidated Financial Statements.

Item 1A. *Risk Factors.*

You should carefully consider the following risks in addition to the other information included in this report. Each of these risks could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock or other securities.

If we are not able to generate sufficient funds from our operations and other financing sources, we may not be able to finance our planned development activity, acquisitions or service our debt.

We have been dependent on debt and equity financing to fund our cash needs that are not funded from operations or the sale of assets. In addition, low commodity prices, production problems, disappointing drilling results and other factors beyond our control could reduce our funds from operations and may restrict our ability to obtain additional financing or to pay interest and principal on our debt obligations. Furthermore, we have incurred losses in the past that may affect our ability to obtain financing. Quantifying or predicting the likelihood of any or all of these occurring is difficult in the current domestic and world economy. For these reasons, financing may not be available to us in the future on acceptable terms or at all. In the event additional capital is required but not available on acceptable terms, we would curtail our acquisition, drilling, development and other activities or could be forced to sell some of our assets on an untimely or unfavorable basis.

Our 2012 development plans in the Gulf of Mexico, as well as our longer term business plan, are dependent on receiving approval for deepwater drilling, pipeline installation and other permits submitted to the BOEM. While we believe we can satisfy the permitting requirements for our planned 2012 development wells, which we expect to allow us to increase our production from current levels, there is no assurance that they will be received in time to benefit our 2012 results or that permits will be issued in the future.

Our longer term liquidity is dependent on the prevailing prices for oil and natural gas, which have historically been very volatile. To mitigate price volatility, we expect to continue to hedge the sales price of a portion of our future production.

The U.S. governmental and regulatory response to the Deepwater Horizon drilling rig accident and resulting oil spill could have a prolonged and material adverse impact on our Gulf of Mexico operations.

Since May 2010 when the federal government imposed the first of a series of moratoriums on drilling in the Gulf of Mexico, we have faced unparalleled difficulties in obtaining permits to continue our development programs. Prior to the moratoriums, we anticipated developing and bringing to production three additional wells at our Telemark Hub and two additional wells at our Gomez Hub by the end of 2010. It has taken until the first quarter of 2012 for us to bring to production all of the three additional wells at the Telemark Hub and, during the third quarter of 2011, the two wells planned for the Gomez Hub were postponed to late 2012/early 2013 as the required permits had not yet been received.

The new wells that have been placed on production have taken longer to complete and bring to production than originally planned. In addition, we have incurred capital and operating costs higher than we expected primarily due to additional regulations imposed since the Deepwater Horizon incident. Additional adverse regulatory responses could have a material adverse impact on our financial position, results of operation and cash flows.

Delays in the development of or production curtailment at our material properties, including at our Telemark Hub, may adversely affect our financial position and results of operations.

The size of our operations and our capital expenditures budget limits the number of properties that we can develop in any given year. Complications in the development of any single major well or infrastructure installation may result in a material adverse effect on our financial condition and results of operations. For example, during 2011 and 2010, our operations were curtailed due to the imposition of the deepwater drilling moratoriums and permitting slowdown. During 2009, delays obtaining workover permits for an operation at our Gomez Hub pushed completion of the workover from the fourth quarter of 2009 to late January 2010.

In addition, relatively few wells contribute a substantial portion of our production. If we were to experience operational problems or adverse commodity prices resulting in the curtailment of production in any of these wells, our total production levels would be adversely affected, which would have a material adverse effect on our financial condition and results of operations.

Our actual development results are likely to differ from our estimates of our oil and gas reserves. We may experience production that is less than estimated and development costs that are greater than estimated in our reserve reports. Such differences may be material.

Estimates of our oil and natural gas reserves and the costs and timing associated with developing these reserves may not be accurate. Additionally, at December 31, 2011, approximately 77% of our total proved reserves are classified as undeveloped. Development of these reserves may not yield the expected results, or the development may be delayed or the development costs may exceed our estimates, any of which may materially affect our financial position and results of operations. Development activity may result in downward adjustments of reserves or higher than estimated costs.

Our estimates of our proved oil and natural gas reserves and the estimated future net revenues from such reserves are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise and the quality and reliability of this data can vary.

Any significant variance could materially affect the estimated quantities and values of our proved reserves. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we will likely adjust estimates of proved reserves to reflect production history, results of development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. Actual production, revenues, taxes, development expenditures and operating expenses with respect to our reserves may vary materially from our estimates.

We have significant debt, trade payables, other long-term obligations.

Our trade payables, other long-term obligations and related interest payment requirements and scheduled debt maturities may have important negative consequences. For instance, they could:

- make it more difficult or render us unable to satisfy these or our other financial obligations;
- require us to dedicate a substantial portion of any cash flow from operations to the payment of overriding royalties or interest and principal due under our debt, which will reduce funds available for other business purposes;
- increase our vulnerability to general adverse economic and industry conditions;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- place us at a competitive disadvantage compared to some of our competitors that have less financial leverage; and
- limit our ability to obtain additional financing required to fund working capital and capital expenditures and for other general corporate purposes.

Our ability to overcome our negative working capital and to satisfy our financial obligations and commitments depends on our future operating performance and on economic, financial, competitive and other factors, many of which are beyond our control. We cannot provide assurance that our business will generate sufficient cash flow or that future financings will be available to provide sufficient proceeds to meet these obligations. The inability to meet our financial obligations and commitments will impede the successful execution of our business strategy and the maintenance of our economic viability.

Oil and natural gas prices are volatile, and low prices have had in the past and could have in the future a material adverse impact on our business.

Our revenues, profitability and future growth and the carrying value of our properties depend substantially on the prices we realize for our oil and natural gas production. Our realized prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital.

Historically, the markets for oil and natural gas have been volatile, and they are likely to continue to be volatile. For example, oil and natural gas prices increased significantly in late 2000 and early 2001 and then steadily declined in 2001. This phenomenon occurred again beginning in 2004 when oil prices began to climb and reached an all-time high in mid 2008. By the end of 2008, oil had lost nearly two-thirds of its value, dropping from a high of $146 per barrel in July 2008 to a close of $45 per barrel in December 2008. In February 2009, oil closed at its lowest price for the year of $33.98 per barrel. In 2011, oil climbed to $113.93 per barrel at one point. Among the factors that have caused and may continue to cause this volatility are:

- worldwide or regional demand for energy, which is affected by economic conditions;
- the domestic and foreign supply of oil and natural gas;
- volatility in the value of the U.S. dollar relative to other currencies;
- governmental regulations or lack of regulations around the world;
- the uncertainty of when the BOEM will issue permits for deepwater drilling;
- political conditions in oil or natural gas producing regions;
- the ability of the Organization of Petroleum Exporting Countries to agree upon and maintain oil prices and production levels;
- speculative trading in crude oil and natural gas derivative contracts;
- weather conditions; and
- price and availability of alternative fuels.

It is impossible to predict oil and natural gas price movements with certainty. Lower oil and natural gas prices may not only decrease our revenues on a per-unit basis but also may reduce the amount of oil and natural gas that we can produce economically. A substantial or extended decline in oil and natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity and ability to finance planned capital expenditures. Further, oil prices and natural gas prices do not necessarily move together.

Rapid growth may place significant demands on our resources.

We have experienced rapid growth in our operations and expect that significant expansion of our operations will continue. Our rapid growth has placed, and our anticipated future growth will continue to place, a significant demand on our managerial, operational and financial resources due to:

- the need to manage relationships with various strategic partners and other third parties;
- difficulties in hiring, managing and retaining skilled personnel necessary to support our rapid growth;
- the need to train and manage a growing employee base; and
- pressures for the continued development of our financial and information management systems.

If we have not made adequate allowances for the costs and risks associated with this expansion or if our systems, procedures or controls are not adequate to support our operations, our business could be adversely impacted.

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

Our success will depend on our ability to retain and attract experienced geoscientists and other professional staff. As of December 31, 2011, we had 27 engineers, geologist/geophysicists and other technical personnel in our Houston office, three engineers, geologist/geophysicists and other technical personnel in our U.K. location and one engineer in our Netherlands office. We depend to a large extent on the efforts, technical expertise and continued employment of these personnel and members of our management team. If a significant number of them resign or become unable to continue in their present role and if they are not adequately replaced, our business operations could be adversely affected.

Our insurance coverage may not be sufficient to cover some liabilities or losses that we may incur.

We maintain insurance to protect the Company and its subsidiaries against losses arising out of our oil and gas operations. Our insurance includes coverage for physical damage to our offshore properties, general (third party) liability, workers compensation and employers liability, seepage and pollution and other risks. Our insurance includes various limits and deductibles or retentions, which must be met prior to or in conjunction with recovery. Additionally, our insurance is subject to the terms, conditions and exclusions of such policies. For losses emanating from offshore operations, we have up to an aggregate of $2.5 billion of various insurance coverages with individual policy limits ranging from $1.0 million to over $500 million each. While we maintain insurance levels, deductibles and retentions that we believe are prudent and responsible, there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages.

In general, our current insurance policies cover physical damage to our oil and gas assets. The coverage is designed to repair or replace assets damaged by insurable events.

Our excess liability policies generally provide coverage (dependent on the asset) for bodily injury and property damage, including coverage for negative environmental effects such as seepage and pollution. This liability coverage would cover claims for bodily injury or death brought against the company by or on behalf of individuals who are not employees of the company. The liability limits scale to either our operating interest or the total insured interest including nonoperating partners.

Our energy insurance package includes coverage for operator's extra expense, which provides coverage for control of well, re-drill and pollution arising from a covered event. We maintain a $150 million Oil Spill Financial Responsibility policy in order to provide a Certificate of Financial Responsibility to the BSEE under the requirements of the Oil Pollution Act of 1990. Additionally, as noted above, our excess liability policies provide coverage (dependent on the asset) for bodily injury and property damage, including coverage for negative environmental effects such as seepage and pollution. Legislation has been proposed but has not passed to increase the limit of the Oil Spill Financial Responsibility policy required for the certificate and there is no assurance that we will be able to obtain this insurance should that happen.

The occurrence of a significant accident or other event not fully covered by our insurance could have a materially adverse effect on our operations and financial condition. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance at levels that would provide enough funds for us to continue operating without access to other funds. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. Because third-party contractors and other service providers are used in our offshore operations, we may not realize the full benefit of worker's compensation laws in dealing with their employees. In addition, pollution and environmental risks generally are not fully insurable.

Our price risk management decisions may reduce our potential gains from increases in commodity prices and may result in losses.

We utilize commodity derivative instruments and fixed-price forward sales contracts with respect to a portion of our expected production in order to manage our exposure to oil and natural gas price volatility. These instruments expose us to risk of financial loss if:

- production is less than expected for forward sales contracts;
- the counterparty to the derivative instrument defaults on its contract obligations; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument or fixed-price forward sales contract and actual price received.

Our results of operations may be negatively impacted in the future by our derivative instruments and fixed-price forward sales contracts as these instruments may limit any benefit we would receive from increases in the prices for oil and natural gas.

Potential regulations under the Dodd-Frank Act regarding derivatives could adversely impact our ability to engage in commodity price risk management activities.

Periodically we enter into commodity derivative instruments as an economic hedge on a portion of our oil and natural gas sales. On July 21, 2010, Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), which imposes a comprehensive regulatory scheme significantly impacting companies engaged in over-the-counter ("OTC") swap transactions. The Dodd-Frank Act generally applies to "swaps" entered into by "major swap participants" and/or "swap dealers," each as defined in the Dodd-Frank Act. A swap is very broadly defined in the Dodd-Frank Act and includes an energy commodity swap. A swap dealer includes an entity that regularly enters into swaps with counterparties as an "ordinary course of business for its own account." Furthermore, a person may qualify as a major swap participant if it maintains a "substantial position" in outstanding swaps, other than swaps used for "hedging or mitigating commercial risk" or whose positions create substantial exposure to its counterparties or the U.S. financial system. The Dodd-Frank Act subjects swap dealers and major swap participants to substantial supervision and regulation by the U.S. Commodity Futures Trading Commission ("CFTC"), including capital standards, margin requirements, business conduct standards, and recordkeeping and reporting requirements. It also requires most regulated swaps to be cleared through a derivatives clearing organization ("DCO") registered with the CFTC. By clearing through a DCO, each party to a swap will be required to provide collateral to the DCO to settle, on a daily basis, any credit exposure resulting from fluctuations in market prices. The CFTC also has the authority to impose position limits on companies trading in OTC derivatives markets. Although the Dodd-Frank Act provides a framework for regulating OTC swap transactions, the substance of the Act will be set forth in numerous rules subsequently promulgated by the CFTC and other agencies. Because the CFTC has not yet clearly articulated the scope of key definitions in the Dodd-Frank Act, such as "swap," "swap dealer" and "major swap participant," and because the parameters of Dodd-Frank Act requirements are still shifting, it is impossible to know exactly how the Dodd-Frank Act will impact our business. However, the issuance of any rules or regulations relating to the Dodd-Frank Act that subject us to additional business conduct standards, position limits and/or reporting, capital, margin or clearing requirements with respect to our energy commodity swap risk management positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activities. If we are required to post collateral as a result of new rules, we would have to do so by utilizing cash or letters of credit, to the extent allowed by our credit agreements, which would reduce our liquidity position and increase costs. These changes could materially reduce our hedging opportunities and increase the costs associated with our hedging programs, both of which could negatively affect our cash flow.

The unavailability or increased cost of drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute on a timely basis our development plans and abandonment operations within our budget.

Shortages or increases in the cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our operations, which could have a material adverse effect on our business, financial condition and results of operations. Changes in the level of drilling activity in the Gulf of Mexico and the North Sea affects the availability of offshore rigs and associated equipment. In periods of increased drilling activity in the Gulf of Mexico and the North Sea, we may experience increases in associated costs, including those related to drilling rigs, equipment, supplies and personnel and the services and products of other vendors to the industry. These costs may increase further and necessary equipment and services may not be available to us at economical prices. For the years ended December 31, 2011, 2010 and 2009, we recorded losses on abandonment of $3.9 million, $4.8 million and $2.9 million, respectively, primarily as a result of unanticipated increases in service costs in the Gulf of Mexico.

We may suffer losses as a result of foreign currency fluctuations.

The net assets, net earnings and cash flows from our wholly owned subsidiaries in the U.K., Israel and the Netherlands are based on the U.S. dollar equivalent of such amounts measured in the applicable local currency. These foreign operations have the potential to impact our financial position due to fluctuations in foreign currency exchange rates. Any increase in the value of the U.S. dollar in relation to the value of the local currency will adversely affect our revenues from our foreign operations when translated into U.S. dollars. Similarly, any decrease in the value of the U.S. dollar in relation to the value of the local currency will increase our development costs in our foreign operations, to the extent such costs are payable in foreign currency, when translated into U.S. dollars. Included in the net assets of one of our foreign subsidiaries are significant amounts for assets under construction in China, the obligations for which are denominated in local currency and which therefore present us with additional exposure to currency fluctuations. We currently have no derivatives or other financial instruments in place to hedge the risk associated with the movement in foreign currency exchange rates.

The oil and natural gas business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

Our development activities may be unsuccessful for many reasons, including cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of an oil or natural gas well does not ensure a profit on investment. A variety of factors, both technical and market-related, can cause a well to become uneconomic or only marginally economic. In addition to their cost, unsuccessful wells can hurt our efforts to replace reserves.

The oil and natural gas business involves a variety of operating risks, including:

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

If we experience any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, which could adversely affect our ability to conduct operations. We could also incur substantial losses in excess of our insurance coverage as a result of:

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

Offshore operations are also subject to a variety of operating risks peculiar to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for development or leasehold acquisitions, or result in loss of equipment and properties.

Our Gulf of Mexico properties are subject to rapid production declines. Therefore, we are required to replace our reserves at a faster rate than companies whose onshore reserves have longer production periods. We may not be able to identify or complete the acquisition of properties with sufficient proved reserves to implement our business strategy.

Reservoirs in the Gulf of Mexico are typically prolific producers due to their high permeability and efficient completions. Reserves can therefore be produced rapidly. As of December 31, 2011, we project normalized annual decline rates of 19% for oil and 17% for gas in our Gulf of Mexico deepwater fields. While this results in recovery of a relatively higher percentage of reserves from Gulf of Mexico properties during the initial years of production, we must incur significant capital expenditures to replace declining production.

We may not be able to identify or complete the acquisition of properties with sufficient reserves or reservoirs to implement our business strategy. As we produce our existing reserves, we must identify, acquire and develop properties through new acquisitions or our level of production and cash flows will be adversely affected. The availability of properties for acquisition depends largely on the divesting practices of other oil and natural gas companies, commodity prices, general economic conditions and other factors that we cannot control or influence. A substantial decrease in the availability of oil and gas properties that meet our criteria in our areas of operation, or a substantial increase in the cost to acquire these properties, would adversely affect our ability to replace our reserves.

We may incur substantial impairment write-downs.

We account for our oil and gas property costs using the successful efforts accounting method. Under the successful efforts method, lease acquisition costs and intangible drilling and development costs on successful wells and development dry holes are capitalized. Costs of drilling exploratory wells are initially capitalized, but charged to expense if and when a well is determined to be unsuccessful.

If management's estimates of the recoverable reserves on a property are revised downward, if development costs exceed previous estimates or if oil and natural gas prices decline, we may be required to record additional noncash impairment write-downs in the future, which would result in a negative impact to our financial position and earnings. We review our proved oil and gas properties for impairment on a depletable unit basis whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management's estimates of future oil and gas prices to the estimated future production of oil and gas reserves over the economic life of the property and deducting estimated future operating and development costs. Future net cash flows are based upon reservoir engineers' estimates of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions and actual or planned drilling or other development activities. For a property determined to be impaired, an impairment loss equal to the excess of the carrying value over the estimated fair value of the impaired property will be recognized. Fair value, on a depletable unit basis, is estimated to be the present value of the aforementioned expected future net cash flows. Any impairments of proved properties are aggregated in accumulated depletion, depreciation, amortization and impairment, and reduce our basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units' estimated reserves, future net cash flows and fair value. We recorded impairments during the years ended December 31, 2011, 2010 and 2009 totaling $53.0 million, $42.4 million and $44.6 million, respectively, on certain proved properties in the Gulf of Mexico. We also recorded impairments totaling $14.9 million during 2010, on certain proved properties in the North Sea.

Impairments of unproved properties were $3.4 million, $6.0 million and $1.2 million in 2011, 2010 and 2009, respectively, primarily related to surrendered leases in the Gulf of Mexico.

Management's assumptions in calculating oil and gas reserves or estimating the future cash flows or fair value of our properties are subject to change at any time as economic conditions change. Changes in reserve volumes or commodity price forecasts will directly impact our estimates of future cash flows and property fair values. Adverse changes in these variables could result in the recognition of impairment expense, which would reduce our net income (or increase a net loss) and reduce our basis in the related asset.

We may be unable to identify liabilities associated with the properties that we acquire or obtain protection from sellers against them.

Acquiring oil and gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well, platform or pipeline. We cannot necessarily observe structural and environmental problems, such as pipeline corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Competition in our industry is intense, and we are smaller than some of our competitors in the Gulf of Mexico and in the North Sea.

We compete with major and independent oil and natural gas companies for property acquisitions. We also compete for the equipment and labor required to operate and to develop our properties. Some of our competitors have substantially greater financial and other resources than we do. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for oil and natural gas properties and may be able to define, evaluate, bid for and acquire a greater number of properties than we can. Our ability to acquire additional properties and develop new and existing properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Members of our management team own a significant amount of common stock, giving them influence in corporate transactions and other matters, and the interests of these individuals could differ from those of other shareholders.

Members of our management team beneficially own approximately 14% of our outstanding shares of common stock at March 2, 2012. As a result, these shareholders are in a position to significantly influence the outcome of matters requiring a shareholder vote, including the election of directors, the adoption of an amendment to our certificate of formation and the approval of mergers and other significant corporate transactions. Their influence may delay or prevent a change of control and may adversely affect the voting and other rights of other shareholders.

Terrorist attacks or similar hostilities may adversely impact our results of operations.

The terrorist attacks that took place in the U.S. on September 11, 2001 were unprecedented events that have created many economic and political uncertainties, some of which may materially adversely impact our business. Uncertainty surrounding military strikes or a sustained military campaign may affect our operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly oil markets, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or indirect casualties of, an act of terror or war. The continuation of these developments may subject our operations to increased risks and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations, financial condition and prospects. Additionally, we could be affected adversely by direct cyber attacks against our information systems.

We are subject to complex laws and regulations, including environmental regulations that can adversely affect the cost, manner or feasibility of doing business.

As discussed above, development, production and sale of oil and natural gas in the Gulf of Mexico and in the North Sea are subject to extensive laws and regulations, including environmental laws and regulations. We may be required to make large expenditures to comply with environmental and other governmental regulations.

Under these laws and regulations, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that substantially increase our costs. Accordingly, any of these liabilities, penalties, suspensions, terminations or regulatory changes could materially adversely affect our financial condition and results of operations.

Legislation and regulations pertaining to climate change and greenhouse gas emissions have the potential to materially adversely impact our business, financial condition, results of operations and cash flows, including costs of compliance and permitting delays. The extent and magnitude of these adverse impacts cannot be reliably or accurately estimated at this time because specific regulatory and legislative requirements have not been finalized and uncertainty exists with respect to the measures being considered, the costs and the time frames for compliance, and our ability to pass compliance costs on to our customers.

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

Periodically, legislation is introduced to eliminate certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. Such 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 certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Several of these changes were included in White House budget proposals released on February 26, 2009, February 1, 2010, February 14, 2011 and February 13, 2012, and may be raised again in the future. Additionally, since the first White House proposal multiple bills have been proposed in Congress to implement many of these changes. It is unclear, however, whether any of these changes will be enacted or how soon they could be effective.

Our ability to use our net operating losses to offset our future taxable income may be severely limited under Section 382 of the Internal Revenue Code.

Section 382 of the Internal Revenue Code of 1986, as amended (the "I.R.C."), generally limits the ability of a corporation that undergoes an "ownership change" to utilize its net operating loss carryforwards ("NOLs") and certain other tax attributes against future taxable income in periods after the ownership change. The amount of taxable income in each tax year after the ownership change that may be offset by pre-change NOLs and certain other pre-change tax attributes is generally equal to the product of (a) the fair market value of the corporation's outstanding stock immediately prior to the ownership change and (b) the long-term tax exempt rate (i.e., a rate of interest established by the Internal Revenue Service that fluctuates from month to month.) In general, an "ownership change" occurs whenever the percentage of the stock of a corporation owned, directly or indirectly, by "5-percent stockholders" (within the meaning of Section 382 of the I.R.C.) increases by more than 50 percentage points over the lowest percentage of the stock of such corporation owned, directly or indirectly, by such "5-percent stockholders" at any time over the preceding three years.

Our NOLs and certain other tax attributes are subject to an annual limitation as a result of an ownership change we experienced in November 2007. Additional ownership changes could further reduce our annual NOL limitation if our equity value at the time of the ownership changes is significantly below our equity value as of the date of the November 2007 ownership change. Issuances of our stock, sales or other dispositions of our stock by certain significant stockholders, certain acquisitions of our stock and issuances, sales or other dispositions or acquisitions of interests in certain significant stockholders could trigger additional ownership changes. We have little or no control over any such events. If additional ownership changes occur, any further limitation on our use of NOLs and certain other tax attributes to offset our taxable income could result in a significant increase in our future income tax payments, and could negatively affect our financial condition, results of operation and our ability to make payments on our outstanding indebtedness.

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

None

Item 2. ***Properties.***

General

We are engaged in the acquisition, development and production of oil and natural gas properties in the Gulf of Mexico and the North Sea. At December 31, 2011, in the Gulf of Mexico, we owned leasehold and other interests in 38 offshore blocks and 49 wells, including 23 subsea wells. We operate 43 (88%) of these wells, including 100% of the subsea wells. In the North Sea, we also had interests in 13 blocks and two company-operated subsea wells. Our average working interest in our properties at December 31, 2011 was approximately 81%. As of December 31, 2011, we had leasehold interests and licenses located in the Gulf of Mexico, North Sea and East Mediterranean (discussed below) covering approximately 588,459 gross (348,109 net acres) of which 159,658 gross acres (111,226 net acres) were developed.

As of the date of this report, we own an interest in 13 platforms including two floating production facilities in the Gulf of Mexico, the *ATP Titan* at our Telemark Hub and the *ATP Innovator* at our Gomez Hub. These floating production facilities are fundamental to our hub strategy and business plan. The presence of these facilities allows us a competitive advantage for additional acquisitions in a large area surrounding each installation. A third floating production facility called an Octabuoy is under construction in China for initial deployment at our Cheviot Hub in the U.K. North Sea which is expected in 2014. We operate the *ATP Innovator* and the *ATP Titan* and we also expect to operate the Octabuoy when it is placed in service. The floating production facilities have longer useful lives than the underlying reserves and are capable of redeployment to new producing locations upon depletion of the reserves. Accordingly, they are expected eventually to be moved several times over their useful lives.

During 2011, we acquired three licenses in the East Mediterranean covering potential natural gas resources in the deepwater off the coast of Israel. In the East Mediterranean our licenses relate to exploratory prospects where drilling has occurred nearby and hydrocarbons have been discovered by others. Our capital investment in the East Mediterranean related to these three licenses was minimal for 2011 and we are preparing our exploration and development plans for drilling in 2012.

Gulf of Mexico

Acquisitions – During November and December 2011, we acquired an aggregate additional 45% interest in Green Canyon Block 300 ("GC") from former partners in the project. We now operate that property with a 100% working interest.

Dispositions – During December 2011, we sold to a third party our 100% working interest in the deep operating rights of one of our Gulf of Mexico properties resulting in substantially all of the $27.0 million gain on disposal of properties we recognized in 2011.

Development – In 2011, we achieved first production from MC Block 941 A-2 located in our Telemark Hub which utilizes the *ATP Titan* floating production platform. The well was completed at a measured depth of 17,600 feet. We have also completed at a vertical depth of 17,220 feet and achieved first production in February 2012 at the fourth Telemark Hub well at MC Block 942 A-3. We are the operator and have a 100% working interest in the Telemark Hub. At Green Canyon 300 ("Clipper," ATP operated), we successfully completed two wells located in approximately 3,500 feet of water and at a measured depth of approximately 16,000 feet. The wells are currently completed and shut in. We expect first production in the latter part of 2012 after installation of a pipeline from the wells to a host facility. In June 2011, we completed and returned to production the MC Block 711 #5 well bringing to six the number of wells producing at our Gomez Hub.

North Sea - Development

During 2011, the work on the Octabuoy floating production facility continued in the shipyard. Platform topsides are under construction in China (the utility module) and the U.S. (the processing module). Upon completion of the processing module it will be shipped to China to be joined with the utility module. The hull and topsides will then sail to Norway for final commissioning and on to the Cheviot field in the North Sea where production is expected to begin in 2014.

In addition to Cheviot, we are working on our Skipper and Blythe projects in the U.K. North Sea. At Skipper, an oil project, an appraisal well to test production rates is scheduled for next year. At Blythe, predominately a gas project, discussions are ongoing to determine the most economic offtake route for the gas from this field. Development at Blythe is expected to commence in 2012. Skipper is located in the central U.K. North Sea in water depths of approximately 300 feet. Blythe is located in the Southern Gas Basin in water depths of approximately 100 feet. We operate both Skipper and Blythe and have a 50% working interest ownership in each.

Israel – Exploration

During June 2011, through our subsidiary, ATP East Med B.V., we acquired interests in three deepwater licenses in the Mediterranean Sea offshore Israel for $1.7 million. We will operate our licenses, Shimshon, Daniel East and Daniel West, which are exploratory prospects where drilling has occurred nearby and hydrocarbons have been discovered by others. We anticipate initial drilling during the second quarter of 2012 and expect to spend between $24 and $29 million during 2012 related to the initial exploratory well on the Shimshon license.

Oil and Natural Gas Reserves

References below to various classifications of oil and natural gas reserves have the meanings set forth under the caption "Certain Definitions" at the front of this report.

Our business strategy is to acquire proved reserves, typically undeveloped, and to begin producing those reserves as rapidly as possible. Occasionally we will acquire properties where previous drilling has encountered reservoirs that appear to contain economically productive quantities of oil and gas even though the reservoirs do not meet the SEC definition of proved reserves.

The following table presents our estimated net proved oil and natural gas reserves (all from traditional resources) at December 31, 2011 based on reserve reports prepared by independent petroleum engineers Collarini Associates and Ryder Scott Company, L.P. for our Gulf of Mexico reserves and Collarini Associates for our U.K. reserves. The technical personnel responsible for preparing the reserve estimates at both Collarini Associates and Ryder Scott Company, L.P. meet the requirements regarding qualifications, independence, objectivity, and confidentiality 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 independent firms of petroleum engineers, geologists, geophysicists, and petrophysicists; they do not own an interest in our properties and are not employed on a contingent fee basis.

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
Gulf of Mexico			
Oil and NGL (MBbls)	18,590	34,351	52,941
Natural gas (MMcf)	46,309	91,729	138,038
Total proved reserves (MBoe)	26,308	49,640	75,948
North Sea			
Oil and NGL (MBbls)	6	25,667	25,673
Natural gas (MMcf)	5,940	97,519	103,459
Total proved reserves (MBoe)	996	41,921	42,917

Total			
Oil and NGL (MBbls)	18,596	60,018	78,614
Natural gas (MMcf)	52,249	189,248	241,497
Total proved reserves (MBoe)	27,304	91,561	118,865

Our corporate reservoir engineering group has oversight and compliance responsibility for the internal reserve estimation process and provides data to the independent third-party engineers who estimate our reserves. The management of this group, which includes the Chief Operating Officer, consists of a degreed petroleum engineer with 29 years of industry experience, including 13 years of experience managing ATP's reserves. Annually, this petroleum engineer attends continuing technical education courses. He is a 27-year member of the Society of Petroleum Engineers.

The estimates of proved reserves in the table above do not differ from those we have filed with other federal agencies. The process of estimating oil and natural gas reserves is complex. It requires various assumptions, including assumptions relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. We must project production rates and timing of development expenditures. We analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling and completion operations. Although the reserves and the costs associated with developing them are estimated in accordance with SEC standards, the estimated costs may be inaccurate, development may not occur as scheduled and results may not be as estimated. Therefore, estimates of oil and natural gas reserves are inherently imprecise. Estimates of reserves may increase or decrease as a result of future operations.

Proved Undeveloped Reserves ("PUDs")

As of December 31, 2011, our PUDs totaled 60.0 MMBbls of crude oil and 189.2 Bcf of natural gas, for a total of 91.6 MMBoe. As of December 31, 2010, our PUDs totaled 61.5 MMBbls of crude oil and 246.8 Bcf of natural gas, for a total of 102.6 MMBoe. The 11.1 MMBoe decrease in PUDs in 2011 is primarily due to: (i) a net 6.8 MMBoe decrease at our Telemark Hub related to the conversion of the MC Block 941 A-2 well to proved developed producing and other revisions to the existing PUDs; (ii) the conversion of 3.9 MMBoe of PUDs into proved developed reserves at our Clipper Field; (iii) the write-off of 1.4 MMBoe related to South Timbalier Block 77 due to lease expiration; (iv) upward revisions of 1.0 MMBoe at various properties. Costs incurred relating to the development of PUDs in 2011 were approximately $506 million, excluding capitalized interest. Approximately 47% of our PUDs at December 31, 2011 were associated with our major development hubs at Telemark and Gomez in the Gulf of Mexico. We had planned to convert additional reserves to proved developed during 2011 at these two hubs, however due to delays in obtaining drilling permits, some of those expected conversions are delayed into 2012 and beyond. An additional 42% of PUDs at December 31, 2011 were associated with an active development project at the Cheviot field in the U.K. sector of the North Sea discussed further below.

At December 31, 2011, the reserves at our Cheviot field which were first booked in 2005 have been classified as undeveloped for more than five years. This field is in the northern part of the North Sea in a water depth of over 500 feet. Our original development plan for the field included the use of a concrete structure platform; however due to environmental regulations in the European Union imposed after acquisition of Cheviot, this type of structure was subsequently disallowed in the North Sea and our development plan had to be modified to utilize a floating production platform. With the knowledge of the U.K. Department of Energy and Climate Change, the development of the field was delayed while we modified our development plan to engineer and incorporate the floating structure into our plans. In late 2008, we contracted with a shipyard in China and commenced construction of the floating production platform. The hull of the platform is now approximately 90% complete and construction of the topsides is also underway. The remaining construction of the platform, installation of the pipelines and drilling of the wells will require the next two years to complete, allowing expected first production to take place in 2014. During 2011, ATP incurred costs of approximately $209 million related to this project bringing the total in excess of $492 million through December 31, 2011 and we remain committed to this development.

Standardized Measure of Cash Flows

At December 31, 2011 our standardized measure of discounted future net cash flows was $3.5 billion. The present value of future net pre-tax cash flows attributable to estimated net proved reserves, discounted at 10%

per annum, ("PV-10") is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. The table below provides a reconciliation of PV-10 to the standardized measure of discounted future net cash flows at December 31, 2011. PV-10 may be considered a non-GAAP financial measure under the SEC's regulations. PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes. We further believe investors and creditors may utilize our PV-10 as a basis for comparison of the relative size and value of our reserves to other companies. However, PV-10 is not a substitute for the standardized measure. Our PV-10 measure and the standardized measure of discounted future net cash flows (shown below in thousands) do not purport to present the fair value of our oil and natural gas reserves.

PV-10	$ 4,200,877
Future income taxes, discounted at 10%	(669,953)
Standardized measure of discounted future net cash flows	$ 3,530,924

Significant Properties

The following table sets forth reserve information on our more significant properties as of December 31, 2011 and related net production for the years indicated:

Field	Development Location	Net Total Proved Reserves MBoe	Net Total Proved Undeveloped Reserves MBoe	2011 Net Production MBoe	2010 Net Production MBoe	2009 Net Production MBoe
Telemark Hub (1)	GOM	38,810	27,599	3,943	1,356	–
Gomez Hub (1)	GOM	19,506	15,644	2,983	3,132	2,709
Cheviot (2)	N. Sea	38,899	38,899	–	–	–
		97,215	82,142	6,926	4,488	2,709
Total Company		118,865	91,561	8,988	7,663	5,873

(1) Contains shut-in reserves and/or undeveloped reserves a portion of which are scheduled to be produced in 2012.
(2) First production is expected in 2014.

Drilling Activity

The following table shows our drilling activity for the three years ended December 31, 2011. In the table, "gross" refers to the total wells in which we have a working interest and "net" refers to gross wells multiplied by our working interest in such wells.

	Gulf of Mexico			North Sea		
	2011	2010	2009	2011	2010	2009
Gross Development Wells:						
Productive (1)	4.0	2.0	2.0	–		2.0
Nonproductive	–	–	–	–	–	–
Total	4.0	2.0	2.0	–		2.0
Net Development Wells:						
Productive (1)	4.0	2.0	1.6	–	–	0.4
Nonproductive	–	–	–	–	–	–
Total	4.0	2.0	1.6	–		0.4
Gross Exploratory Wells (2):						
Productive	–	–	–	–	1.0	–
Nonproductive	–	–	–	–	–	–
Total	–	–	–	–	1.0	–
Net Exploratory Wells (2):						
Productive	–	–	–	–	0.2	–
Nonproductive	–	–	–	–	–	–
Total	–	–	–	–	0.2	–
Total Gross Wells:						
Productive	4.0	2.0	2.0	–	1.0	2.0
Nonproductive	–	–	–	–	–	–
Total	4.0	2.0	2.0	–	1.0	2.0
Total Net Wells:						
Productive	4.0	2.0	1.6	–	0.2	0.4
Nonproductive	–	–	–	–	–	–
Total	4.0	2.0	1.6	–	0.2	0.4

(1)At December 31, 2011, one gross (one net) development well was in the completion phase and subsequently began production in February of 2012.

(2)During 2010, in addition to one gross (0.2 net) productive exploratory well, we also drilled two gross exploratory wells (0.3 net wells) in the North Sea which are still being evaluated.

Productive Wells

The following table presents the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2011:

	Gulf of Mexico	North Sea	Total
Gross			
Oil	17.0	–	17.0
Natural gas	16.0	9.0	25.0
Total	33.0	9.0	42.0
Net			
Oil	13.0	–	13.0
Natural gas	14.3	2.0	16.3
Total	27.3	2.0	29.3

At December 31, 2011, we had one gross natural gas well with multiple completions.

Acreage

The following table summarizes our developed and undeveloped acreage holdings at December 31, 2011. Acreage in which ownership interest is limited to royalty, overriding royalty and other similar interests is excluded (in acres):

	Developed (1)		Undeveloped (2)		Total	
	Gross	Net	Gross	Net	Gross	Net
Gulf of Mexico	117,272	100,486	97,160	93,146	214,432	193,632
North Sea	42,386	10,740	42,157	27,943	84,543	38,683
East Mediterranean	–	–	289,484	115,794	289,484	115,794
Total	159,658	111,226	428,801	236,883	588,459	348,109

(1) Developed acres are acres spaced or assigned to productive wells.
(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains proved reserves.

The terms of leases and licenses on undeveloped acreage are scheduled to expire as shown in the table below for the full-year periods indicated. The term of a lease may be extended by drilling or production operations.

	Gulf of Mexico		North Sea		East Mediterranean		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2012	23,040	21,600	20,347	17,038	98,842	39,537	142,229	78,175
2013	11,520	11,520	21,810	10,905	–	–	33,330	22,425
2014	–	–	–	–	190,642	76,257	190,642	76,257
2015 & beyond	62,600	60,026	–	–	–	–	62,600	60,026
Total	97,160	93,146	42,157	27,943	289,484	115,794	428,801	236,883

The Gulf of Mexico leases expiring in 2012 include 17,280 gross (15,840 net) acres that should be held by activity or production beyond their stated expiration date.

The North Sea leases expiring in 2012 include 11,703 gross and net acres related to proved reserves which are actively being developed and as such the lease term will be extended beyond the stated expiration.

The East Mediterranean licenses expiring in April 2012 include 98,842 gross (39,537 net) acres related to unproved acreage which is actively under development, and as such the license term will be extended beyond the stated expiration.

Production and Pricing Data

See additional information on production and pricing contained in Item 7. – "Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations".

Item 3. *Legal Proceedings.*

On January 29, 2010, Bison Capital Corporation ("Bison") filed suit against ATP in the United States District Court for the Southern district of New York alleging ATP owed fees totaling $102 million to Bison under a February 2004 agreement. The case was tried in January 2011. On March 8, 2011 the Court entered a judgment in favor of Bison for $1.65 million plus prejudgment interest and Bison's reasonable attorney's fees. ATP provided for this judgment in the financial statements as of December 31, 2010 and 2011. Either party could file a notice of appeal within 30 days of the judgment. Subsequently, Bison gave notice that it would appeal the judgment. By September 16, 2011, both Bison and ATP filed their respective briefs with the United States Court of Appeals for the Second Circuit. The case remains active pending resolution by the appellate court.

Item 4. *Mine Safety Disclosures*

Not applicable.

PART II

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

Our authorized capital stock consists of 100,000,000 shares of common stock, par value $0.001 per share, and 10,000,000 shares of preferred stock, par value $0.001 per share. There were 52,051,422 shares of common stock and 3,105,000 shares of 8% convertible perpetual preferred stock outstanding as of March 2, 2012. Our common stock is traded on the NASDAQ Global Select Market under the ticker symbol ATPG. The number of holders of our common stock and 8% convertible perpetual preferred stock as of March 8, 2012 is 12,321 and 556, respectively. The following table sets forth the range of high and low sales prices for our common stock as reported on the NASDAQ Global Select Market for the periods indicated below. Such over-the-counter market quotations reflect inter-dealer prices, without retail mark-up, mark-down or commission and may not necessarily represent actual transactions.

	High	Low
2010		
1st Quarter	$ 20.57	$ 12.72
2nd Quarter	23.97	8.16
3rd Quarter	14.73	8.85
4th Quarter	17.44	13.05
2011		
1st Quarter	$ 21.40	$ 15.50
2nd Quarter	19.13	14.40
3rd Quarter	16.23	6.26
4th Quarter	11.85	5.53

We have never declared or paid cash dividends on our common stock. We currently intend to retain future earnings and other cash resources, if any, for the operation and development of our business and do not anticipate paying cash dividends on our common stock in the foreseeable future. Payment of any future dividends will be at the discretion of our board of directors after taking into account many factors, including our financial condition, operating results, current and anticipated cash needs and plans for expansion. In addition, our current long-term debt limits the amount we can pay for cash dividends on our common stock. Further discussion of these restrictions is set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Long-term Debt" and in Note 6, "Long-term Debt" of the Notes to Consolidated Financial Statements. Any future dividends may also be restricted by any loan agreements which we may enter into from time to time. We pay quarterly dividends on outstanding shares of our convertible preferred stock at the annual rate of 8% of liquidation value.

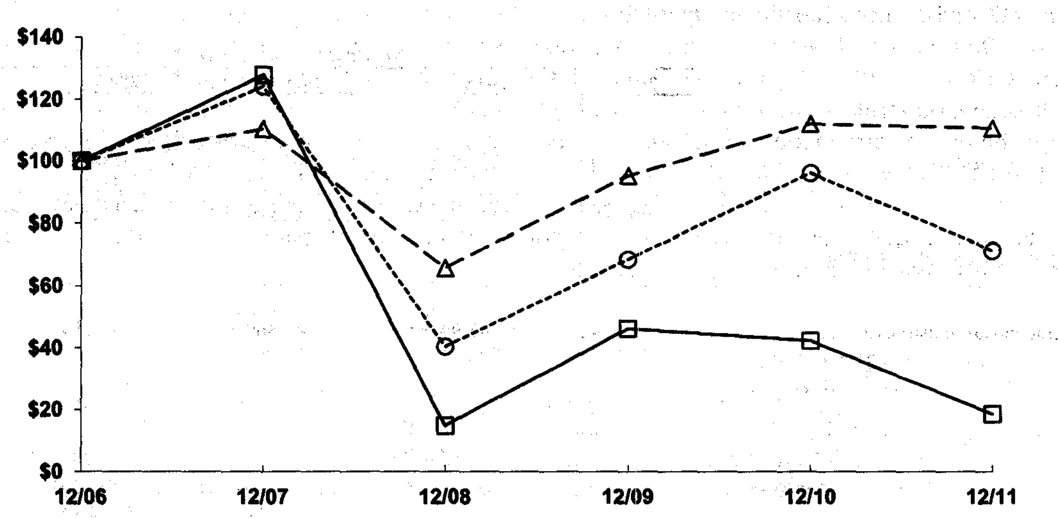
Shareholder Return Performance Presentation

The information set forth in the graph and table below compares the value of our Common Stock to the NASDAQ Composite Index and a "Peer Group Index" which is comprised of independent oil and gas exploration and production companies with operations and assets focused in the Gulf of Mexico region. Our Peer Group Index includes only companies of similar size, geographic and strategic focus that would possess similar prospects for favorable stock price performance: Callon Petroleum Company, Energy Partners, Ltd., Forest Oil Corporation (since June 2007), Helix Energy Solutions Group, Newfield Exploration Company, Plains Exploration & Production (since November 2007) and Stone Energy Corporation.

Each of the total cumulative returns presented assumes a $100 investment beginning December 31, 2006 and ending December 31, 2011. The performance of the indices is shown on a total return (dividend reinvestment) basis; however, we paid no dividends on our Common Stock during the period shown. The graph lines merely connect the beginning and end of the measuring periods and do not reflect fluctuations between those dates.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among ATP Oil & Gas Corporation, the NASDAQ Composite Index, and Peer Group Index



*$100 invested on 12/31/06 in stock or index, including reinvestment of dividends.
Fiscal year ended December 31.

Total Return Analysis	12/31/06	12/31/07	12/31/08	12/31/09	12/31/10	12/31/11
ATP Oil & Gas Corporation	$100.00	$127.72	$14.78	$46.20	$42.30	$18.60
NASDAQ Composite Index	100.00	110.26	65.65	95.19	112.10	110.81
Peer Group Index	100.00	124.01	40.35	68.39	96.10	71.25

The foregoing graph and related description shall not be deemed incorporated by reference into any filing under the Securities Act of 1933, as amended, or under the Exchange Act, except to the extent that we specifically incorporate this information by reference. In addition, the foregoing graph and the related description shall not be deemed "soliciting material" or to be "filed" with the SEC or subject to Regulation 14A or 14C under the Exchange Act.

Information relating to compensation plans under which our equity securities are authorized for issuance is set forth in Part III, Item 12 of this Annual Report on Form 10-K.

Item 6. *Selected Financial Data.*
(In thousands, except per share data)

The following data should be read in conjunction with "Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations".

	Year Ended December 31,				
	2011	2010	2009	2008	2007
Statement of Operations Data:					
Revenues:					
Oil and gas production	$ 687,208	$ 437,997	$ 298,490	$ 584,823	$ 599,324
Other (1)	–	–	13,664	33,206	8,611
	687,208	437,997	312,154	618,029	607,935
Cost, operating expenses and other:					
Lease operating	122,202	132,544	84,956	91,196	91,693
Exploration	1,251	1,174	264	48	13,756
General and administrative	43,242	43,948	43,469	41,554	28,312
Depreciation, depletion and amortization	298,574	220,657	152,780	246,434	247,378
Impairment of oil and gas properties	57,639	63,267	45,799	125,059	34,342
Accretion of asset retirement obligation	15,000	13,827	11,676	15,566	12,117
Drilling interruption costs (2)	19,691	23,647	–	–	–
Loss on abandonment	3,916	4,829	2,872	13,289	18,649
Gain on exchange/disposal of properties(3)	(27,000)	(26,720)	(12,433)	(119,233)	–
	534,515	477,173	329,383	413,913	446,247
Income (loss) from operations	152,693	(39,176)	(17,229)	204,116	161,688
Other income (expense):					
Interest income	223	696	710	3,476	7,603
Interest expense, net	(326,411)	(222,104)	(40,884)	(100,729)	(121,302)
Derivative income (expense)	25,191	(22,419)	(712)	89,035	–
Gain (loss) on debt extinguishment	1,095	(75,316)	–	(24,220)	–
	(299,902)	(319,143)	(40,886)	(32,438)	(113,699)
Income (loss) before income taxes	(147,209)	(358,319)	(58,115)	171,678	47,989
Income tax (expense) benefit	(18,068)	36,273	22,534	(49,973)	631
Net income (loss)	(165,277)	(322,046)	(35,581)	121,705	48,620
Less income attributable to the redeemable noncontrolling interest (4)	(26,622)	(15,503)	(13,380)	–	–
Less convertible preferred stock dividends	(18,583)	(11,248)	(2,856)	–	–
Net income (loss) attributable to common shareholders	$ (210,482)	$ (348,797)	$ (51,817)	$ 121,705	$ 48,620
Net income (loss) per share attributable to common shareholders:					
Basic	$ (4.12)	$ (6.88)	$ (1.24)	$ 3.43	$ 1.58
Diluted	$ (4.12)	$ (6.88)	$ (1.24)	$ 3.39	$ 1.55
Preferred stock cash dividends per share:	$ 8.00	$ 8.05	$ 2.04	$ –	$ –
Weighted average number of common shares:					
Basic	51,077	50,715	41,853	35,457	30,793
Diluted	51,077	50,715	41,853	35,868	31,301

	December 31,				
	2011	2010	2009	2008	2007
Balance Sheet Data:					
Cash and cash equivalents	$ 65,678	$ 154,695	$ 108,961	$ 214,993	$ 199,449
Working capital (deficit)	(347,472)	(106,139)	(26,394)	36,459	96,888
Oil and gas properties, net	3,137,421	2,904,636	2,485,772	1,872,203	1,830,580
Total assets	3,388,774	3,290,102	2,803,147	2,275,610	2,307,133
Long-term debt, including current maturities	2,010,005	1,879,409	1,216,685	1,366,630	1,404,011
Other long-term obligations	451,797	472,500	274,942	2,582	–
Capital lease, including current maturities	–	–	–	–	–
Total liabilities	3,106,565	2,897,265	2,067,618	1,959,261	1,997,267
Temporary equity (4)	185,875	140,851	139,598	–	–
Shareholders' equity	96,334	251,986	595,931	316,349	309,866

(1) Other revenues are comprised of amounts realized under our loss of production income insurance policy as a result of disruptions caused by the 2008 and 2005 hurricanes.

(2) Drilling interruption costs reflect the costs we have incurred as a result of the deepwater drilling moratoriums and subsequent drilling permit delays caused by the April 2010 Deepwater Horizon incident in the Gulf of Mexico.

(3) Gain on exchange/disposition of properties consists of sales of the deep rights on Gulf of Mexico properties in 2011, 2010 and 2009, a Gulf of Mexico property exchange in 2010, and our sale of 80% of our working interest in Tors and Wenlock in the U.K. North Sea in 2008.

(4) Represents the 49% redeemable noncontrolling interest in our consolidated limited partnership that holds the *ATP Innovator* floating production facility. Temporary equity also includes that portion of the Series B Preferred Stock for which, in the event of certain fundamental changes, as defined in the statement of resolutions, the Company could be required to issue in the aggregate more shares of common stock pursuant to the conversion ratio most favorable to the holders than currently are authorized and unissued.

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

Executive Overview

Review of 2011

The year 2011 has been challenging for us. As we began 2011 the moratoriums on drilling in the Gulf of Mexico had been lifted but there had been no permits issued for new deepwater drilling to any company. We had two wells out of a scheduled four wells producing at our Telemark Hub and the prospects of receiving permits for the next two wells was uncertain. The drilling of two additional wells at our Gomez Hub had been deferred to future periods because of the moratoriums. Clearly, the moratoriums had impacted us.

On March 18, 2011 we received the third deepwater drilling permit granted by the BOEM after the end of the moratoriums and on March 31, 2011, we once again began drilling at our Telemark Hub. During the remainder of 2011 we received drilling permits for a second well at our Clipper project and our fourth well at our Telemark Hub. Other permits for workovers, side tracks, development and exploration at other projects have also been received in 2011. In summary, the total uncertainty surrounding permits in the Gulf of Mexico that ushered in 2011 had been replaced by a more reasonable flow and certainty for the permitting process. The deepwater Gulf of Mexico has once again opened for business.

We focus on deepwater drilling, development and production. While we had no ownership in the Macondo well and no direct costs associated with the Macondo well, we have been and continue to be negatively impacted by the drilling moratoriums. New rules and regulations have made it more expensive than in the past for certain development operations. Acquisition of leases has become more expensive. The permitting process and the subsequent drilling now take longer. While greater certainty is present as we enter 2012 than when we entered 2011, that certainty includes longer permitting times, more rules and regulations and higher costs. See further discussion below under "Risks and Uncertainties."

Total proved reserves as of December 31, 2011 are 118.9 MMBoe. Our proved reserves in the Deepwater Gulf of Mexico account for 62% of our total proved reserves as of December 31, 2011. Our proved reserves on the Gulf of Mexico Outer Continental Shelf account for 2% of our total proved reserves with the remaining 36% in the North Sea. From year-end 2010 to year-end 2011, we increased our proved developed reserve percentage from 18.8% to 23.0%.

Our revenues from oil and natural gas are highly dependent on the underlying commodity prices. During 2011 domestic oil prices hit a high of $113.93 per Bbl and a low of $75.67 per Bbl. Natural gas prices were also volatile, ranging from a high of $4.85 per MMBtu to a low of $2.99 per MMBtu. During 2011 our realized oil price per barrel increased 36% to $98.98 compared to 2010, and natural gas prices decreased 1% to $4.77 per Mcf in the same period. Coupled with the overall 17% increase in production in 2011, our oil and gas revenues rose 64% in 2011. Oil continues to represent the majority of our production accounting for 68% of our volumes on a BOE basis and 88% of our oil and gas revenues.

In 2011, we incurred $436.9 million in capital expenditures. With these expenditures we accomplished the following:

- In February 2011, we began production from MC Block 754, which produces into the Gomez Hub.
- Continued the drilling and completion activities of the third and fourth wells at our Telemark Hub. The third well, the MC 941 A-2, was placed on production in August 2011 and the fourth well, the MC 942 A-3, was placed on production in February 2012;
- Completed and tested two wells at our Clipper property. Both of these wells are scheduled for production in the latter part of 2012 after installation of the pipeline servicing the wells;
- Acquired three deepwater exploration licenses offshore Israel;
- Continued construction of the Octabuoy floating production facility that will serve our Cheviot project in the North Sea;
- Increased total production by 17% to 9.0 MMBoe.

We funded our 2011 activities through a combination of cash provided by operating activities, new equity and debt financings, the sale or conveyance of economic interests in selected properties and financing arrangements with our hedge counterparties and suppliers. During 2011, cash provided by operating activities was $197.1 million. We raised $149.9 million from a preferred stock offering, $59.4 million from a debt financing and $91.0 million from the *Titan* assets – Term Loan Facility. We sold $85.3 million of limited-term overriding royalty interests and net profit interests and had net receipts of $67.1 million from the pre-funding of oil hedges. The details of these transactions are discussed below in *Liquidity and Capital Resources.*

From 2009 to 2011 we financed significant portions of our development program with transactions entered into with our suppliers and their affiliates. We have conveyed to certain suppliers net profits interests in our Telemark Hub, Gomez Hub and Clipper oil and gas properties in exchange for development services. We have also negotiated with certain other vendors involved in the development of the Telemark Hub and Clipper to partially defer payments for a period of twelve months. Development of the Cheviot Hub in the U.K. North Sea continues. We have arranged with the constructor of the floating production facility to defer $228.9 million of payments until 2013. These financial arrangements have preserved our current cash and will allow us to pay vendors from the proceeds of future production. (See Note 7 to our Consolidated Financial Statements for further details.)

2012 Operational Objectives

In the Gulf of Mexico, a primary goal was bringing to production the fourth well at our Telemark Hub. This was accomplished on February 26, 2012. We will continue workover operations on two other wells at the Telemark Hub in an effort to continue to increase production from this location. Later in 2012, we expect to complete a pipeline that will bring to production the two wells at our Clipper project. These two wells were completed and tested during 2011. Workover operations are scheduled at our Gomez Hub and additionally, we are planning to drill of two new Gomez wells starting in late 2012. In the North Sea we are scheduled to begin a development operation at our Blythe location late in 2012. We will continue the construction of our Octabuoy floating production facility with construction completion scheduled in 2013. In Israel we are scheduled to begin drilling our first well during the second quarter of 2012. Additional opportunities in our three core areas plus other opportunities in new areas may be pursued based on available capital, partners and personnel. All of our 2012 development plans in the Gulf of Mexico are dependent upon receiving deepwater drilling, pipeline, completion and other permits from the BOEM. While we believe it is likely that we will receive permits in 2012 allowing us to execute our plans, there is no assurance that the permits will be received in time to impact our 2012 results of operations.

Risks and Uncertainties

Since May 2010 when the federal government imposed the first of a series of moratoriums on drilling in the Gulf of Mexico, we have faced unparalleled difficulties in obtaining permits to continue our development programs. Prior to the moratoriums, we anticipated developing and bringing to production three additional wells at our Telemark Hub and two additional wells at our Gomez Hub by the end of 2010. It has taken until the first quarter of 2012 for us to bring to production all of the three additional wells at the Telemark Hub and, during the third quarter of 2011, the two wells planned for the Gomez Hub were postponed to late 2012/early 2013.

The new wells that have been placed on production have taken longer to complete and bring to production than originally planned and one of them has not produced at rates that were previously projected. In addition, we have incurred capital and operating costs higher than we expected primarily due to additional regulations imposed since the Deepwater Horizon incident and the requirement to perform sidetracks on two of the wells. The new wells helped us achieve production growth in 2011, and we forecast production and operating cash flow growth in 2012 as development activity continues. While cash flows were lower than previously projected due to lower than expected production rates, delays in bringing on new production and higher capital costs, we continued our development operations by supplementing our cash flows from operating activities with funds raised through various transactions (see the Consolidated Statement of Cash Flows.) Our planned operations for 2012 reflect our expectations for production based on actual production history, new production expected to be brought online, the development delays at Telemark and Gomez Hubs discussed above, the deferral of certain capital expenditures, the continuation of commodity prices near current levels, the higher anticipated costs associated with maintaining existing production and bringing new production online, and the higher cost of servicing our additional financing and other obligations.

As of December 31, 2011, we had a working capital deficit of $347.5 million. To preserve our development momentum in the negative working capital environment that we experienced throughout 2011, we have increased our term loans, issued convertible perpetual preferred stock, granted net profits interests (NPI's) to certain of our vendors, sold NPI's and dollar-denominated overriding royalty interests (Overrides) in our properties to investors, and we have entered into prepaid swaps against our future production that provided cash proceeds to us at closing. We have negotiated with the constructor of the hull of the Octabuoy in China to defer the majority of our payments until the hull is ready to be moved to the North Sea, currently scheduled to be during 2013. A similar arrangement is in place for the Octabuoy topside equipment, which is being constructed by the same company in China.

As operator of all of our projects that require cash commitments within the next twelve months and beyond, we retain significant control over the development concept and its timing. We consider the control and flexibility afforded by operating our properties under development to be instrumental to our business plan and strategy. To manage our liquidity, we have delayed certain capital commitments, and within certain constraints, we can continue to conserve capital by further delaying or eliminating future capital commitments. While postponing or eliminating capital projects will delay or reduce future cash flows from scheduled new production, this control and flexibility is one method by which we can match, on a temporary basis, our capital commitments to our available capital resources.

Our cash flow projections are highly dependent upon numerous assumptions including the timing and rates of production from our new wells, the sales prices we realize for our oil and natural gas, the cost to develop and produce our reserves, our ability to monetize our properties and future production through asset sales and financial derivatives, and a number of other factors, some of which are beyond our control. Our inability to increase near-term production levels and generate sufficient liquidity through the actions noted above could result in our inability to meet our obligations as they come due which would have a material adverse affect on us. In the event we do not achieve the projected production and cash flow increases, we will attempt to fund any short-term liquidity needs through other financing sources; however, there is no assurance that we will be able to do so in the future if required to meet any short-term liquidity needs. We believe we can continue to meet our obligations for at least the next twelve months through a combination of cash flow from operations, continuing to sell or assign interests in our properties and selling forward our production through the financial derivatives markets, and if necessary, further delaying certain development activities..

Despite our anticipated production growth, we remain highly leveraged. Servicing our debt and other long-term obligations will continue to place significant constraints on us and makes us vulnerable to adverse economic and industry conditions. Specifically, certain of our financing and derivative transactions require us to make payments in future periods from the proceeds (or net profits) from the sale of production. While these financing transactions have enabled us to continue the development of our properties and meet current operating needs, they will significantly burden the future net cash flows from our production until these obligations are satisfied. (See Note 7, "Other Long-term Obligations," and Note 13, "Derivative Instruments and Risk Management Activities" for further details.)

Our estimates of proved oil and natural gas reserves and the estimated future net revenues from such reserves are based upon various assumptions, including assumptions relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The estimation process requires significant assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise and the quality and reliability of this data can vary. Estimates of our oil and natural gas reserves and the costs and timing associated with developing these reserves are subject to change, and may differ materially from our actual results. A substantial portion of our total proved reserves are undeveloped and recognition of such reserves requires us to expect that capital will be available to fund their development. The size of our operations and our capital expenditures budget limit the number of properties that we can develop in any given year and we intend to continue to develop these reserves, but there is no assurance we will be successful. Development of these reserves may not yield the expected results, or the development may be delayed or the costs may exceed our estimates, any of which may materially affect our financial position, results of operations, cash flows, the quantity of proved reserves that we report, and our ability to meet the requirements of our financing obligations.

A substantial portion of our current production is concentrated among relatively few wells located offshore in the Gulf of Mexico and in the North Sea, which are characterized by production declines more rapid than those of conventional onshore properties. As a result, we are particularly vulnerable to a near-term severe impact resulting from unanticipated complications in the development of, or production from, any single material well or infrastructure installation, including lack of sufficient capital, delays in receiving necessary drilling and operating permits, increased regulation, reduced access to equipment and services, mechanical or operational failures, and bad weather. Any unanticipated significant disruption to, or decline in, our current production levels or prolonged negative changes in commodity prices or operating cost levels could have a materially adverse effect on our financial position, results of operations, cash flows, the quantity of proved reserves that we report, and our ability to meet our commitments as they come due.

Oil and natural gas development and production in the Gulf of Mexico are regulated by the Bureau of Ocean Energy Management ("BOEM") and the Bureau of Safety and Environmental Enforcement ("BSEE") of the Department of the Interior, collectively, formerly known as the Bureau of Ocean Energy Management, Regulation and Enforcement. Our near-term operating and development plans in the Gulf of Mexico, as well as our longer-term business plan, are dependent upon receiving regulatory approvals for deepwater drilling and other permits required by the BSEE. Delays in the permitting process directly impact the timing of our development and production activities, and can materially affect our financial position, results of operations, cash flows, and the quantity of proved reserves that we report.

We cannot predict future changes in laws and regulations governing oil and gas operations in the Gulf of Mexico. New regulations issued since the Deepwater Horizon incident in 2010 have changed the way we conduct our business and increased our costs of developing and commissioning new assets. We incurred additional costs in 2010 from the deepwater drilling moratoriums, subsequent drilling permit delays and additional inspection and commissioning costs. Some of these additional costs continued into 2011 and are projected to continue into 2012. Should there be additional significant future regulations or additional statutory limitations, they could require further changes in the way we conduct our business, further increase our costs of doing business or ultimately prohibit us from drilling for or producing hydrocarbons in the Gulf of Mexico. Additionally, we cannot influence or predict if or how the governments of other countries in which we operate may modify their regulatory regimes from time to time.

As an independent oil and gas producer, our revenue, profitability, cash flows, proved reserves and future rate of growth are substantially dependent on prevailing prices for oil and natural gas. Historically, the energy markets have been very volatile, and we expect such price volatility to continue. Any extended decline in oil or gas prices could have a materially adverse effect on our financial position, results of operations, cash flows, the quantities of oil and gas reserves that we can economically produce, and may restrict our ability to obtain additional financing or to meet the contractual requirements of our debt and other obligations.

Results of Operations

For the years ended December 31, 2011, 2010 and 2009 we reported net loss attributable to common shareholders of $210.5 million, $348.8 million and $51.8 million, or $4.12, $6.88 and $1.24 per diluted share, respectively.

Oil and Gas Production Revenues

Revenues presented in the table and the discussion below represent revenues from sales of oil and natural gas production volumes.

During the second quarter of 2008, we completed the sale of 0.96 MMBoe of proved Gulf of Mexico ("GOM") reserves in the form of a 15% limited-term overriding royalty interest for $82.0 million. In accordance with the accounting standards for extractive activities – oil and gas, the transaction was accounted for as a volumetric production payment. The net proceeds received were recorded as deferred revenue to be recognized in earnings as the production was delivered. The table below includes oil and gas production revenues from amortization of deferred revenue related to this transaction. Because the volumetric production payment represents a conveyance, the reserves were treated as sold in 2008 and the table below does not reflect any production volumes associated with those revenues.

	Year Ended December 31, 2011	2010	2009	% Change from 2010 to 2011	% Change from 2009 to 2010
Production:					
Oil and NGL (MBbls)	6,111	4,471	3,353	37%	33%
Natural gas (MMcf)	17,264	19,151	15,119	(10%)	27%
Total (MBoe)	8,988	7,663	5,873	17%	30%
GOM (MBoe)	8,623	7,114	5,342	21%	33%
North Sea (MBoe)	365	549	531	(34%)	3%
Revenues from production (in thousands):					
Oil and NGL	$ 604,854	$ 326,110	$ 192,044	85%	70%
Amortization of deferred revenue	–	17,819	32,649		
Total	$ 604,854	$ 343,929	$ 224,693	76%	53%
Natural gas	$ 82,354	$ 92,551	$ 64,834	(11%)	43%
Effects of cash flow hedges	–	–	1,719		
Amortization of deferred revenue	–	1,517	7,244		
Total	$ 82,354	$ 94,068	$ 73,797	(12%)	27%
Oil, NGL and natural gas	$ 687,208	$ 418,661	$ 256,878	64%	63%
Effects of cash flow hedges	–	–	1,719		
Amortization of deferred revenue	–	19,336	39,893		
Total	$ 687,208	$ 437,997	$ 298,490	57%	47%
Average realized sales price:					
Oil and NGL – GOM (per Bbl)	$ 98.98	$ 72.94	$ 57.28	36%	27%
Natural gas (per Mcf)	$ 4.77	$ 4.83	$ 4.29	(1%)	13%
Effects of cash flow hedges (per Mcf)	–	–	0.11		
Total (per Mcf)	$ 4.77	$ 4.83	$ 4.40	(1%)	10%
GOM (per Mcf)	4.23	4.53	4.16	(7%)	9%
North Sea (per Mcf)	8.55	6.32	5.34	35%	18%
Oil, NGL and natural gas (per Boe)	$ 76.45	$ 54.66	$ 43.73	40%	25%
Effects of cash flow hedges (per Boe)	–	–	0.30		
Total (per Boe)	$ 76.45	$ 54.66	$ 44.03	40%	24%
GOM (per Boe)	77.50	55.88	45.22	39%	24%
North Sea (per Boe)	51.98	38.54	32.07	35%	20%

Revenues from production increased in 2011 compared to 2010 due to a 40% increase in average realized sales price and a 37% increase in oil production partially offset by a 10% decrease in natural gas production. The oil production increase occurred in the Gulf of Mexico where, by the end of 2011, we had production from three wells at our Telemark Hub. The higher average realized sales price is due to increased commodity market prices.

Revenues from production increased in 2010 compared to 2009 due to a 30% increase in production and a 24% increase in average realized sales price. The production increase occurred primarily in the Gulf of Mexico where, by the end of 2010, we had production from two wells at our Telemark Hub, where we had a workover operation and reversion of an overriding revenue interest at our Gomez Hub and where our Canyon Express property had been returned to production. The higher average realized sales price was due to increased commodity market prices.

Other Revenues

Other revenues for 2009 are comprised of amounts realized under our loss of production income insurance policy due to disruptions caused by Hurricane Ike.

Lease Operating

Lease operating expenses include costs incurred to operate and maintain wells. These costs include, among others, workover expenses, operator fees, processing fees and insurance. Lease operating expense was as follows (in thousands, except per Boe amounts):

	Year Ended December 31,			% Change from 2010 to 2011	% Change from 2009 to 2010
	2011	2010	2009		
Recurring lease operating expenses	$ 92,903	$ 88,437	$ 66,440	5%	33%
Workover expenses	29,299	44,106	18,517	(34%)	138%
Lease operating	122,202	132,544	84,956	(8%)	56%
Recurring operating expenses per Boe	10.34	11.54	11.31	(10%)	2%
Gulf of Mexico	10.15	11.57	11.31	(12%)	2%
North Sea	14.74	11.19	11.34	32%	(1%)

Lease operating expense for 2011 decreased overall by $10.3 million compared to 2010. The increase in recurring lease operating expense was primarily due to the new production from the Telemark Hub. The workover expenses during 2011 were primarily due to hydrate remediation activities, hull repair work and well work at our Telemark Hub and Gomez Hub properties. The workover expenses for 2010 were primarily due to hydrate remediation activities on our Canyon Express pipeline which enabled us to commence production at our Kings Peak well and to re-establish production from two wells at Aconcagua. Per unit costs changed primarily due to the effect of changing production volumes on fixed costs.

Lease operating expense for 2010 increased overall by $47.6 million compared to 2009. The increase in recurring operating expense was primarily due to the new production from the Telemark and Canyon Express Hubs. The workover expenses during 2010 were primarily due to inspection activities on many of our Gulf of Mexico properties and hydrate remediation activities on our Canyon Express and Telemark Hubs, which enabled us to commence production at our new well at Kings Peak and to re-establish production from two wells at Aconcagua. The workover expenses for 2009 included Hurricane Ike repairs and non-routine surveys for properties in the North Sea.

General and Administrative

General and administrative expenses are overhead-related expenses, including employee compensation, legal and accounting fees, insurance, and investor relations expenses. General and administrative expense was as follows:

	Year Ended December 31,			% Change from 2010 to 2011	% Change from 2009 to 2010
	2011	2010	2009		
General and administrative (in thousands)	$ 43,242	$ 43,948	$ 43,469	(2%)	1%
Per Boe	4.81	5.73	7.40	(16%)	(23%)

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization ("DD&A") expense was as follows:

	Year Ended December 31,			% Change from 2010 to 2011	% Change from 2009 to 2010
	2011	2010	2009		
DD&A (in thousands)	$ 298,574	$ 220,657	$ 152,780	35%	44%
Per Boe	33.22	28.80	26.01	15%	11%
Gulf of Mexico	33.17	28.18	24.11	18%	17%
North Sea	34.45	36.79	45.20	(6%)	(19%)

DD&A expense for 2011 increased $77.9 million compared to 2010 primarily due to the increase in production at our Telemark Hub. The per unit increase in the Gulf of Mexico is primarily a result of higher costs incurred on our new developments relative to some of our older properties and the recognition of straight-line depreciation on our *ATP Titan* production platform which was placed into service at the beginning of the second quarter of 2010. The per unit costs for the North Sea decreased primarily due to the effect of production mix differences.

DD&A expense for 2010 increased $67.9 million compared to 2009 primarily due to the commencement of production at Telemark Hub. The per unit increase in the Gulf of Mexico is primarily a result of higher costs incurred on our new developments relative to some of our older properties and the recognition of straight-line depreciation on our *ATP Titan* production platform. The per unit costs for the North Sea decreased primarily due to the effect of production mix differences.

Impairment of Oil and Gas Properties

We recorded impairments during the years ended December 31, 2011, 2010 and 2009 totaling $53.0 million, $42.4 million and $44.6 million, respectively, on certain proved properties in the Gulf of Mexico. We also recorded impairments totaling $1.2 million and $14.9 million during 2011 and 2010, on certain proved properties in the North Sea. The 2011 and 2010 impairments were primarily due to updated performance history. The 2009 impairments were primarily a result of reduced commodity prices and unfavorable operating performance.

Impairments of unproved properties were $3.4 million, $6.0 million and $1.2 million in 2011, 2010 and 2009, respectively, primarily related to surrendered leases in the Gulf of Mexico.

Accretion of Asset Retirement Obligation

Accretion expense in 2011 was $15.0 million compared to $13.8 million in 2010 and $11.7 million in 2009.

Drilling Interruption Costs

Drilling interruption costs represent the costs we have incurred as a result of the deepwater drilling moratoriums and subsequent drilling permit delays caused by the April 2010 Deepwater Horizon incident in the Gulf of Mexico. During 2011, we incurred $19.7 million stand-by costs related to drilling operations at our Telemark and Gomez Hubs. During 2010, a side-track well operation in 7,000 feet of water was interrupted when the moratorium was imposed and work on that project stopped, resulting in the early termination of a drilling contract. In the course of obtaining a full release from our obligations under the contract, we incurred net costs of $8.7 million. Additionally, 2010 drilling interruption costs include $14.9 million of stand-by costs related to drilling operations at our Telemark and Gomez Hubs.

Loss on Abandonment

We recognized aggregate loss on abandonment during 2011, 2010 and 2009 of $3.9 million, $4.8 million and $2.9 million, respectively. These amounts are the result of actual abandonment costs exceeding the previously accrued estimates, due to unforeseen circumstances that required additional work, or the use of equipment more expensive than anticipated and unanticipated vendor price increases.

Gain on Exchange/Disposal of Properties

In December 2011, we sold to a third party our 100% working interest in the deep operating rights of one of our Gulf of Mexico properties resulting in substantially all of the $27.0 million gain on disposal of properties we recognized in 2011.

In 2010, we sold to a third party our 67% working interest in the deep operating rights of one of our Gulf of Mexico properties resulting in a $15.0 million gain. In 2010, we also consummated a nonmonetary exchange of our 10% nonoperated working interest in MC Block 800, for an incremental 50% working interest in MC Block 754, both proved undeveloped properties. The consolidated financial statements reflect the incremental interest acquired in MC Block 754 at fair value and removal of the carrying costs of MC Block 800, resulting in recognition of a $12.0 million gain.

In December 2009, we sold to a third party our 25% working interest in the deep operating rights of one of our Gulf of Mexico properties for $13.0 million in cash, all of which was recognized as a gain.

Interest Income

Interest income varies directly with the amount of temporary cash investments. The decrease in interest income from period to period is the result of a decrease in average cash on hand and a decrease in interest rates.

Interest Expense, Net

Interest expense, net of amounts capitalized is set forth in the following table (in thousands):

	Year Ended December 31,		
	2011	**2010**	**2009**
Interest expense	$ 355,657	$ 275,404	$ 150,984
Capitalized interest:			
ATP Titan – Telemark (Gulf of Mexico)	–	40,400	102,200
Octabuoy – Cheviot (North Sea)	29,246	12,900	7,900
Total capitalized interest	29,246	53,300	110,100
Interest expense, net	$ 326,411	$ 222,104	$ 40,884

The increase in interest expense in 2011 compared to 2010 is primarily due to: (i) an approximate $462 million increase in our aggregate average balance outstanding of debt and other long term obligations in 2011 at a weighted average interest rate of 14.2% in 2011 compared to 13.5% in 2010 (see Note 6, "Long-term Debt" and Note 7, "Other Long-term Obligations" to the Consolidated Financial Statements); (ii) higher noncash interest resulting from the amortization of additional debt-related discounts and issuance costs; and (iii) an increase in interest expense on one of our dollar denominated overrides due to a reduction in the estimated remaining repayment period of the override as a result of greater than forecasted production from the underlying properties at higher than forecasted prices. A reduction in the expected time required to pay the obligation results in an increase in the investor's internal rate of return and requires a corresponding change in the estimated amortization and associated interest expense we record on the obligation. In 2010, our Telemark Hub was placed in service and we therefore ceased capitalizing related interest expense.

The increase in interest expense in 2010 compared to 2009 is primarily due to: (i) an approximate $619 million increase in the aggregate average balance outstanding of debt and other long term obligations in 2010 at a weighted average interest rate of 13.5% in 2010 compared to 10.6% in 2009; and (ii) higher noncash interest resulting from the amortization of additional debt-related discounts and issuance costs.

Derivative Income (Expense)

Derivative income (expense) is primarily related to net gains and losses associated with our oil and gas price derivative contracts and is as follows (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Gulf of Mexico			
Realized gains (losses)	$ (11,215)	$ (1,099)	$ 29,760
Unrealized gains (losses)	34,588	(15,154)	(39,594)
	23,373	(16,253)	(9,834)
North Sea			
Realized gains (losses)	(1,402)	(1,587)	7,801
Unrealized gains (losses)	3,220	(4,579)	1,321
	1,818	(6,166)	9,122
Total			
Realized gains (losses)	(12,617)	(2,686)	37,561
Unrealized gains (losses)	37,808	(19,733)	(38,273)
	$ 25,191	$ (22,419)	$ (712)

Gain (Loss) on Debt Extinguishment

Gain on debt extinguishment of $1.1 million for 2011 was related to an NPI transaction in the Telemark Hub for $40.0 million. The third party purchaser acquired an existing vendor NPI for $19.7 million, thereby extinguishing the existing NPI liability of $20.8 million, and contributed an additional $20.3 million toward the development of the Telemark Hub in exchange for a larger percentage of the net profits from production at the Telemark Hub that will continue until the purchaser recovers $40.0 million, plus an overall rate of return.

Loss on debt extinguishment was $75.3 million in 2010 primarily due to the second quarter refinancing of our previously outstanding term loans in which we charged to expense the remaining unamortized deferred financing costs, debt discount related to the retired debt and repayment premiums.

Income Taxes

During 2011, we recorded a net tax expense of $18.1 million, determined based on the results of operations for the year for each jurisdiction and permanent differences affecting the overall tax rate in each jurisdiction, resulting in an effective tax rate of (12.27%). Included in 2011 foreign operations is the effect of an increase in the UK statutory tax rate from 20% to 30% resulting in a decrease of 8.28% to the effective tax rate benefit on the current year pretax book loss. As of December 31, 2011, for U.S. tax provision purposes, we have a valuation allowance of $155.4 million, which is comprised of a $152.4 million valuation allowance against the net deferred income tax asset position and a $3.0 million valuation allowance related to excess tax benefits from stock options and restricted stock prior to adoption of accounting standards related to stock-based compensation. In addition, as of December 31, 2011 for Netherlands' income tax provision purposes, we have a valuation allowance of $4.9 million, and for Israel income tax provision purposes, we have a valuation allowance of $0.5 million related to the net operating loss carryovers generated in 2011 and in prior periods.

During 2010, we recorded a net tax benefit of $36.3 million, determined based on the results of operations for the year for each jurisdiction and permanent differences affecting the overall tax rate in each jurisdiction, resulting in an effective tax rate of 10.1%. As of December 31, 2011, for U.S. tax provision purposes, we have a valuation allowance of $97.4 million, which is comprised of a $94.4 million valuation allowance against the net deferred income tax asset position and a $3.0 million valuation allowance related to excess tax benefits from stock options and restricted stock prior to adoption of accounting standards related to stock-based compensation. In addition, as of December 31, 2011 for Netherlands' income tax provision purposes, we have a valuation allowance of $1.7 million related to the net operating loss carryovers generated in 2010 and in prior periods.

During 2009, we recorded a net tax benefit of $22.5 million, determined based on the results of operations for the year for each jurisdiction and permanent differences affecting the overall tax rate in each jurisdiction, resulting in an effective tax rate of 38.8%. As of December 31, 2009, for U.S. tax provision purposes, we have a valuation allowance of $3.0 million related to excess tax benefits from stock options and restricted stock prior to adoption of accounting standards related to stock-based compensation. In addition, as of December 31, 2009 for Netherlands' income tax provision purposes, we have a valuation allowance of $1.3 million related to the net operating loss carryover generated in 2009.

Income Attributable to the Redeemable Noncontrolling Interest

Income attributable to the redeemable noncontrolling interest represents the 49% Class A limited partner interest in the earnings of ATP-IP. The amount of $26.6 million in 2011 is an increase from the 2010 $15.5 million amount primarily because in 2011 we entered a period under the agreements when all of the partnership income and cash distributions from the partnership are paid to the Class A limited partner until such time as they have achieved the return of their invested capital plus a specified return. Once those amounts have been received by the Class A limited partner, all cash distributions will be made to ATP, as the owner of the general partner and subordinated limited partner interests until specified amounts have been received. At the conclusion of the special distribution periods, all partners will again share in distributions proportionately according to their ownership in the partnership. The amount of income in 2010 is higher than the 2009 $13.4 million amount primarily because of the inception of this arrangement in the middle of the first quarter of 2009.

Convertible Preferred Stock Dividends

Convertible preferred stock dividends represent declared cash dividends due for outstanding shares which were issued in September 2009 ($140.0 million liquidation value) and June 2011 ($172.5 million liquidation value) which accrue cumulative preferred dividends at the annual rate of 8% of the liquidation value and are payable in either cash or stock at the Company's option.

Liquidity and Capital Resources

Overview

Historically, we have funded our acquisition and development activities through a combination of bank borrowings, proceeds from equity offerings, cash from operations, the sale or conveyance of interests in selected properties, vendor financings, and proceeds of forward sales of our production in the financial derivatives market. Our ongoing cash requirements consist primarily of servicing our debt and other obligations and funding development of our oil and gas reserves. Cash paid for capital expenditures for oil and gas properties was approximately $436.9 million, $598.1 million and $635.4 million for the years ended December 31, 2011, 2010 and 2009, respectively. In 2011, we obtained additional financing from term loans and other sources as discussed below, placed on production another well at our Gomez Hub, placed on production the third well at our Telemark Hub and re-entered and completed drilling the fourth Telemark Hub well, the MC Block 942 A-3 which commenced production on February 26, 2012. This well was originally projected to come on during the fourth quarter of 2011, but was delayed to complete additional sands found and by operational issues that arose during the completion. The delays in production and the additional well costs led to a higher working capital deficit at December 31, 2011 than originally anticipated. We expect with these new wells and workovers we will be performing on existing wells in the first quarter and the two new Clipper wells expected to be placed on production later in the year, we will generate higher operating cash flows in 2012 than in 2011.

We believe we can continue to fund our projected capital expenditures and our existing obligations, including our long-term debt and other long-term obligations, for at least the next twelve months, using projected cash flows from operations, proceeds from the recently announced committed increase in our First Lien term loans, asset monetizations which include the sale of working interests, net profits interests and overriding royalty interests, and if necessary, additional forward sales of our production in the financial derivative markets. In certain cases, we will also continue to work with certain vendors to extend out the timing of certain payments to preserve cash. With certain limitations, we may also delay certain anticipated development expenditures to further preserve cash if necessary. While some of the transactions we have planned for 2012 have been completed or committed, others are still planned to be completed in the future. Our ability to complete those transactions is dependent on a number of factors including our production results, commodity prices and general market conditions; therefore there is no assurance that we will be able to repeat these types of transactions in the future if they are required to meet our short-term liquidity needs. Our longer-term liquidity is also dependent on our production levels and the prevailing prices for oil and natural gas which have historically been very volatile. To mitigate future price volatility, we may continue to hedge the sales price of a portion of our future production.

The size of our operations and our capital expenditures budget limit the number of properties that we can develop in any given year and a substantial portion of our current production is concentrated among relatively few wells located offshore in the Gulf of Mexico and in the North Sea, which are characterized by rapid production declines. As a result, we are particularly vulnerable to a near-term severe impact resulting from unanticipated complications in the development of, or production from, any single material well or infrastructure installation, including lack of sufficient capital, delays in receiving necessary drilling and operating permits, increased regulation, reduced access to equipment and services, mechanical or operational failures, and bad weather. Any unanticipated significant disruption to, or decline in, our current production levels or negative changes in current commodity prices or operating cost levels could have a material adverse effect on our financial position, results of operations and cash flows and our ability to meet our commitments as they come due. We have historically obtained various other sources of funding to supplement our cash flow from operations and we will continue to pursue them in the future, however; there is no assurance that these alternative sources will be available should these risks and uncertainties materialize.

2011 Activities

During February 2011, we entered into Incremental Loan Assumption Agreement and Amendment No. 1, relating to our First Lien Credit Agreement, dated as of June 18, 2010 to, among other things, decrease the interest rate on the entire $149.3 million balance outstanding at the time of the amendment from 11% to 9%. Additional borrowings were $60.0 million ($58.0 million, net of transaction costs and discount).

During March and September 2011, we entered into First and Second Amendments to Term Loan Agreement and Limited Waivers, relating to our Term Loan Facility– *ATP Titan* assets to, among other things, modify the conditions precedent for incremental borrowings drawn under the facility. Additional borrowings were $100.0 million ($89.1 million, net of transactions costs and discount) in the aggregate.

During April, June and December 2011, we conveyed for an aggregate $65.0 million, three dollar-denominated overrides in the Gomez Hub. These overrides obligate us to deliver a percentage of the proceeds from the future sale of hydrocarbons in the specified proved properties until the purchaser achieves a specified return.

Also during April 2011, we closed an NPI transaction in the Telemark Hub for $40.0 million. The purchaser acquired an existing vendor NPI for $19.7 million, thereby extinguishing the existing NPI liability of $20.8 million, and contributed an additional $20.3 million toward the development of the Telemark Hub in exchange for a larger percentage of the net profits from production at the Telemark Hub that will continue until the purchaser recovers an overall specified rate of return.

We have conveyed to certain vendors and financial parties dollar-denominated net profits interests and overriding royalty interests in our Telemark Hub, Gomez Hub and Clipper oil and gas properties in exchange for development services, equipment and cash. We have also negotiated with certain other vendors involved in the development of the Telemark Hub to partially defer payments for periods up to a year. These net profits interests, overriding royalty interests and deferrals allow us to match our development cost cash outflows with proceeds from the sale of production. During 2011, we paid $293.4 million of principal and interest related to our other long-term obligations, which is significantly increased from 2010 due to increased production and higher oil prices. See *Other Long-term Obligations* discussion below.

In June 2011, we issued 1.7 million shares of 8% convertible perpetual preferred stock ("Series B Preferred Stock") and received net proceeds of $123.3 million ($90 per share before underwriters' discounts and commissions, option contract costs (discussed below) and offering expenses). In conjunction with issuance of the Series B Preferred Stock, we purchased for $26.5 million capped-call options ("Options") to cover all 14.1 million shares of common stock issuable upon conversion of the Series B Preferred Stock and the preferred stock we issued in 2009. The Options allow us to prevent dilution due to common stock issuance upon preferred stock conversion up to a price per common share of $27.50. The shares of common stock acquirable under the Options are indexed to our common stock price at the time of exercise and the Options can only be settled in common stock.

The Series B Preferred Stock has terms and features which are substantially identical to the convertible preferred stock we issued in 2009 (collectively, the "Preferred Stock"). Each share of Preferred Stock is perpetual, has no voting rights, has a liquidation preference of $100, pays cumulative dividends at an annual rate of 8% payable in cash, shares of our common stock, or a combination thereof, and is convertible at any time, at the option of the holder, into 4.5045 shares of common stock. After September 30, 2014, we have the option to force conversion to common stock provided that the prevailing common stock market price exceeds the conversion price by 150% on average for a stipulated period of time.

In the second, third and fourth quarters of 2011, we entered into certain off-market oil swap derivative contracts which provided us with $87.9 million cash advances from the counterparty and obligate us to pay market prices at the time of settlement. In the third quarter of 2011, we also terminated certain in-the-money oil swaps and received $10.7 million in proceeds.

2012 Activities

In the U.K. North Sea, development of our interest in the Cheviot field continues. During February 2012, we entered into an amendment to one of our agreements for the construction and delivery of the Octabuoy hull and topside utility module to align the payments with the new expected delivery date of the hull. As amended, the agreements provide for payments of $41.1 million in the first quarter of 2012, and $228.9 million in 2013.

During 2012 through March 9, we sold for $65 million certain limited-term overriding royalty interests in our Gomez Hub. Similar to previous overriding royalty interests sold by us, the purchasers receive a designated portion of the revenues produced at the Gomez Hub until they have obtained the amount of their investment plus a designated return. Once payout of the overriding royalty interests has been achieved, the interests revert back to us. In March 2012, we entered into certain commodity price derivatives contracts which have provided us with net cash advances of $19.4 million and obligate us to pay market prices at the time of settlement.

On March 9, 2012, we entered into Amendment and Restatement and Incremental Loan Assumption Agreement to the Credit Facility ("The Amendment"). The Amendment provides for an increase to the principal amount of the Credit Facility from $210 million to the lesser of $365.0 million or 10% of the Company's Adjusted Consolidated Net Tangible Assets, as defined. The amendment also reduces the interest rate of the Credit Facility from 9% fixed to a floating rate of 8.75% calculated based on a Libor floor of 1.50% plus 7.25%. The other terms of the Credit Facility are essentially unchanged by the Amendment.

By the end of 2012, our plan calls for us to incur $400 million to $500 million in total capital expenditures excluding capitalized interest, of which $50 million to $70 million is expected to be contributed by vendors through existing NPI or deferral programs.

Cash Flows

	Year Ended December 31,		
	2011	2010	2009
Cash provided by (used in) (in thousands):			
Operating activities	$ 197,091	$ (37,280)	$ 159,827
Investing activities	(399,753)	(610,821)	(632,951)
Financing activities	112,049	694,024	358,673

As of December 31, 2011, we had a working capital deficit of approximately $347.5 million, an increase of approximately $241.3 million from December 31, 2010. This deficit is a cumulative result of our capital expenditures exceeding our cash flows from operating and financing activities over the last three years as we have invested heavily in infrastructure and wells that we expect will allow us to increase production and cash flow from operations in future periods. With the increased production we have experienced from capital investment, we expect this working capital deficit to shrink throughout 2012 and into 2013. With our efforts to seek partners for certain of our major capital intensive projects, we also believe this will further decrease our working capital deficit. While a complete elimination of our working capital deficit is our goal, we believe that we should be able to significantly reduce the deficit during the coming year.

Cash provided by (used in) operating activities during 2011 and 2010 was $197.1 million and ($37.3) million, respectively. Cash flow from operating activities has increased primarily due to increased oil and gas revenues related to increased commodity prices and production, partially offset by increased interest and decreases from working capital. Cash provided by (used in) operating activities during 2010 and 2009 was ($37.3) million and $159.8 million, respectively. Cash flow from operating activities decreased primarily due to increased net interest costs, debt extinguishment costs and drilling interruption costs, partially offset by increased oil and gas revenues.

Cash used in investing activities was $399.8 million, $610.8 million and $633.0 million during 2011, 2010 and 2009, respectively. During 2011, cash expended in the Gulf of Mexico and North Sea for additions to oil and gas properties was approximately $234.9 million and $202.0 million, respectively. During 2010, cash expended in the Gulf of Mexico and North Sea for additions to oil and gas properties was approximately $534.3 million and $63.8 million, respectively. During 2009, cash expended in the Gulf of Mexico and North Sea for additions to oil and gas properties was approximately $551.4 million and $83.9 million, respectively.

Cash provided by financing activities was $112.0 million, $694.0 million and $358.7 million during 2011, 2010 and 2009, respectively. The amount in 2011 is primarily related to $235.7 million of proceeds from term loans and other long-term obligations, $123.3 million net proceeds from our Series B preferred stock offering and $67.1 million, net from derivative contracts, partially offset by $206.2 million payments of other long-term liabilities and term loans. Also in 2011, we paid a total of $103.6 million for distributions to the noncontrolling interest, preferred stock dividends and other financings, net. The amount in 2010 is primarily related to $373.8 million net proceeds from the debt refinancing and $228.8 million net proceeds from the *Titan* Assets – Term loan facility, $228.4 million proceeds net of costs from sales of limited-term overriding royalty interests and net profits interests on proved properties, partially offset by principal payments toward our other long-term obligations and outstanding term loans. The amount in 2009 includes proceeds, net of costs, from the sale of a redeemable noncontrolling interest in ATP-IP of $148.8 million, the issuance of common and preferred stock for $306.2 million, net of costs, the monetization of the Gomez hub pipeline for $74.5 million and $14.5 million from sale of an overriding royalty interest. These increases in cash flows were partially offset by $157.5 million of net debt repayments and $19.0 million of distributions to the Class A limited partner in ATP-IP.

Long-term Debt

Long-term debt consisted of the following (in thousands):

	December 31, 2011	December 31, 2010
First lien term loans, net of unamortized discount of $2,460 and $2,644, respectively,	$ 204,703	$ 146,607
Senior second lien notes, net of unamortized discount of $4,671 and $6,071, respectively,	1,495,329	1,493,929
Term loan facility – *ATP Titan* assets, net of unamortized discount of $16,373 and $10,760, respectively,	309,973	238,873
Total debt	2,010,005	1,879,409
Less current maturities	(33,848)	(21,625)
Total long-term debt	$ 1,976,157	$ 1,857,784

Senior Second Lien Notes

In April 2010, we issued senior second lien notes (the "Notes") in an aggregate principal amount of $1.5 billion, due May 1, 2015. The Notes bear interest at an annual rate of 11.875%, payable each May 1 and November 1, and contain restrictions that, among other things, limit the incurrence of additional indebtedness, mergers and consolidations, and certain restricted payments.

At any time (which may be more than once), on or prior to May 1, 2013, the Company may, at its option, redeem up to 35% of the outstanding Notes with money raised in certain equity offerings, at a redemption price of 111.9%, plus accrued interest, if any. In addition, the Company may redeem the Notes, in whole or in part, at any time before May 1, 2013 at a redemption price equal to par plus an applicable make-whole premium plus accrued and unpaid interest to the date of redemption. The Company may also redeem any of the Notes at any time on or after May 1, 2013, in whole or in part, at specified redemption prices, plus accrued and unpaid interest to the date of redemption.

The Notes also contain a provision allowing the holders thereof to require the Company to purchase some or all of those Notes at a purchase price equal to 101% of their aggregate principal amount, plus accrued and unpaid interest to the date of repurchase, upon the occurrence of specified change of control events.

First Lien Term Loans

In June 2010, we entered into a first lien credit agreement (the "Credit Facility") with an initial balance of $150.0 million, due October 15, 2014, to replace the previous credit facility. Initial proceeds of the Credit Facility were $144.3 million, net of original issue discount and transaction fees. Principal outstanding under the term loans issued pursuant to the Credit Facility initially bore interest at an annual rate of 11.0%. The Company granted the lenders a security interest in and a first lien on not less than 80% of its proved oil and gas reserves in the Gulf of Mexico, capital stock of material subsidiaries (limited in the case of the Company's non-U.S. subsidiaries to not more than 65% of the capital stock) and certain infrastructure assets, a portion of which has since been released in connection with the ATP Titan LLC financing discussed below. In February 2011, we entered into Incremental Loan Assumption Agreement and Amendment No. 1, relating to our First Lien Credit Agreement, dated as of June 18, 2010 to, among other things, decrease the interest rate on the entire balance outstanding from 11% to 9%. Additional borrowings were $60.0 million ($58.0 million, net of transaction costs and discount). Quarterly principal payments are required equal to ½% of remaining principal balance until June 18, 2014 and the remaining principal balance is due January 15, 2015.

The Notes and Credit Facility contain certain negative covenants which place limits on the Company's ability to, among other things:

- incur additional indebtedness;
- pay dividends on the Company's capital stock or purchase, repurchase, redeem, defease or retire the Company's capital stock or subordinated indebtedness;
- make investments outside of our normal course of business;
- incur liens;
- create any consensual restriction on the ability of the Company's restricted subsidiaries to pay dividends, make loans or transfer property to the Company;
- engage in transactions with affiliates;
- sell assets; and
- consolidate, merge or transfer assets.

Term Loan Facility - ATP Titan Assets

In September 2010, we formed ATP Titan LLC ("Titan LLC"), a wholly owned and operated subsidiary which we consolidate in our financial statements, and transferred to it our 100% ownership of the *ATP Titan* platform and related infrastructure assets. Simultaneous with the transfer, Titan LLC entered into a $350.0 million term loan facility (the "*ATP Titan* Facility"). Under the initial agreement and the First and Second Amendments to Term Loan Agreement and Limited Waivers entered into in March and September 2011, respectively, we have now drawn down the entire amount available receiving proceeds of $317.9 million, net of discount and direct issuance costs. The *ATP Titan* Facility bears interest at LIBOR (floor of 0.75%) plus 8%. Principal payments are required equal to 2.25% (of original principal) per quarter until October 4, 2012, and 2.5% thereafter until final maturity at September 2017. The *ATP Titan* Facility requires us to maintain in a restricted account a minimum $10.0 million cash balance plus additional amounts based on production at the Telemark Hub to be used for the quarterly debt service of the *ATP Titan* Facility. The *ATP Titan* Facility is collateralized solely by the *ATP Titan* and related infrastructure assets (net book value at December 31, 2011 of $1,105.9 million) and the outstanding member interests in Titan LLC, which are all owned indirectly by the Company. The *ATP Titan* Facility includes a customary condition that there has not occurred a material adverse change with respect to the Company. The Company remains operator and 100% owner of the *ATP Titan* platform, related infrastructure assets and the working interest in its Telemark Hub oil and gas reserves.

The Credit Facility and the Notes contain customary events of default, and if certain of those events of default were to occur and remain uncured, such as a failure to pay principal or interest when due, our lenders could terminate future lending commitments under the Credit Facility, and our lenders could declare the outstanding borrowings due and payable. The Credit Facility also contains an event of default if there has occurred a material adverse change with respect to the Company's compliance with environmental requirements and applicable laws and regulations. The *ATP Titan* Facility contains standard events of default and an event of default if there has occurred a material adverse change with respect to the Company. The *ATP Titan* Facility also contains provisions that provide for cross defaults among the documents entered into in connection with the *ATP Titan* Facility and acceleration of Titan LLC's payment obligations under the *ATP Titan* Facility in certain situations. In addition, our hedging arrangements contain standard events of default, including cross default provisions, that, upon a default, provide for (i) the delivery of additional collateral, (ii) the termination and acceleration of the hedge, (iii) the suspension of the lenders' obligations under the hedging arrangement or (iv) the setoff of payment obligations owed between the parties.

The effective annual interest rate and fair value of our long-term debt was 12.0% and $1.5 billion, respectively, at December 31, 2011. Accrued interest payable was $37.7 million and $34.8 million at December 31, 2011 and 2010, respectively.

Other Long-term Obligations

Other long-term obligations consisted of the following (in thousands):

	December 31, 2011	December 31, 2010
Net profits interests	$ 336,669	$ 331,776
Dollar-denominated overriding royalty interests	42,324	52,825
Gomez pipeline obligation	71,676	73,868
Vendor deferrals – Gulf of Mexico	17,493	7,096
Vendor deferrals – North Sea	94,710	90,874
Other	2,582	2,582
Total	565,454	559,021
Less current maturities	(113,657)	(86,521)
Other long-term obligations	$ 451,797	$ 472,500

Net Profits Interests – Beginning in 2009, we have granted dollar-denominated overriding royalty interests in the form of net profits interests ("NPIs") in certain of our proved oil and gas properties in and around the Telemark Hub, Gomez Hub and Clipper to certain of our vendors in exchange for oil and gas property development services and to certain finance entities in exchange for cash proceeds. During April 2011, we closed an NPI transaction in the Telemark Hub for $40.0 million. The purchaser acquired an existing vendor NPI for $19.7 million, thereby extinguishing the existing NPI liability of $20.8 million, and contributed an additional $20.3 million toward the development of the Telemark Hub in exchange for a larger percentage of the net profits from production at the Telemark Hub that will continue until the purchaser recovers $40.0 million, plus an overall rate of return.

The interests granted are paid solely from the net profits, as defined, of the subject properties. As the net profits increase or decrease, primarily through higher or lower production levels and higher or lower prices of oil and natural gas, the payments due the holders of the net profits interests increase or decrease accordingly. If there is no production from a property or if the net profits are negative during a payment period, no payment would be required. We also accrete the liability over the estimated term in which the NPI is expected to be settled using the effective interest method with related interest expense presented net of amounts capitalized on the Consolidated Statements of Operations. The term of the NPIs is dependent on the value of the services contributed by these vendors or the cash proceeds contributed by the finance companies coupled with the timing of production and future economic conditions, including commodity prices and operating costs. Upon recovery of the agreed rate of return, the NPIs terminate. Because NPIs were granted on proved properties where production is reasonably assured, we have accounted for these NPI's as financing obligations on our Consolidated Balance Sheets. As such, the reserves and production revenues associated with the NPIs are retained by the Company. We expect approximately 60%, or $205 million of the NPIs to be repaid over the next 12 months based on anticipated production, commodity prices and operating costs.

Dollar-denominated Overriding Royalty Interests – During April, June and December 2011, we sold, for an aggregate of $65.0 million, three dollar-denominated overriding royalty interests ("Overrides") in our Gomez Hub properties similar to those sold in 2009 and 2010. These Overrides obligate us to deliver proceeds from the future sale of hydrocarbons in the specified proved properties until the purchasers achieve a specified return. As the proceeds from the sale of hydrocarbons increase or decrease, primarily through changes in production levels and oil and natural gas prices, the payments due the holders of the overriding royalty interests will increase or decrease accordingly. If there is no production from a property during a payment period, no payment would be required. The percentage of property revenues available to satisfy these obligations is dependent upon certain conditions specified in the agreement. Upon recovery of the agreed rate of return, the Overrides terminate and our interest increases accordingly. Because of the explicit rate of return, dollar-denomination and limited payment terms of the Overrides, they are reflected in the accompanying financial statements as financing obligations. As such, the reserves and production revenues are retained by the Company. Related interest expense is presented net of amounts capitalized on the Consolidated Statements of Operations. As of December 31, 2011, if there is sufficient production from a certain property, we will incur up to $7.2 million of contingent interest costs. We expect approximately 93%, or $39 million of the Overrides to be repaid over the next 12 months based on anticipated production and commodity prices.

Gomez Pipeline Obligation – In 2009, we sold to a third party for net proceeds of $74.5 million the oil and natural gas pipelines that service the Gomez Hub. In conjunction with the sale, we entered into agreements with the purchaser to transport our oil and natural gas production for the remaining production life of our fields serviced by the *ATP Innovator* production platform for a per-unit fee that is subject to a minimum monthly payment through December 31, 2016. Such minimum fees, if applicable, can be recovered by ATP in future periods within the same calendar year whenever fees owed during a month exceed the minimum due. We remain the operator of the pipeline and are responsible for all of the related operating costs. As a result of the retained asset retirement obligation and the purchaser's option to convey the pipeline back to us at the end of the life of the fields in the Gomez Hub, the transaction has been accounted for as a financing obligation equal to the net proceeds received. This obligation is being amortized based on the estimated proved reserve life of the Gomez Hub properties using the effective interest method with related interest expense presented net of amounts capitalized on the Consolidated Statements of Operations. All payments made in excess of the minimum fee in future periods will be reflected as interest expense of the financing obligation.

Vendor Deferrals – In the Gulf of Mexico, in addition to the NPIs exchanged for development services described above, we have negotiated with certain other vendors involved in the development of the Telemark and Gomez Hubs to partially defer payments over a twelve-month period beginning with first production. We accrue the present value of the deferred payments and accrete the balance over the estimated term in which it is expected to be paid using the effective interest method with related interest expense presented net of amounts capitalized, on the Consolidated Statements of Operations.

In the U.K. North Sea, development of our interest in the Cheviot field continues. During February 2012, we entered into an amendment to one of our agreements for the construction and delivery of the Octabuoy hull and topside utility module to align the payments with the new expected delivery date of th hull. As amended, the agreements provide for a $41.1 million payment in the first quarter of 2012, and $228.9 million in 2013. As work is completed and amounts are earned under the amended agreement, we record obligations and related interest expense, net of amounts capitalized, on the Consolidated Financial Statements.

Effective Interest Rate – The weighted average effective interest rate on our other long-term obligations set forth above was 18.9% and 16.7% at December 31, 2011 and 2010, respectively.

Recently Issued Accounting Pronouncements

See Note 2, "Summary of Significant Accounting Policies - Recently Issued Accounting Pronouncements" to the Consolidated Financial Statements.

Contractual Obligations

The following table summarizes certain contractual obligations at December 31, 2011 (in thousands):

	Total	Less than 1 year	1 – 3 years	3 – 5 years	More than 5 years
First lien term loans	$ 207,163	$ 2,066	$ 4,071	$ 201,026	$ –
Interest on first lien term loans (1)	56,741	18,901	37,136	704	–
Senior second lien notes	1,500,000	–	–	1,500,000	–
Interest on senior second lien notes (1)	593,750	178,125	356,250	59,375	–
Term loan facility – *ATP Titan* assets	326,345	31,782	70,000	70,000	154,563
Interest on term loan facility – *ATP Titan* assets (1)	112,935	26,860	44,748	32,484	8,843
Asset retirement obligations	168,517	52,536	31,623	2,434	81,924
Other long-term obligations (2)	346,189	75,108	250,248	20,000	833
Other trade commitments	3,647	–	3,647	–	–
Noncancelable operating leases	1,871	1,181	690	–	–
Total contractual obligations	$ 3,317,158	$ 386,559	$ 798,413	$ 1,886,023	$ 246,163

(1) Interest is based on rates and principal repayment requirements in effect at December 31, 2011.
(2) Of these amounts, $183.9 million are accrued at December 31, 2011.

Excluded from the table above are the following:

- NPIs and Overrides of $336.7 million and $42.3 million, respectively, as of December 31, 2011 that are payable only from the future cash flows of specified properties. The ultimate amount and timing of the payments will depend on production from the properties and future commodity prices and operating costs. We expect approximately 64% or $244 million of the NPIs and Overrides to be repaid over the next 12 months based on projected production, commodity prices and operating costs.
- Dividends on our 8% convertible perpetual preferred stock, which are approximately $25.0 million per year. These dividends are payable in cash or stock at the Company's option, although covenants with our creditors may prevent us from paying cash in the future.
- ATPIP is currently obligated to distribute effectively all of its cash earnings to the noncontrolling interest until the total remaining balance of $115.8 million has been paid. The ultimate amount and timing of the payments will depend on the oil and gas volumes which flow across the *ATP Innovator* production platform. We expect approximately $31.0 million or 27% of the $115.8 million noncontrolling interest to be repaid over the next 12 months.
- Obligations under commodity derivative contracts, which at December 31,2011 represent an aggregate net liability of $66.6 million related to 2012 and $0.5 million related to 2013, based on year-end market prices. See additional discussion of commodity derivative contracts in Note 13, Derivative Instruments and Price Risk Management Activities.
- Contingent interest on certain Overrides which may total $7.2 million, the ultimate amount and timing of which will depend on production from the properties and future commodity prices.
- Contingent consideration of $7.8 million to be paid by us upon achieving specified operational milestones because the ultimate amount and timing of the payments will depend on production from the specified properties and future commodity prices.
- We are a party to a multi-year (life of reserves) firm transportation agreement covering certain production in the North Sea that requires us to pay a pipeline tariff on our nominated contract quantity of natural gas during the contract period, whether or not the volumes are delivered to the pipeline. For any contract period where actual deliveries fall short of contract quantities, we can make up such amounts by delivering volumes over the subsequent four years free of tariff, within certain limitations. While we control our nominations, we are subject to the risk we may be required to prepay or ultimately pay transportation on undelivered volumes. The ultimate amount and timing of any payments is uncertain and dependent upon our production levels. At current production levels, the minimum annual obligation under these agreements is approximately £0.6 million per year, or approximately $1.0 million at December 31, 2011.

Critical Accounting Policies and Estimates

Our consolidated financial statements are prepared in conformity with U.S. generally accepted accounting principles ("GAAP"), which require management to make estimates and assumptions that affect the reported amounts of the assets and liabilities and disclosures of contingent assets and liabilities as of the date of the balance sheet as well as the reported amounts of revenues and expenses during the reporting period. We routinely make estimates and judgments about the carrying value of our assets and liabilities that are not readily apparent from other sources. Such estimates and judgments are evaluated and modified as necessary on an ongoing basis. Significant estimates include DD&A and impairment of oil and gas properties. Oil and gas reserve estimates, which are the basis for unit-of-production DD&A and the impairment analysis, are inherently imprecise and are expected to change as future information becomes available. In addition, alternatives may exist among various accounting methods. In such cases, the choice of accounting method may also have a significant impact on reported amounts.

Based on a critical assessment of our accounting policies discussed below and the underlying judgments and uncertainties affecting the application of those policies, management believes that our consolidated financial statements provide a meaningful and fair representation of our company.

Oil and Gas Property Accounting

We account for our oil and gas property costs using the successful efforts accounting method. Under the successful efforts method, lease acquisition costs and intangible drilling and development costs on successful wells and development dry holes are capitalized. Costs of drilling exploratory wells are initially capitalized, but charged to expense if and when a well is determined to be unsuccessful.

Capitalized proved property acquisition costs are depleted on the unit-of-production method on the basis of total estimated units of proved reserves. Capitalized costs relating to producing properties are depleted on the unit-of-production method on the basis of total estimated units of proved developed reserves. When significant development costs (such as the cost of an offshore production platform) are incurred in connection with a planned group of development wells before all of the planned wells have been drilled, it is occasionally necessary to exclude a portion of those development costs in determining the unit-of-production depletion rate until the additional development wells are drilled. However, in no case are future development costs anticipated in computing our depletion rate. Estimated dismantlement, restoration and abandonment costs and estimated residual salvage values are taken into account in determining depletion provisions. Our *ATP Titan* and *ATP Innovator* floating platforms are included in oil and gas properties and depreciated straight line over 40 and 25 years, respectively, since they can be relocated to other fields when existing production is depleted. Expenditures for geological and geophysical testing costs are generally charged to expense unless the costs can be specifically attributed to mapping a proved reservoir and determining the optimal placement for future developmental well locations. Expenditures for repairs and maintenance are charged to expense as incurred; renewals and betterments are capitalized. The costs and related accumulated depreciation, depletion, and amortization of properties sold or otherwise retired are eliminated from the accounts, and gains or losses on disposition are reflected in the statements of operations.

We perform impairment analysis whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management's estimates of future oil and gas prices to the estimated future production of oil and gas reserves over the economic life of the property and deducting future costs. Future net cash flows are based upon reservoir engineers' estimates of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions and actual or planned drilling or other development activities. For a property determined to be impaired, an impairment loss equal to the difference between the carrying value and the estimated fair value of the impaired property will be recognized. Fair value, on a depletable unit basis, is estimated to be the present value of the aforementioned expected future net cash flows. Unproved properties are assessed periodically to determine whether they have been impaired. An impairment allowance is provided on an unproved property when we determine that the property will not be developed, but no later than lease expiration. Any impairment charge incurred is recorded in accumulated depletion, depreciation, impairment and amortization to reduce our basis in the asset. Each part of these calculations is subject to a large degree of judgment, including estimated reserves, future net cash flows and fair value.

Oil and Gas Reserves

The process of estimating quantities of natural gas and crude oil reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in the financial statement disclosures. We use the unit-of-production method to amortize our oil and gas properties. This method requires us to amortize the capitalized costs incurred in developing a property in proportion to the amount of oil and gas produced as a percentage of the amount of proved reserves contained in the property. Accordingly, changes in reserve estimates as described above will cause corresponding changes in DD&A recognized in periods subsequent to the reserve estimate revision. In all years presented, 100% of our reserves were prepared by independent petroleum engineers. Currently, we use Collarini Associates and Ryder Scott Company, L.P. See the Supplemental Information (unaudited) in our consolidated financial statements for reserve data related to our properties.

Asset Retirement Obligations

We recognize liabilities associated with the eventual retirement of tangible long-lived assets, upon the acquisition, construction and development of the assets. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Changes in estimates on fully depleted properties are charged directly to loss on abandonment.

Shortages or an increase in cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our abandonment operations, which could have a material adverse effect on our business, financial condition and results of operations. Increased drilling activity in the Gulf of Mexico and the North Sea decreases the availability of offshore rigs and associated equipment. In periods of increased drilling activity in the Gulf of Mexico and the North Sea, we may experience increases in associated costs, including those related to drilling rigs, equipment, supplies and personnel and the services and products of other vendors to the industry. These costs may increase further and necessary equipment and services may not be available to us at economical prices.

We recognize (i) depletion expense on the additional capitalized asset retirement costs; (ii) accretion expense as the present value of the future asset retirement obligation increases with the passage of time, and; (iii) the impact, if any, of changes in estimates of the liability.

Other Long-term Obligations

We have significant obligations primarily related to placing the *ATP Titan* in service and completing and commencing production from the underlying Telemark Hub oil and gas wells. A significant portion of these obligations will be paid from limited-term overriding royalty interests and net profits interests in the underlying reserves we have granted or sold, or under vendor payment deferral arrangements. We also have significant vendor deferral obligations related to constructing the Octabuoy hull and related topside equipment planned for initial deployment at our Cheviot field in the U.K. North Sea. The recorded liabilities for these obligations are affected by some significant estimates, including the ultimate cost of the obligations, the ultimate reserves produced and the timing of production, which dictates the timing of the future cash payments. Such estimated amounts are discounted so that they are reflected on the consolidated balance sheet at present value. Revisions to these estimates may be required which will result in upward or downward revisions in the recorded long-term obligations and associated interest expense on a prospective basis.

Price Risk-Management Activities

We utilize derivative instruments and fixed-price forward sales contracts with respect to a portion of our expected production in order to manage our exposure to oil and natural gas price volatility. These instruments expose us to risk of financial loss if:

- production is less than expected for forward sales contracts;

- the counterparty to the derivative instrument defaults on its contract obligations; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and the actual prices received for our production at the physical sales point.

Our results of operations may be negatively impacted in the future by our derivative instruments and fixed-price forward sales contracts as these instruments may limit any benefit we would otherwise receive from increases in the prices for oil and natural gas.

We primarily utilize fixed-price physical forward contracts, price swaps, price collars and put options which are generally placed with major financial institutions or with counterparties of high credit quality in order to minimize our credit risks. The oil and natural gas reference prices of these commodity derivative contracts are based upon oil and natural gas market exchanges which have a high degree of historical correlation with the actual prices we receive. All derivative instruments are recorded on the balance sheet at fair value with changes in fair value recorded as a component of derivative income (expense) in our consolidated statement of operations. Occasionally, we sell certain natural gas call options in exchange for premiums from the counterparties. At settlement of a call option, if the market price exceeds the strike price of the call option, the Company pays the counterparty such excess. If the market price settles below the strike price of the call option, no payment is due from either party. Cash settlements of our derivative instruments are classified as operating cash flows unless the derivative contains a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying Consolidated Statements of Cash Flows.

From time to time, we utilize foreign currency and interest rate derivative instruments to mitigate risks associated with our foreign operations and borrowings, respectively.

Valuation of Deferred Tax Asset

We compute income taxes using an asset and liability approach, which results in the recognition of deferred tax liabilities and assets for the expected future tax consequences of temporary differences between the carrying amounts and the tax basis of those assets and liabilities. We also record a valuation allowance if it is more likely than not that some or all of a deferred tax asset will not be realized. In determining whether a valuation allowance is appropriate, we weigh positive and negative evidence that suggests whether a deferred tax asset is likely to be recoverable. As of December 31, 2011, for U.S. tax provision purposes, we have provided valuation allowance for the remainder of our net deferred tax assets based on our cumulative net losses coupled with the uncertainties surrounding the future profitability of our.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements at December 31, 2011.

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

Commodity Price Risk

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. We currently sell a portion of our oil and natural gas production under market price contracts. We periodically use derivative instruments to hedge our commodity price risk. We hedge a portion of our projected oil and natural gas production through a variety of financial and physical arrangements intended to support oil and natural gas prices at targeted levels and to manage our exposure to price fluctuations. We may use futures contracts, swaps, prepaid swaps, put options, price collars, call options and fixed-price physical forward contracts to hedge our commodity prices. See Note 13, "Derivative Instruments and Risk Management Activities" to Consolidated Financial Statements. We do not hold or issue derivative instruments for speculative purposes.

At February 29, 2012, we had derivative contracts in place for the following oil and natural gas volumes.

Period	Type	Volumes	Price $/Unit
Oil (Bbl) – *Gulf of Mexico*			
2012	Swaps	3,408,250	100.68
2013	Swaps	455,000	103.04
2012	Prepay Swaps (1)	476,950	–
2012	Basis Swaps	825,000	12.34
2013	Basis Swaps	820,000	4.60
2013	Swaption (2)	1.095,000	96.88
Natural Gas (MMBtu)			
North Sea			
2012	Swaps	1,830,000	9.03
2013	Swaps	180,000	11.28
Gulf of Mexico			
2012	Fixed-price physicals	1,365,000	4.64
2012	Calls (3)	3,660,000	5.35

(1) In order to manage our exposure to oil price volatility and to provide additional current liquidity, in the second half of 2011, we entered into certain off-market oil swap derivative contracts which provided us with $87.9 million of cash advances from the counterparty and obligate us to pay market prices at the time of settlement.

(2) In 2012, we entered into certain derivative contracts which give the counterparty the right, for a period of time, to bind us in agreed-upon oil price swap contracts in exchange for a premium paid to us. Should the counterparty elect not to bind us to the swap contract, the option to do so terminates and there is no further financial exposure to either party.

(3) We sold certain natural gas call options in exchange for a premium from the counterparties. At settlement of a call option, if the market price exceeds the strike price of the call option, the Company pays the counterparty such excess. If the market price settles below the strike price of the call option, no payment is due from either party.

Interest Rate Risk

We are exposed to changes in interest rates only on our *ATP Titan* assets - Term Loan Facility as described in Management's Discussion and Analysis of Financial Condition and Results of Operations: Liquidity and Capital Resources. Each 1% change in LIBOR above the floor rate of 0.75% equates to approximately $3.3 million of additional interest expense on these obligations. Otherwise we have no exposure to changes in interest rates because the interest rates on our other long-term debt instruments are fixed.

Foreign Currency Risk

The net assets, net earnings and cash flows from our wholly owned subsidiaries in the U.K. and the Netherlands are based on the U.S. dollar equivalent of such amounts measured in the applicable functional currency. These foreign operations have the potential to impact our financial position due to fluctuations in the value of the local currency arising from the process of re-measuring the local functional currency in U.S. dollars.

Item 8. *Financial Statements and Supplementary Data.*

The information required here is included in the report as set forth in the "Index to the Consolidated Financial Statements" on page F-1.

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

None.

Item 9A. Controls and Procedures.

Disclosure Controls and Procedures

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Our management, under the supervision of and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of ATP Oil & Gas Corporation's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities and Exchange Act of 1934, as amended (the "Exchange Act") as of December 31, 2011 (the "Evaluation Date"). Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of the Evaluation Date to ensure that the information required to be disclosed in our Exchange Act filings is (1) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission's rules and forms, and (2) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

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Management's Report on Internal Control over Financial Reporting

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Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Exchange Act).

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework.* Based on this assessment, management concluded that our internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited and reported on the financial statements included in this annual report, as stated in their reports which are included herein.

Changes in Internal Control Over Financial Reporting

There were no changes in internal control over financial reporting during the quarter ended December 31, 2011 that materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

Item 9B. *Other Information.*

None.

PART III

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

Executive Officers of the Company and Other Key Employees

Set forth below are the names, ages (as of February 28, 2012) and titles of the persons currently serving as executive officers of the Company. There are no term limits for the executive officers.

Name	Age	Position
T. Paul Bulmahn	68	Chairman and Chief Executive Officer
Leland E. Tate	64	President
Albert L. Reese Jr.	62	Chief Financial Officer
George R. Morris	57	Chief Operating Officer
John E. Tschirhart	61	Senior Vice President, International, General Counsel
Isabel M. Plume	51	Chief Communications Officer
Keith R. Godwin	44	Chief Accounting Officer

T. Paul Bulmahn has served as our Chairman and Chief Executive Officer since May 2008 and before that as Chairman and President since he founded the company in 1991. From 1988 to 1991, Mr. Bulmahn served as President and Director of Harbert Oil & Gas Corporation. From 1984 to 1988, Mr. Bulmahn served as Vice President, General Counsel of Plumb Oil Company. From 1978 to 1984, Mr. Bulmahn served as counsel for Tenneco's interstate gas pipelines and as regulatory counsel in Washington, D.C. From 1973 to 1978, he served the Railroad Commission of Texas, the Public Utility Commission and the Interstate Commerce Commission as an administrative law judge.

Leland E. Tate has served as our President since May 2008, before that as Chief Operating Officer since December 2003 and Sr. Vice President, Operations since August 2000. Prior to joining us, Mr. Tate worked for over 30 years with Atlantic Richfield Company ("ARCO"). From 1998 until July 2000, Mr. Tate served as the President of ARCO North Africa. He also was Director General of Joint Ventures at ARCO from 1996 to 1998. From 1994 to 1996, Mr. Tate served as ARCO's Vice President Operations & Engineering, where he led technical negotiations in field development. Prior to 1994, Mr. Tate's positions with ARCO included Director of Operations, ARCO British Ltd.; Vice President of Engineering, ARCO International; Senior Vice President Marketing and Operations, ARCO Indonesia; and for three years was Vice President and District Manager in Lafayette, Louisiana.

Albert L. Reese Jr. has served as our Chief Financial Officer since March 1999 and, in a consulting capacity, as our director of finance from 1991 until March 1999. From 1986 to 1991, Mr. Reese was employed with the Harbert Corporation where he established a registered investment bank for the company to conduct project and corporate financings for energy, co-generation, and small power activities. From 1979 to 1986, Mr. Reese served as chief financial officer of Plumb Oil Company and its successor, Harbert Energy Corporation. Prior to 1979, Mr. Reese served in various capacities with Capital Bank in Houston, the independent accounting firm of Peat, Marwick & Mitchell, and as a partner in Arnold, Reese & Swenson, a Houston-based accounting firm specializing in energy clients.

George R. Morris has served as our Chief Operating Officer since May 2008. He served as our Vice President, Acquisitions from 2002 until 2004 and upon his return to the company in 2007. From 2004 until 2007, Mr. Morris was Chief Operating Officer at Chroma Exploration & Production. Prior to joining us in 2002 and during a career that spanned 30 years, Mr. Morris held executive and management positions in operations and engineering at Burlington Resources, Louisiana Land and Exploration, Nerco Oil & Gas and Union Texas Petroleum. Mr. Morris is a registered professional engineer in the State of Texas and has a B.S. in mechanical engineering from Colorado State University.

John E. Tschirhart joined us in November 1997 and has served as our General Counsel since March 1998 and Assistant Corporate Secretary since 2007. Mr. Tschirhart was named Senior Vice President International in July 2001 and served as Managing Director of ATP Oil & Gas (UK) Limited from May 2000 to May 2001. He has served on the board of directors of ATP Oil & Gas (UK) Limited and ATP Oil & Gas (Netherlands) B.V. since the formation of those corporations and currently serves as the Managing Director of ATP Oil & Gas (Netherlands) B.V. From 1993 to November 1997, Mr. Tschirhart worked as a partner at the law firm of Tschirhart and Daines, a partnership in Houston, Texas. From 1985 to 1993 Mr. Tschirhart was in private practice handling civil litigation matters including oil and gas and employment law. From 1979 to 1985, he was with Coastal Oil & Gas Corporation and from 1974 to 1979 he was with Shell Oil Company.

Isabel M. Plume has served as our Chief Communications Officer since 2004 and Corporate Secretary since 2003. Ms. Plume currently serves on the board of directors of ATP Oil & Gas (UK) Limited and ATP Oil and Gas (Netherlands) B.V. From 1996 to 1998, she was employed by Oasis Pipe Line Company, a midstream transporter of natural gas, responsible for implementing accounting and reporting systems. From 1982 to 1995 Ms. Plume served in a financial reporting capacity for Dow Hydrocarbons & Resources, Inc. and the Dow Chemical Company.

Keith R. Godwin has served as our Chief Accounting Officer since April 2004. He served as Controller and Vice President from August 2000 to March 2004 and Controller from 1997 to July 2000. From 1995 to 1997, Mr. Godwin was the Corporate Accounting Manager with Champion Healthcare Corporation. From 1990 to 1995, Mr. Godwin was employed as an accountant with Coopers & Lybrand L.L.P. where he conducted audits primarily in the energy industry.

Except for the information relating to Executive Officers of the Registrant set forth above, the information required by Item 10 of Form 10-K is incorporated herein by reference to the definitive proxy statement for the Company's Annual Meeting of Shareholders to be held during June 2012 (the "Proxy Statement.")

We have adopted a Code of Business Conduct and Ethics that applies to all of our employees, officers and directors, including our principal executive officer, principal financial officer, principal accounting officer and controller, and it is available on our internet website at www.atpog.com. In the event that an amendment to, or a waiver from, a provision of our Code of Business Conduct and Ethics that applies to any of the executive officers (including the principal executive officer, principal financial officer, principal accounting officer and controller) or directors is necessary, we intend to post such information on our website.

Item 11. ***Executive Compensation.***

Incorporated by reference to the Company's Proxy Statement.

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

Incorporated by reference to the Company's Proxy Statement.

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

Incorporated by reference to the Company's Proxy Statement.

Item 14. ***Principal Accounting Fees and Services.***

Incorporated by reference to the Company's Proxy Statement.

PART IV

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

(a) (1) and (2) Financial Statements and Financial Statement Schedules

See "Index to Consolidated Financial Statements" on page F-1.

(a) (3) Exhibits

3.1	Amended and Restated Certificate of Formation, incorporated by reference to Exhibit 3.1 of the Current Report on Form 8-K of ATP Oil & Gas Corporation ("ATP") filed June 10, 2010.
3.2	Statement of Resolutions Establishing the 8.00% Convertible Perpetual Preferred Stock of ATP Oil & Gas Corporation, incorporated by reference to Exhibit 4.4 of Registration Statement No. 333-162574 on Form S-3 of ATP filed October 19, 2009.
3.3	Statement of Resolutions Establishing the 8.00% Convertible Perpetual Preferred Stock, Series B of ATP Oil & Gas Corporation, incorporated by reference to Exhibit 3.1 of ATP's Current Report on Form 8-K filed June 21, 2011.
3.4	Third Amended and Restated Bylaws of ATP Oil & Gas Corporation, incorporated by reference to Exhibit 3.1 of ATP's Current Report on Form 8-K filed December 15, 2009.
4.1	Rights Agreement dated October 11, 2005 between ATP and American Stock Transfer & Trust Company, as Rights Agent, specifying the terms of the Rights, which includes the form of Statement of Designations of Junior Participating Preferred Stock as Exhibit A, the form of Right Certificate as Exhibit B and the form of the Summary of Rights to Purchase Preferred Shares as Exhibit C, incorporated by reference to Exhibit 1 to the Company's Registration Statement on Form 8-A filed with the Securities and Exchange Commission on October 14, 2005.
4.2	Form of Stock Certificate for 8.00% Convertible Perpetual Preferred Stock, incorporated by reference to Exhibit 4.1 of ATP's Form 8-K dated September 29, 2009.
4.3	Form of Stock Certificate for 8.00% Convertible Perpetual Preferred Stock, Series B, incorporated by reference to Exhibit 4.1 of ATP's Current Report on Form 8-K filed June 21, 2011.
4.4	Indenture dated as of April 23, 2010 between the Company and The Bank of New York Mellon Trust Company, N.A., as trustee ("Trustee"), incorporated by reference to Exhibit 4.1 to ATP's Current Report on Form 8-K dated April 29, 2010.
4.5	Registration Rights Agreement dated as of April 23, 2010 between the Company and J.P. Morgan Securities Inc., incorporated by reference to Exhibit 10.2 to ATP's Current Report on Form 8-K dated April 29, 2010.
4.6	Form of Nonqualified Stock Option Agreement, incorporated by reference to Exhibit 4.6 of Registration Statement No. 333-171263 on Form S-8 of ATP filed December 17, 2010.
4.7	Form of Restricted Stock Award Agreement (to be used in connection with awards to directors of ATP), incorporated by reference to Exhibit 4.7 of Registration Statement No. 333-171263 on Form S-8 of ATP filed December 17, 2010.
4.8	Form of Restricted Stock Award Agreement (to be used in connection with awards to executive officers of ATP), incorporated by reference to Exhibit 4.8 of Registration Statement No. 333-171263 on Form S-8 of ATP filed December 17, 2010.
10.1	Credit Agreement dated as of June 18, 2010 among ATP Oil & Gas Corporation, Credit Suisse AG and the lenders party thereto, incorporated by reference to Exhibit 10.1 of ATP's Current Report on Form 8-K dated June 18, 2010.
10.2	Term Loan Agreement, dated as of September 24, 2010 among Titan LLC, as the Borrower, CLMG Corp., as Agent, and the Lenders party thereto incorporated by reference to Exhibit 99.1 to ATP's Current Report on Form 8-K dated September 24, 2010.
10.3	ATP Oil & Gas Corporation 2010 Stock Plan incorporated by reference to Appendix A to ATP's Schedule 14A dated April 29, 2010.

10.4	Intercreditor Agreement dated as of April 23, 2010 among the Company, the Trustee and Credit Suisse AG, incorporated by reference to Exhibit 10.3 to ATP's Current Report on Form 8-K dated April 29, 2010.
10.5	Sale and Purchase Agreement between ATP Oil & Gas (UK) Limited and EDF Production UK Ltd., as amended and restated on October 23, 2008, incorporated by reference to Exhibit 10.1 to ATP's Report on Form 10-Q for the quarter ended September 30, 2008.
10.6	Employment Agreement between ATP and Leland E. Tate, dated December 30, 2010, incorporated by reference to Exhibit 10.5 to ATP's Form 8-K dated December 30, 2010.
10.7	Employment Agreement between ATP and Albert L. Reese, Jr., dated December 30, 2010, incorporated by reference to Exhibit 10.4 to ATP's Form 8-K dated December 30, 2010.
10.8	Employment Agreement between ATP and Keith R. Godwin, dated December 30, 2010, incorporated by reference to Exhibit 10.2 to ATP's Form 8-K dated December 30, 2010.
10.9	Employment Agreement between ATP and T. Paul Bulmahn, dated December 30, 2010, incorporated by reference to Exhibit 10.1 to ATP's Form 8-K dated December 30, 2010.
10.10	Employment Agreement between ATP and George R. Morris, dated December 30, 2010, incorporated by reference to Exhibit 10.3 to ATP's Form 8-K dated December 30, 2010.
10.11	All Employee Bonus Policy, incorporated by reference to exhibit 10.16 to ATP's Annual Report on Form 10-K for the year ended December 31, 2008.
10.12	Discretionary Bonus Policy, incorporated by reference to exhibit 10.17 to ATP's Annual Report on Form 10-K for the year ended December 31, 2008.
10.13	Incremental Loan Assumption Agreement and Amendment No. 1 to Credit Agreement among ATP, the lenders party thereto and Credit Suisse AG, incorporated by reference to Exhibit 10.1 of ATP's Form 8-K dated February 19, 2011.
10.14	Amendment and Restatement and Incremental Loan Assumption Agreement dated as of March 9, 2012 to Credit Agreement dated as of June 18, 2010, as amended, among ATP, Credit Suisse AG and the lenders party thereto, incorporated by reference to Exhibit 10.1 of ATP's Form 8-K dated March 9, 2012.
10.15	Amended and restated letter agreement dated June 15, 2011 between the Company and Credit Suisse International, c/o Credit Suisse Securities USA LLC relating to the capped call transactions, incorporated by reference to Exhibit 10.1 of ATP's Current Report on Form 8-K filed June 21, 2011.
21.1	Subsidiaries of ATP, incorporated by reference to Exhibit 21.1 to ATP's Report on Form 10-Q for the quarter ended March 31, 2011.
*23.1	Consent of PricewaterhouseCoopers LLP.
*23.2	Consent of Collarini Associates.
*23.3	Consent of Ryder Scott Company, L.P.
*23.4	Management report of third party engineers – Collarini Associates
*23.5	Management report of third party engineers – Ryder Scott Company, L.P. – Gulf of Mexico
*31.1	Certification of Principal Executive Officer pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934, the "Act"
*31.2	Certification of Principal Financial Officer pursuant to Rule 13a-14(a) of the Act
*32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350
*32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350
+101	Interactive Data File

* Filed herewith
+ IN ACCORDANCE WITH THE TEMPORARY HARDSHIP EXEMPTION PROVIDED BY RULE 201 OF REGULATION S-T, THE DATE BY WHICH THE INTERACTIVE DATA FILE IS REQUIRED TO BE SUBMITTED HAS BEEN EXTENDED BY SIX BUSINESS DAYS.

SIGNATURES

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

ATP Oil & Gas Corporation

By: /s/ Albert L. Reese Jr.
Albert L. Reese Jr.
Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant in the capacities indicated on March 15, 2012.

Signature	Title
/s/ T. Paul Bulmahn T. Paul Bulmahn	Chairman, Chief Executive Officer and Director (Principal Executive Officer)
/s/ Albert L. Reese Jr. Albert L. Reese Jr.	Chief Financial Officer (Principal Financial Officer)
/s/ Keith R. Godwin Keith R. Godwin	Chief Accounting Officer (Principal Accounting Officer)
/s/ Chris A. Brisack Chris A. Brisack	Director
/s/ Arthur H. Dilly Arthur H. Dilly	Director
/s/ Gerard J. Swonke Gerard J. Swonke	Director
/s/ Walter Wendlandt Walter Wendlandt	Director
/s/ Burt A. Adams Burt A. Adams	Director
/s/ Robert J. Karow Robert J. Karow	Director
/s/ George R. Edwards George R. Edwards	Director
/s/ Brent Longnecker Brent Longnecker	Director

ATP OIL & GAS CORPORATION AND SUBSIDIARIES
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
ATP Oil & Gas Corporation:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of comprehensive income (loss), of shareholders' equity and of cash flows present fairly, in all material respects, the financial position of ATP Oil & Gas Corporation (the Company) and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the accompanying index present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Houston, Texas

March 15, 2012

ATP OIL & GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In Thousands, Except Share Amounts)

	December 31, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 65,678	$ 154,695
Restricted cash	20,113	30,270
Accounts receivable (net of allowance of $225 and $225, respectively)	70,628	92,737
Deferred tax asset	480	8,191
Derivative asset	2,194	1,688
Other current assets	28,050	26,408
Total current assets	187,143	313,989
Oil and gas properties (using the successful efforts method of accounting):		
Proved properties	4,875,232	4,291,440
Unproved properties	22,945	20,402
	4,898,177	4,311,842
Less accumulated depletion, depreciation, impairment and amortization	(1,760,756)	(1,407,206)
Oil and gas properties, net	3,137,421	2,904,636
Restricted cash	10,000	10,000
Deferred financing costs, net	40,873	48,353
Other assets, net	13,337	13,124
Total assets	$ 3,388,774	$ 3,290,102
Liabilities and Equity		
Current liabilities:		
Accounts payable and accruals	$ 265,620	$ 230,703
Current maturities of long-term debt	33,848	21,625
Asset retirement obligation	52,536	43,386
Deferred tax liability	138	–
Derivative liability	68,816	37,893
Current maturities of other long-term obligations	113,657	86,521
Total current liabilities	534,615	420,128
Long-term debt	1,976,157	1,857,784
Other long-term obligations	451,797	472,500
Asset retirement obligation	115,981	123,472
Deferred tax liability	27,493	16,956
Derivative liability	522	6,425
Total liabilities	3,106,565	2,897,265
Commitments and contingencies (Note 12)		
Temporary equity:		
Redeemable noncontrolling interest	115,820	140,851
8% convertible perpetual preferred stock: $0.001 par value; 806,847 issued and outstanding at December 31, 2011; None issued at December 31, 2010; Liquidation value of $80.7 million	70,055	–
Shareholders' equity:		
8% convertible perpetual preferred stock: $0.001 par value, 10,000,000 shares authorized; 2,318,153 issued and outstanding at December 31, 2011; 1,400,000 issued and outstanding at December 31, 2010. Liquidation value of $231.8 million and $140.0 million at December 31, 2011 and 2010, respectively.	222,681	140,000
Common stock: $0.001 par value, 100,000,000 shares authorized; 52,034,547 issued and 51,958,707 outstanding at December 31, 2011; 51,347,163 issued and 51,271,323 outstanding at December 31, 2010	52	51
Additional paid-in capital	529,669	570,739
Accumulated deficit	(548,765)	(356,866)
Accumulated other comprehensive loss	(106,392)	(101,027)
Treasury stock, at cost	(911)	(911)
Total shareholders' equity	96,334	251,986
Total liabilities and equity	$ 3,388,774	$ 3,290,102

See accompanying notes to consolidated financial statements.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In Thousands, Except Per Share Amounts)

	Year Ended December 31,		
	2011	2010	2009
Revenues:			
Oil and gas production	$ 687,208	$ 437,997	$ 298,490
Other	–	–	13,664
	687,208	437,997	312,154
Costs, operating expenses and other:			
Lease operating	122,202	132,544	84,956
Exploration	1,251	1,174	264
General and administrative	43,242	43,948	43,469
Depreciation, depletion and amortization	298,574	220,657	152,780
Impairment of oil and gas properties	57,639	63,267	45,799
Accretion of asset retirement obligation	15,000	13,827	11,676
Drilling interruption costs	19,691	23,647	–
Loss on abandonment	3,916	4,829	2,872
Gain on exchange/disposal of properties	(27,000)	(26,720)	(12,433)
	534,515	477,173	329,383
Income (loss) from operations	152,693	(39,176)	(17,229)
Other income (expense):			
Interest income	223	696	710
Interest expense, net	(326,411)	(222,104)	(40,884)
Derivative income (expense)	25,191	(22,419)	(712)
Gain (loss) on debt extinguishment	1,095	(75,316)	–
	(299,902)	(319,143)	(40,886)
Loss before income taxes	(147,209)	(358,319)	(58,115)
Income tax (expense) benefit:			
Current	1,327	859	(545)
Deferred	(19,395)	35,414	23,079
	(18,068)	36,273	22,534
Net loss	(165,277)	(322,046)	(35,581)
Less income attributable to the redeemable noncontrolling interest	(26,622)	(15,503)	(13,380)
Less convertible preferred stock dividends	(18,583)	(11,248)	(2,856)
Net loss attributable to common shareholders	$ (210,482)	$ (348,797)	$ (51,817)
Net loss per share attributable to common shareholders:			
Basic	$ (4.12)	$ (6.88)	$ (1.24)
Diluted	$ (4.12)	$ (6.88)	$ (1.24)
Weighted average number of common shares:			
Basic	51,077	50,715	41,853
Diluted	51,077	50,715	41,853

See accompanying notes to consolidated financial statements.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In Thousands)

	Year Ended December 31,		
	2011	2010	2009
Net loss	$ (165,277)	$ (322,046)	$ (35,581)
Other comprehensive income (loss):			
Reclassification adjustment for settled hedge contracts (net of taxes of $0, $0 and $859, respectively)	–	–	(859)
Change in fair value of outstanding hedge positions (net of taxes of $0, $0 and ($3,736), respectively)	–	–	3,736
Foreign currency translation adjustment, net of tax	(5,365)	(5,540)	14,390
Other comprehensive income (loss)	(5,365)	(5,540)	17,267
Comprehensive loss	(170,642)	(327,586)	(18,314)
Less income attributable to the redeemable noncontrolling interest	(26,622)	(15,503)	(13,380)
Less convertible preferred stock dividends	(18,583)	(11,248)	(2,856)
Comprehensive loss attributable to common shareholders	$ (215,847)	$ (354,337)	$ (34,550)

See accompanying notes to consolidated financial statements.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)

	Year Ended December 31,		
	2011	2010	2009
Cash flows from operating activities			
Net loss	$ (165,277)	$ (322,046)	$ (35,581)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities –			
Depreciation, depletion and amortization	298,574	220,657	152,780
Impairment of oil and gas properties	57,639	63,267	45,799
Gain on exchange/disposal of properties	(27,000)	(26,720)	(12,433)
Accretion of asset retirement obligation	15,000	13,827	11,676
Deferred income tax expense (benefit)	19,395	(35,414)	(23,079)
Derivative (income) expense	(38,188)	20,090	39,648
(Gain) loss on debt extinguishment	(1,095)	18,973	–
Stock-based compensation	6,683	6,825	7,951
Amortization of deferred revenue	–	(19,336)	(39,893)
Noncash interest expense	35,320	28,078	13,262
Other noncash items, net	(694)	3,245	2,443
Changes in assets and liabilities –			
Accounts receivable and other current assets	59,061	(31,979)	50,402
Accounts payable and accruals	(29,491)	23,213	(53,168)
Other assets and liabilities	(32,836)	40	20
Net cash provided by (used in) operating activities	197,091	(37,280)	159,827
Cash flows from investing activities			
Additions to oil and gas properties	(436,910)	(598,108)	(635,447)
Proceeds from disposition of properties	27,000	17,053	13,000
Decrease (increase) in restricted cash	10,157	(29,766)	(10,504)
Net cash used in investing activities	(399,753)	(610,821)	(632,951)
Cash flows from financing activities			
Proceeds from senior second lien notes	–	1,492,965	–
Proceeds from first lien term loans	59,400	147,000	–
Proceeds from term loan facility–*ATP Titan* assets	91,000	238,750	–
Proceeds from term loans	–	46,000	19,000
Payments of term loans	(25,375)	(1,263,727)	(176,512)
Deferred financing costs	(4,561)	(62,937)	(6,490)
Proceeds from common stock issuances, net of costs	–	–	170,629
Proceeds from preferred stock issuances, net of costs	149,866	–	135,549
Purchase of capped-call options on ATP common stock	(26,500)	–	–
Proceeds from other long-term obligations	85,326	231,888	89,011
Payments of other long-term obligations	(180,848)	(102,818)	(2,298)
Sale of redeemable noncontrolling interest, net of costs	–	–	148,751
Distributions to noncontrolling interest	(45,961)	(14,250)	(18,970)
Preferred stock dividends	(15,098)	(11,276)	–
Derivative contracts, net	67,129	–	–
Other financings, net	(42,534)	(11,180)	–
Exercise of stock options/warrants	205	3,609	3
Net cash provided by financing activities	112,049	694,024	358,673
Effect of exchange rate changes on cash and cash equivalents	1,596	(189)	8,419
Increase (decrease) in cash and cash equivalents	(89,017)	45,734	(106,032)
Cash and cash equivalents, beginning of year	154,695	108,961	214,993
Cash and cash equivalents, end of year	$ 65,678	$ 154,695	$ 108,961

See accompanying notes to consolidated financial statements.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF TEMPORARY EQUITY
(In Thousands)

	2011		2010		2009	
	Shares	Amount	Shares	Amount	Shares	Amount
Redeemable Noncontrolling Interest:						
Balance, beginning of year		$ 140,851		$ 139,598		$ –
Sale of Class A Limited Partner Interest, net of formation costs		–		–		148,751
Income attributable to the redeemable noncontrolling interest		26,622		15,503		13,380
Limited partner distributions		(51,653)		(14,250)		(22,533)
Balance, end of year		$ 115,820		$ 140,851		$ 139,598
8% Convertible Perpetual Preferred Stock						
Balance, beginning of year	–	$ –	–	$ –	–	$ –
Issuance of preferred stock	785	70,667	–	–	–	–
Issuance costs	–	(2,514)	–	–	–	–
Transfer from shareholders' Equity	22	1,902	–	–	–	–
Balance, end of year	807	$ 70,055	–	$ –	–	$ –

See accompanying notes to consolidated financial statements.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(In Thousands)

	2011		2010		2009	
	Shares	Amount	Shares	Amount	Shares	Amount
8% Convertible Perpetual Preferred Stock						
Balance, beginning of year	1,400	$ 140,000	1,400	$ 140,000	–	$ –
Issuance of preferred stock	940	84,583	–	–	1,400	140,000
Transfer to temporary equity	(22)	(1,902)	–	–	–	–
Balance, end of year	2,318	$ 222,681	1,400	$ 140,000	1,400	$ 140,000
Common Stock						
Balance, beginning of year	51,268	$ 51	50,679	$ 51	35,903	$ 36
Issuances of common stock						
Secondary offerings	–	–	–	–	14,565	15
Exercise of stock options/warrants	39	–	418	–	–	–
Restricted stock, net of forfeitures	652	1	171	–	211	–
Balance, end of year	51,959	$ 52	51,268	$ 51	50,679	$ 51
Paid-in Capital						
Balance, beginning of year		$ 570,739		$ 571,595		$ 400,334
Issuances of Company stock						
Secondary common stock offerings		–		–		179,750
Costs of issuances		(2,875)		–		(13,588)
Exercise of stock options/warrants		205		3,567		4
Stock-based compensation		6,683		6,825		7,951
Purchase of capped-call options		(26,500)		–		–
Preferred stock dividends		(18,583)		(11,248)		(2,856)
Balance, end of year		$ 529,669		$ 570,739		$ 571,595
Retained Earnings (Accumulated Deficit)						
Balance, beginning of year		$ (356,866)		$ (19,317)		$ 29,644
Net loss		(165,277)		(322,046)		(35,581)
Income attributable to the redeemable noncontrolling interest		(26,622)		(15,503)		(13,380)
Balance, end of year		$ (548,765)		$ (356,866)		$ (19,317)
Accumulated Other Comprehensive Loss						
Balance, beginning of year		$ (101,027)		$ (95,487)		$ (112,754)
Other comprehensive income (loss)		(5,365)		(5,540)		17,267
Balance, end of year		$ (106,392)		$ (101,027)		$ (95,487)
Treasury Stock, at Cost						
Balance, beginning of year	76	$ (911)	76	$ (911)	76	$ (911)
Balance, end of year	76	$ (911)	76	$ (911)	76	$ (911)
Total Shareholders' Equity		$ 96,334		$ 251,986		$ 595,931

See accompanying notes to consolidated financial statements.

Note 1 — Organization and Basis of Presentation

Organization

ATP Oil & Gas Corporation ("the Company") was incorporated in Texas in 1991. ATP Oil & Gas Corporation is engaged internationally in the acquisition, development and production of oil and natural gas properties. Our management team has extensive engineering, geological, geophysical, technical and operational expertise in developing and operating properties in both our current and planned areas of operation. In the Gulf of Mexico and in the U.K. sector of the North Sea (the "North Sea"), we seek to acquire and develop properties with proved undeveloped reserves ("PUD") that are economically attractive to us but are not strategic to major or large independent exploration-oriented oil and gas companies. Occasionally we will acquire properties that are already producing or where previous drilling has encountered reservoirs that appear to contain commercially productive quantities of oil and gas even though the reservoirs do not meet the SEC definition of proved reserves. In the Gulf of Mexico and North Sea, we believe that our strategy provides assets for us to develop and produce with an attractive risk profile at a competitive cost.

During 2011, we acquired three licenses in the Mediterranean Sea covering potential natural gas resources in the deepwater off the coast of Israel. In the Mediterranean Sea our licenses relate to exploratory prospects where drilling has occurred nearby and hydrocarbons have been discovered by others. Our initial significant capital investment in the Mediterranean Sea is expected to be in the first half of 2012 when drilling exploration begins for one of these three licenses.

Basis of Presentation

The consolidated financial statements include our accounts, the accounts of our majority-owned limited partnership, ATP Infrastructure Partners, L.P. ("ATP-IP") and those of our wholly-owned subsidiaries; ATP Oil & Gas (UK) Limited, or "ATP (UK);" ATP Oil & Gas (Netherlands) B.V.; ATP Energy, Inc., *ATP Titan* LLC, four wholly owned limited liability companies created to own our interests in ATP-IP and *ATP Titan* LLC and four other wholly owned limited liability companies formed related to our operations in the Mediterranean Sea. All intercompany transactions are eliminated in consolidation. We have reclassified certain amounts applicable to prior periods to conform to current classifications. These reclassifications do not affect earnings.

Note 2 — Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in accordance with U.S. generally accepted accounting principles and pursuant to the rules and regulations of the SEC requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosure of contingent assets and liabilities in the financial statements. Actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents primarily consist of cash on deposit and investments in funds with original maturities of three months or less, stated at market value.

Restricted Cash

Restricted cash relates to an escrow account for ATP-IP, discussed below, which holds cash in excess of monthly partnership distributions and operating needs. Also, the *ATP Titan* Facility, discussed below, requires us to maintain in a restricted account a minimum $10.0 million cash balance (classified as noncurrent on the Consolidated Balance Sheet) plus additional amounts based on production at the Telemark Hub to be used for the quarterly debt service of the *ATP Titan* Facility. Occasionally, we also receive cash which is restricted for use to retire certain assets or perform other operations.

Oil and Gas Properties

We account for our oil and gas property costs using the successful efforts accounting method. Under the successful efforts method, lease acquisition costs and intangible drilling and development costs on successful wells and development dry holes are capitalized. Costs of drilling exploratory wells are initially capitalized, but charged to expense if and when a well is determined to be unsuccessful.

Capitalized proved property acquisition costs are depleted on the unit-of-production method on the basis of total estimated units of proved reserves. Capitalized costs relating to producing properties are depleted on the unit-of-production method on the basis of total estimated units of proved developed reserves. When significant development costs (such as the cost of an offshore production platform) are incurred in connection with a planned group of development wells before all of the planned wells have been drilled, it is occasionally necessary to exclude a portion of those development costs in determining the unit-of-production depletion rate until the additional development wells are drilled. However, in no case are future development costs anticipated in computing our depletion rate. Estimated dismantlement, restoration and abandonment costs and estimated residual salvage values are taken into account in determining depletion provisions. Our *ATP Titan* and *ATP Innovator* floating platforms are included in oil and gas properties and depreciated straight line over 40 and 25 years, respectively since they can be relocated to other fields once existing production is depleted. Expenditures for geological and geophysical testing costs are generally charged to expense unless the costs can be specifically attributed to mapping a proved reservoir and determining the optimal placement for future developmental well locations. Expenditures for repairs and maintenance are charged to expense as incurred; renewals and betterments are capitalized. The costs and related accumulated depreciation, depletion, and amortization of properties sold or otherwise retired are eliminated from the accounts, and gains or losses on disposition are reflected in the statements of operations.

We perform impairment analysis whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management's estimates of future oil and gas prices to the estimated future production of oil and gas reserves over the economic life of the property and deducting future costs. Future net cash flows are based upon reservoir engineers' estimates of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions and actual or planned drilling or other development activities. For a property determined to be impaired, an impairment loss equal to the difference between the carrying value and the estimated fair value of the impaired property will be recognized. Fair value, on a depletable unit basis, is estimated to be the present value of the aforementioned expected future net cash flows. Unproved properties are assessed periodically to determine whether they have been impaired. An impairment allowance is provided on an unproved property when we determine that the property will not be developed, but no later than lease expiration. Any impairment charge incurred is recorded in accumulated depletion, depreciation, impairment and amortization to reduce our basis in the asset. Each part of these calculations is subject to a large degree of judgment, including estimated reserves, future net cash flows and fair value.

We recorded impairments during the years ended December 31, 2011, 2010 and 2009 totaling $53.0 million, $42.4 million and $44.6 million, respectively, on certain proved properties in the Gulf of Mexico. We also recorded impairments totaling $1.2 million and $14.9 million during 2011 and 2010, respectively on certain proved properties in the North Sea. The 2011 and 2010 impairments were primarily due to updated performance history. The 2009 impairments were primarily a result of reduced commodity prices and unfavorable operating performance.

Impairments of unproved properties were $3.4 million, $6.0 million and $1.2 million in 2011, 2010 and 2009, respectively, primarily related to surrendered leases in the Gulf of Mexico.

Management's assumptions used in calculating oil and gas reserves or regarding the future net cash flows or fair value of our properties are subject to change in the future. Any change could cause impairment expense to be recorded, impacting our net income or loss and our basis in the related asset. Any change in reserves directly impacts our estimate of future cash flows from the property, as well as the property's fair value. Additionally, as commodity price forecasts change, so too will the estimate of future net cash flows and the fair value estimates.

As of December 31, 2011, there were $9.7 million of capitalized exploratory well costs (suspended well costs) related to two wells in the North Sea which were still being evaluated, and for which drilling was completed in 2010. We are still performing our work program and completing studies that will allow us to calculate estimates of gas in place and potential reserves for Kilmar, part of our Tors development. In 2011, the only change in the suspended well costs was for additions of $0.2 million.

Asset Retirement Obligation

We recognize liabilities associated with the eventual retirement of tangible long-lived assets, upon the acquisition, construction and development of the assets. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Changes in estimates on fully depleted properties are charged directly to loss on abandonment.

Shortages or an increase in cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our abandonment operations, which could have a material adverse effect on our business, financial condition and results of operations. Increased drilling activity in the Gulf of Mexico and the North Sea decreases the availability of offshore rigs and associated equipment. In periods of increased drilling activity in the Gulf of Mexico and the North Sea, we may experience increases in associated costs, including those related to drilling rigs, equipment, supplies and personnel and the services and products of other vendors to the industry. These costs may increase further and necessary equipment and services may not be available to us at economical prices.

We recognize (i) depletion expense on the additional capitalized asset retirement costs; (ii) accretion expense as the present value of the future asset retirement obligation increases with the passage of time, and; (iii) the impact, if any, of changes in estimates of the liability. The following table sets forth a reconciliation of the beginning and ending asset retirement obligation (in thousands):

	December 31,		
	2011	2010	2009
Asset retirement obligation, beginning of year	$ 166,858	$ 150,199	$ 132,108
Liabilities incurred	14,457	5,960	16,220
Liabilities settled	(26,725)	(15,362)	(9,603)
Property dispositions	–	(242)	(292)
Accretion expense	15,000	13,827	11,676
Changes in estimates	(1,073)	12,476	90
Total asset retirement obligation, end of year	168,517	166,858	150,199
Less current portion	(52,536)	(43,386)	(43,418)
Total long-term asset retirement obligation, end of year	$ 115,981	$ 123,472	$ 106,781

During 2011, 2010 and 2009, we recognized loss on abandonment of $3.9 million, $4.8 million and $2.9 million, respectively. These amounts are primarily the result of actual abandonment operations in the Gulf of Mexico requiring more work than originally estimated.

Limited Partnership

On March 6, 2009, along with GE Energy Financial Services ("GE"), we formed ATP-IP to own the *ATP Innovator*, the floating production facility that currently serves our Mississippi Canyon Block 711 Gomez Hub properties. We contributed the *ATP Innovator* in exchange for a 49% subordinated limited partner interest, a 2% general partner interest and cash. GE paid $150.0 million to ATP-IP for a 49% Class A limited partner interest. We remain the operator and continue to hold a 100% working interest in the Gomez field and its oil and gas reserves. The transaction was effective June 1, 2008 and allows us exclusive use of the *ATP Innovator* during the term of the Platform Use Agreement ("PUA"), which is expected to be the economic life of the Gomez Hub reserves.

From an operational standpoint, during the term of the PUA, we are obligated to pay to ATP-IP a per unit fee for all hydrocarbons processed by the *ATP Innovato*r, subject to a minimum throughput fee of $53,000 per day. Such minimum fees, if applicable, can be recovered by us in future periods whenever fees owed during a month exceed the minimum due. We may also be subject to a minimum fee of $53,000 per day for up to 180 days under certain circumstances, including if we fail to provide the minimum notification period before the Gomez field ceases production. We made no other performance guarantees to GE and the ultimate fees earned by ATP-IP beyond the minimum fees will be determined by the volumes of hydrocarbons processed through the facility. During the term of the PUA, we are responsible for all of the operating costs and periodic maintenance of the *ATP Innovator*. ATP-IP pays us a monthly fee for certain administrative services we provide to the partnership.

We have entered a period under the agreements when all of the cash distributions from the partnership are paid to the Class A limited partner until such time as they have achieved the return of their invested capital plus a specified return. Once those amounts have been received by the Class A limited partner, all cash distributions will be made to the general partner and subordinated limited partner (ATP's interests) until specified amounts have been received. At the conclusion of the special distribution periods, all partners will again share in distributions proportionately according to their ownership in the partnership.

For financial reporting purposes, because we are the general partner of the partnership, we consolidate ATP-IP, along with three wholly owned limited liability companies (the "LLCs") we created to own our interests in ATP-IP. The GE Class A limited partner interest is reflected as a noncontrolling interest in our consolidated financial statements. Under the provisions of our limited partnership agreement with ATP-IP, we could be required to repurchase the Class A limited partner interest if certain change of control events were to occur. If a change of control were to become probable in a future period, we would be required to adjust the carrying amount of the redeemable noncontrolling interest to its redemption amount, to the extent it differed from the carrying amount, at the time the change of control was deemed to be probable. We do not currently believe a change of control is probable.

Capitalized Interest

Interest costs during the construction phase of certain long-term assets are capitalized and amortized over the related assets' estimated useful lives. Interest expense capitalized during the last three years and the properties to which it relates is set forth in the following table (in thousands):

	Year Ended December 31,		
	2011	2010	2009
ATP Titan – Telemark (Gulf of Mexico)	$ –	$ 40,400	$ 102,200
Octabuoy – Cheviot (North Sea)	29,246	12,900	7,900
Total capitalized interest	$ 29,246	$ 53,300	$ 110,100

Deferred Financing Costs

Costs incurred in connection with the issuance of long-term debt and other obligations are capitalized and amortized to interest expense over the term of the related agreement, using the effective interest method.

Environmental Liabilities

Environmental liabilities are recognized when the expenditures are considered probable and can be reasonably estimated. Measurement of liabilities is based on currently enacted laws and regulations, existing technology and undiscounted site-specific costs. Generally, such recognition would coincide with a commitment to a formal plan of action. We have no accruals for such liabilities at December 31, 2011 or 2010.

Revenue Recognition

We use the sales method of accounting for oil and natural gas revenues. Under this method, revenues are recognized based on actual volumes of oil and gas sold to purchasers. The volumes sold may differ from the volumes to which we are entitled based on our interests in the properties. Differences between volumes sold and entitled volumes create oil and gas imbalances which are generally reflected as adjustments to reported proved oil and gas reserves and future cash flows in our supplemental oil and gas disclosures. If our excess takes of oil or natural gas exceed our estimated remaining proved reserves for a property, an oil or natural gas imbalance liability is recorded in the consolidated balance sheet.

Drilling Interruption Costs

Drilling interruption costs represent the costs we have incurred as a result of the deepwater drilling moratoriums and subsequent drilling permit delays caused by the April 2010 Deepwater Horizon incident in the Gulf of Mexico. During 2011, we incurred $19.7 million stand-by costs related to drilling operations at our Telemark and Gomez Hubs. During 2010 a side-track well operation in 7,000 feet of water was interrupted when the moratorium was imposed and work on that project stopped, resulting in the early termination of a drilling contract. In the course of obtaining a full release from our obligations under the contract, we incurred net costs of $8.7 million. Additionally, because the necessary deepwater drilling permits were not issued, drilling interruption costs during 2010 also include $14.9 million of stand-by costs related to drilling operations at our Telemark and Gomez Hubs.

Concentration of Credit Risk

We extend credit, primarily in the form of uncollateralized oil and gas sales and joint interest owners' receivables, to various companies in the oil and gas industry, which results in concentrations of credit risk. Concentrations of credit risk may be affected by changes in economic or other conditions within our industry and may accordingly impact our overall credit risk. However, we believe that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of the companies to which we extend credit.

Major Customers

Historically, we have sold our oil and natural gas production to a relatively small number of purchasers. We are not dependent upon, or confined to, any one purchaser or small group of purchasers. Due to the nature of oil and natural gas markets and because oil and natural gas are commodities and there are numerous purchasers in the areas in which we sell production, we do not believe the loss of a single purchaser, or a few purchasers, would materially affect our ability to sell our production.

For the year ended December 31, 2011, revenues from two purchasers accounted for 67% and 20%, respectively, of oil and gas production revenues. For the year ended December 31, 2010, revenues from four purchasers accounted for 65%, 12%, 11% and 5%, respectively, of oil and gas production revenues. For the year ended December 31, 2009, revenues from four purchasers accounted for 39%, 33%, 13% and 7%, respectively, of oil and gas production revenues. A substantial portion of our oil and gas production revenues in the North Sea are from one customer.

Translation of Foreign Currencies

The local currency is the functional currency for our foreign subsidiaries, and as such, assets and liabilities are translated into U.S. dollars at year-end exchange rates. Income and expense items are translated at average exchange rates during the year. The gains or losses resulting from such translations are deferred and included in accumulated other comprehensive income as a separate component of shareholders' equity. Gains and losses arising from transactions denominated in a currency other than the functional currency of a particular entity are included in net income. At December 31, 2011, accumulated other comprehensive loss consisted of $106.4 million of loss related to cumulative foreign currency translation adjustments.

Insurance Recoveries

When realized, insurance recoveries under our loss of production income policy are reported as other revenues in the consolidated statements of operations and in cash flows from operating activities in the consolidated statements of cash flows. During 2009 insurance recoveries of $13.7 million were related to disruptions caused by Hurricane Ike in 2008.

Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences or benefits attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and for operating loss and tax credit carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes that enactment date. A valuation allowance is recorded to reduce deferred tax assets to an amount that management believes is more likely than not to be realized in future years.

Stock-based Compensation

We recognize stock-based compensation expense as vesting of the stock award occurs. Generally, restricted stock awards vest over three years and common stock option awards vest evenly over four years.

Fair Value of Financial Instruments

For cash and cash equivalents, receivables and payables, the carrying amounts approximate fair value because of the short maturity of these instruments.

Derivative Instruments

We utilize derivative instruments and fixed-price forward sales contracts with respect to a portion of our expected production in order to manage our exposure to oil and natural gas price volatility. These instruments expose us to risk of financial loss if:

- production is less than expected for forward sales contracts;
- the counterparty to the derivative instrument defaults on its contract obligations; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and the actual prices received for our production at the physical sales point.

Our results of operations may be negatively impacted in the future by our derivative instruments and fixed-price forward sales contracts as these instruments may limit any benefit we would otherwise receive from increases in the prices for oil and natural gas.

We primarily utilize fixed-price physical forward contracts, price swaps, prepaid swaps, price collars and put and call options which are generally placed with major financial institutions or with counterparties of high credit quality in order to minimize our credit risks. The oil and natural gas reference prices of these commodity derivative contracts are based upon oil and natural gas market exchanges which have a high degree of historical correlation with the actual prices we receive. All derivative instruments are recorded on the balance sheet at fair value with changes in fair value recorded as a component of derivative income (expense) in our consolidated statement of operations. Cash settlements of our derivative instruments are classified as operating cash flows unless the derivative contains a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying Consolidated Statements of Cash Flows.

From time to time, we utilize foreign currency and interest rate derivative instruments to mitigate risks associated with our foreign operations and borrowings, respectively.

Recently Issued Accounting Pronouncements

In May 2011, the FASB issued guidance which will result in common fair value measurement and disclosure requirements in GAAP and International Financial Reporting Standards. For public entities, the guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. We expect to adopt the provisions for the quarter ended March 31, 2012 and we do not anticipate that this will have a material impact on our financial position or results of operations.

In June 2011, the FASB issued guidance which eliminates the option to present components of other comprehensive income as part of the statement of changes in shareholders' equity and requires that all nonowner changes in shareholders' equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. We have adopted the provisions of this standard at December 31, 2011 and it has not had a material impact on our financial statements.

In December 2011, the FASB deferred the provisions that relate to the presentation of reclassification adjustments. For public entities, the guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011.

In December 2011, the FASB issued guidance related to disclosure of information about offsetting and related arrangements for financial instruments and derivative instruments recognized as assets and liabilities. The guidance is effective for fiscal years and interim periods within those years, beginning after January 1, 2013. We expect to adopt the provisions for the quarter ending March 31, 2013 and we do not anticipate that this will have a material impact on our financial position or results of operations.

Note 3 — Risks and Uncertainties

Since May 2010 when the federal government imposed the first of a series of moratoriums on drilling in the Gulf of Mexico, we have faced unparalleled difficulties in obtaining permits to continue our development programs. Prior to the moratoriums, we anticipated developing and bringing to production three additional wells at our Telemark Hub and two additional wells at our Gomez Hub by the end of 2010. It has taken until the first quarter of 2012 for us to bring to production all of the three additional wells at the Telemark Hub and, during the third quarter of 2011, the two wells planned for the Gomez Hub were postponed to late 2012/early 2013.

The new wells that have been placed on production have taken longer to complete and bring to production than originally planned and one of them has not produced at rates that were previously projected. In addition, we have incurred capital and operating costs higher than we expected primarily due to additional regulations imposed since the Deepwater Horizon incident and the requirement to perform sidetracks on two of the wells. The new wells helped us achieve production growth in 2011, and we forecast production and operating cash flow growth in 2012 as development activity continues. While cash flows were lower than previously projected due to lower than expected production rates, delays in bringing on new production and higher capital costs, we continued our development operations by supplementing our cash flows from operating activities with funds raised through various transactions (see the Consolidated Statement of Cash Flows.) Our planned operations for 2012 reflect our expectations for production based on actual production history, new production expected to be brought online, the development delays at Telemark and Gomez Hubs discussed above, the deferral of certain capital expenditures, the continuation of commodity prices near current levels, the higher anticipated costs associated with maintaining existing production and bringing new production online, and the higher cost of servicing our additional financing and other obligations.

As of December 31, 2011, we had a working capital deficit of $347.5 million. To preserve our development momentum in the negative working capital environment that we experienced throughout 2011, we have increased our term loans, issued convertible perpetual preferred stock, granted net profits interests (NPI's) to certain of our vendors, sold NPI's and dollar-denominated overriding royalty interests (Overrides) in our properties to investors, and we have entered into prepaid swaps against our future production that provided cash proceeds to us at closing. We have negotiated with the constructor of the hull of the Octabuoy in China to defer the majority of our payments until the hull is ready to be moved to the North Sea, currently scheduled to be during 2013. A similar arrangement is in place for the Octabuoy topside equipment, which is being constructed by the same company in China.

As operator of all of our projects that require cash commitments within the next twelve months and beyond, we retain significant control over the development concept and its timing. We consider the control and flexibility afforded by operating our properties under development to be instrumental to our business plan and strategy. To manage our liquidity, we have delayed certain capital commitments, and within certain constraints, we can continue to conserve capital by further delaying or eliminating future capital commitments. While postponing or eliminating capital projects will delay or reduce future cash flows from scheduled new production, this control and flexibility is one method by which we can match, on a temporary basis, our capital commitments to our available capital resources.

Our cash flow projections are highly dependent upon numerous assumptions including the timing and rates of production from our new wells, the sales prices we realize for our oil and natural gas, the cost to develop and produce our reserves, our ability to monetize our properties and future production through asset sales and financial derivatives, and a number of other factors, some of which are beyond our control. Our inability to increase near-term production levels and generate sufficient liquidity through the actions noted above could result in our inability to meet our obligations as they come due which would have a material adverse affect on us. In the event we do not achieve the projected production and cash flow increases, we will attempt to fund any short-term liquidity needs through other financing sources; however, there is no assurance that we will be able to do so in the future if required to meet any short-term liquidity needs. We believe we can continue to meet our obligations for at least the next twelve months through a combination of cash flow from operations, continuing to sell or assign interests in our properties and selling forward our production through the financial derivatives markets, and if necessary, further delaying certain development activities..

Despite our anticipated production growth, we remain highly leveraged. Servicing our debt and other long-term obligations will continue to place significant constraints on us and makes us vulnerable to adverse economic and industry conditions. Specifically, certain of our financing and derivative transactions require us to make payments in future periods from the proceeds (or net profits) from the sale of production. While these financing transactions have enabled us to continue the development of our properties and meet current operating needs, they will significantly burden the future net cash flows from our production until these obligations are satisfied. (See Note 7, "Other Long-term Obligations," and Note 13, "Derivative Instruments and Risk Management Activities" for further details.)

Our estimates of proved oil and natural gas reserves and the estimated future net revenues from such reserves are based upon various assumptions, including assumptions relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The estimation process requires significant assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise and the quality and reliability of this data can vary. Estimates of our oil and natural gas reserves and the costs and timing associated with developing these reserves are subject to change, and may differ materially from our actual results. A substantial portion of our total proved reserves are undeveloped and recognition of such reserves requires us to expect that capital will be available to fund their development. The size of our operations and our capital expenditures budget limit the number of properties that we can develop in any given year and we intend to continue to develop these reserves, but there is no assurance we will be successful. Development of these reserves may not yield the expected results, or the development may be delayed or the costs may exceed our estimates, any of which may materially affect our financial position, results of operations, cash flows, the quantity of proved reserves that we report, and our ability to meet the requirements of our financing obligations.

A substantial portion of our current production is concentrated among relatively few wells located offshore in the Gulf of Mexico and in the North Sea, which are characterized by production declines more rapid than those of conventional onshore properties. As a result, we are particularly vulnerable to a near-term severe impact resulting from unanticipated complications in the development of, or production from, any single material well or infrastructure installation, including lack of sufficient capital, delays in receiving necessary drilling and operating permits, increased regulation, reduced access to equipment and services, mechanical or operational failures, and bad weather. Any unanticipated significant disruption to, or decline in, our current production levels or prolonged negative changes in commodity prices or operating cost levels could have a materially adverse effect on our financial position, results of operations, cash flows, the quantity of proved reserves that we report, and our ability to meet our commitments as they come due.

Oil and natural gas development and production in the Gulf of Mexico are regulated by the Bureau of Ocean Energy Management ("BOEM") and the Bureau of Safety and Environmental Enforcement ("BSEE") of the Department of the Interior, collectively, formerly known as the Bureau of Ocean Energy Management, Regulation and Enforcement. Our near-term operating and development plans in the Gulf of Mexico, as well as our longer-term business plan, are dependent upon receiving regulatory approvals for deepwater drilling and other permits required by the BSEE. Delays in the permitting process directly impact the timing of our development and production activities, and can materially affect our financial position, results of operations, cash flows, and the quantity of proved reserves that we report.

We cannot predict future changes in laws and regulations governing oil and gas operations in the Gulf of Mexico. New regulations issued since the Deepwater Horizon incident in 2010 have changed the way we conduct our business and increased our costs of developing and commissioning new assets. We incurred additional costs in 2010 from the deepwater drilling moratoriums, subsequent drilling permit delays and additional inspection and commissioning costs. Some of these additional costs continued into 2011 and are projected to continue into 2012. Should there be additional significant future regulations or additional statutory limitations, they could require further changes in the way we conduct our business, further increase our costs of doing business or ultimately prohibit us from drilling for or producing hydrocarbons in the Gulf of Mexico. Additionally, we cannot influence or predict if or how the governments of other countries in which we operate may modify their regulatory regimes from time to time.

As an independent oil and gas producer, our revenue, profitability, cash flows, proved reserves and future rate of growth are substantially dependent on prevailing prices for oil and natural gas. Historically, the energy markets have been very volatile, and we expect such price volatility to continue. Any extended decline in oil or gas prices could have a materially adverse effect on our financial position, results of operations, cash flows, the quantities of oil and gas reserves that we can economically produce, and may restrict our ability to obtain additional financing or to meet the contractual requirements of our debt and other obligations.

Note 4 — Supplemental Disclosures of Cash Flow Information

Supplemental disclosures of cash flow information (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Cash paid during the year for interest, net of amounts capitalized	$288,214	$192,697	$ 16,536
Cash received during the year for income taxes	–	–	13,581
Noncash investing and financing activities:			
Increase in noncash property additions	64,469	86,491	187,880
Accrued distributions to noncontrolling interest	5,692	–	3,563
Accrued preferred stock dividends	3,485	(28)	2,856

Note 5 — Oil and Gas Properties

Acquisitions

During June 2011, we acquired interests in three deepwater licenses in the Mediterranean Sea off the coast of Israel for approximately $1.7 million. We will operate the licenses with initial working interests of 40%. During November and December 2011, we acquired an aggregate additional 45% interest in GC 300 at our Clipper property from partners in the project. We now operate that property with a 100% working interest.

Dispositions

During December 2011, we sold to a third party our 100% working interest in the deep operating rights of one of our Gulf of Mexico properties resulting in a $26.0 million gain.

Note 6 — Long-term Debt

Long-term debt consisted of the following (in thousands):

	December 31, 2011	December 31, 2010
First lien term loans, net of unamortized discount of $2,460 and $2,644, respectively,	$ 204,703	$ 146,607
Senior second lien notes, net of unamortized discount of $4,671 and $6,071, respectively,	1,495,329	1,493,929
Term loan facility – *ATP Titan* assets, net of unamortized discount of $16,373 and $10,760, respectively,	309,973	238,873
Total debt	2,010,005	1,879,409
Less current maturities	(33,848)	(21,625)
Total long-term debt	$ 1,976,157	$ 1,857,784

Senior Second Lien Notes

In April 2010, we issued senior second lien notes (the "Notes") in an aggregate principal amount of $1.5 billion, due May 1, 2015. The Notes bear interest at an annual rate of 11.875%, payable each May 1 and November 1, and contain restrictions that, among other things, limit the incurrence of additional indebtedness, mergers and consolidations, and certain restricted payments.

At any time (which may be more than once), on or prior to May 1, 2013, the Company may, at its option, redeem up to 35% of the outstanding Notes with money raised in certain equity offerings, at a redemption price of 111.9%, plus accrued interest, if any. In addition, the Company may redeem the Notes, in whole or in part, at any time before May 1, 2013 at a redemption price equal to par plus an applicable make-whole premium plus accrued and unpaid interest to the date of redemption. The Company may also redeem any of the Notes at any time on or after May 1, 2013, in whole or in part, at specified redemption prices, plus accrued and unpaid interest to the date of redemption.

The Notes also contain a provision allowing the holders thereof to require the Company to purchase some or all of those Notes at a purchase price equal to 101% of their aggregate principal amount, plus accrued and unpaid interest to the date of repurchase, upon the occurrence of specified change of control events.

First Lien Term Loans

In June 2010, we entered into a first lien credit agreement (the "Credit Facility") with an initial balance of $150.0 million, due October 15, 2014, to replace the previous credit facility. Initial proceeds of the Credit Facility were $144.3 million, net of original issue discount and transaction fees. Principal outstanding under the term loans issued pursuant to the Credit Facility initially bore interest at an annual rate of 11.0%. The Company granted the lenders a security interest in and a first lien on not less than 80% of its proved oil and gas reserves in the Gulf of Mexico, capital stock of material subsidiaries (limited in the case of the Company's non-U.S. subsidiaries to not more than 65% of the capital stock) and certain infrastructure assets, a portion of which has since been released in connection with the ATP Titan LLC financing discussed below. In February 2011, we entered into Incremental Loan Assumption Agreement and Amendment No. 1, relating to our First Lien Credit Agreement, dated as of June 18, 2010 to, among other things, decrease the interest rate on the entire balance outstanding from 11% to 9%. Additional borrowings were $60.0 million ($58.0 million, net of transaction costs and discount). Quarterly principal payments are required equal to ½% of remaining principal balance until June 18, 2014 and the remaining principal balance is due January 15, 2015.

The Notes and Credit Facility contain certain negative covenants which place limits on the Company's ability to, among other things:

- incur additional indebtedness;
- pay dividends on the Company's capital stock or purchase, repurchase, redeem, defease or retire the Company's capital stock or subordinated indebtedness;
- make investments outside of our normal course of business;
- incur liens;
- create any consensual restriction on the ability of the Company's restricted subsidiaries to pay dividends, make loans or transfer property to the Company;
- engage in transactions with affiliates;
- sell assets; and
- consolidate, merge or transfer assets.

Term Loan Facility - ATP Titan Assets

In September 2010, we formed ATP Titan LLC ("Titan LLC"), a wholly owned and operated subsidiary which we consolidate in our financial statements, and transferred to it our 100% ownership of the *ATP Titan* platform and related infrastructure assets. Simultaneous with the transfer, Titan LLC entered into a $350.0 million term loan facility (the "*ATP Titan* Facility"). Under the initial agreement and the First and Second Amendments to Term Loan Agreement and Limited Waivers entered into in March and September 2011, respectively, we have now drawn down the entire amount available receiving proceeds of $317.9 million, net of discount and direct issuance costs. The *ATP Titan* Facility bears interest at LIBOR (floor of 0.75%) plus 8%. Principal payments are required equal to 2.25% (of original principal) per quarter until October 4, 2012, and 2.5% thereafter until final maturity at September 2017. The *ATP Titan* Facility requires us to maintain in a restricted account a minimum $10.0 million cash balance plus additional amounts based on production at the Telemark Hub to be used for the quarterly debt service of the *ATP Titan* Facility. The *ATP Titan* Facility is collateralized solely by the *ATP Titan* and related infrastructure assets (net book value at December 31, 2011 of $1,105.9 million) and the outstanding member interests in Titan LLC, which are all owned indirectly by the Company. The *ATP Titan* Facility includes a customary condition that there has not occurred a material adverse change with respect to the Company. The Company remains operator and 100% owner of the *ATP Titan* platform, related infrastructure assets and the working interest in its Telemark Hub oil and gas reserves.

The Credit Facility and the Notes contain customary events of default, and if certain of those events of default were to occur and remain uncured, such as a failure to pay principal or interest when due, our lenders could terminate future lending commitments under the Credit Facility, and our lenders could declare the outstanding borrowings due and payable. The Credit Facility also contains an event of default if there has occurred a material adverse change with respect to the Company's compliance with environmental requirements and applicable laws and regulations. The *ATP Titan* Facility contains standard events of default and an event of default if there has occurred a material adverse change with respect to the Company. The *ATP Titan* Facility also contains provisions that provide for cross defaults among the documents entered into in connection with the *ATP Titan* Facility and acceleration of Titan LLC's payment obligations under the *ATP Titan* Facility in certain situations. In addition, our hedging arrangements contain standard events of default, including cross default provisions, that, upon a default, provide for (i) the delivery of additional collateral, (ii) the termination and acceleration of the hedge, (iii) the suspension of the lenders' obligations under the hedging arrangement or (iv) the setoff of payment obligations owed between the parties.

The effective annual interest rate and fair value of our long-term debt was 12.0% and $1.5 billion, respectively, at December 31, 2011. Accrued interest payable was $37.7 million and $34.8 million at December 31, 2011 and 2010, respectively.

Note 7 — Other Long-term Obligations

Other long-term obligations consisted of the following (in thousands):

	December 31, 2011	December 31, 2010
Net profits interests	$ 336,669	$ 331,776
Dollar-denominated overriding royalty interests	42,324	52,825
Gomez pipeline obligation	71,676	73,868
Vendor deferrals – Gulf of Mexico	17,493	7,096
Vendor deferrals – North Sea	94,710	90,874
Other	2,582	2,582
Total	565,454	559,021
Less current maturities	(113,657)	(86,521)
Other long-term obligations	$ 451,797	$ 472,500

Net Profits Interests – Beginning in 2009, we have granted dollar-denominated overriding royalty interests in the form of net profits interests ("NPIs") in certain of our proved oil and gas properties in and around the Telemark Hub, Gomez Hub and Clipper to certain of our vendors in exchange for oil and gas property development services and to certain finance entities in exchange for cash proceeds. During April 2011, we closed an NPI transaction in the Telemark Hub for $40.0 million. The purchaser acquired an existing vendor NPI for $19.7 million, thereby extinguishing the existing NPI liability of $20.8 million, and contributed an additional $20.3 million toward the development of the Telemark Hub in exchange for a larger percentage of the net profits from production at the Telemark Hub that will continue until the purchaser recovers $40.0 million, plus an overall rate of return.

The interests granted are paid solely from the net profits, as defined, of the subject properties. As the net profits increase or decrease, primarily through higher or lower production levels and higher or lower prices of oil and natural gas, the payments due the holders of the net profits interests increase or decrease accordingly. If there is no production from a property or if the net profits are negative during a payment period, no payment would be required. We also accrete the liability over the estimated term in which the NPI is expected to be settled using the effective interest method with related interest expense presented net of amounts capitalized on the Consolidated Statements of Operations. The term of the NPIs is dependent on the value of the services contributed by these vendors or the cash proceeds contributed by the finance companies coupled with the timing of production and future economic conditions, including commodity prices and operating costs. Upon recovery of the agreed rate of return, the NPIs terminate. Because NPIs were granted on proved properties where production is reasonably assured, we have accounted for these NPI's as financing obligations on our Consolidated Balance Sheets. As such, the reserves and production revenues associated with the NPIs are retained by the Company. We expect approximately 60%, or $205 million of the NPIs to be repaid over the next 12 months based on anticipated production, commodity prices and operating costs.

Dollar-denominated Overriding Royalty Interests – During April, June and December 2011, we sold, for an aggregate of $65.0 million, three dollar-denominated overriding royalty interests ("Overrides") in our Gomez Hub properties similar to those sold in 2009 and 2010. These Overrides obligate us to deliver proceeds from the future sale of hydrocarbons in the specified proved properties until the purchasers achieve a specified return. As the proceeds from the sale of hydrocarbons increase or decrease, primarily through changes in production levels and oil and natural gas prices, the payments due the holders of the overriding royalty interests will increase or decrease accordingly. If there is no production from a property during a payment period, no payment would be required. The percentage of property revenues available to satisfy these obligations is dependent upon certain conditions specified in the agreement. Upon recovery of the agreed rate of return, the Overrides terminate and our interest increases accordingly. Because of the explicit rate of return, dollar-denomination and limited payment terms of the Overrides, they are reflected in the accompanying financial statements as financing obligations. As such, the reserves and production revenues are retained by the Company. Related interest expense is presented net of amounts capitalized on the Consolidated Statements of Operations. As of December 31, 2011, if there is sufficient production from a certain property, we will incur up to $7.2 million of contingent interest costs. We expect approximately 93%, or $39 million of the Overrides to be repaid over the next 12 months based on anticipated production and commodity prices.

Gomez Pipeline Obligation – In 2009, we sold to a third party for net proceeds of $74.5 million the oil and natural gas pipelines that service the Gomez Hub. In conjunction with the sale, we entered into agreements with the purchaser to transport our oil and natural gas production for the remaining production life of our fields serviced by the *ATP Innovator* production platform for a per-unit fee that is subject to a minimum monthly payment through December 31, 2016. Such minimum fees, if applicable, can be recovered by ATP in future periods within the same calendar year whenever fees owed during a month exceed the minimum due. We remain the operator of the pipeline and are responsible for all of the related operating costs. As a result of the retained asset retirement obligation and the purchaser's option to convey the pipeline back to us at the end of the life of the fields in the Gomez Hub, the transaction has been accounted for as a financing obligation equal to the net proceeds received. This obligation is being amortized based on the estimated proved reserve life of the Gomez Hub properties using the effective interest method with related interest expense presented net of amounts capitalized on the Consolidated Statements of Operations. All payments made in excess of the minimum fee in future periods will be reflected as interest expense of the financing obligation.

Vendor Deferrals – In the Gulf of Mexico, in addition to the NPIs exchanged for development services described above, we have negotiated with certain other vendors involved in the development of the Telemark and Gomez Hubs to partially defer payments over a twelve-month period beginning with first production. We accrue the present value of the deferred payments and accrete the balance over the estimated term in which it is expected to be paid using the effective interest method with related interest expense presented net of amounts capitalized, on the Consolidated Statements of Operations.

In the U.K. North Sea, development of our interest in the Cheviot field continues. During February 2012, we entered into an amendment to one of our agreements for the construction and delivery of the Octabuoy hull and topside utility module to align the payments with the new expected delivery date of the hull. As amended, the agreements provide for a $41.1 million payment in the first quarter of 2012 and $228.9 million in 2013. As work is completed and amounts are earned under the amended agreement, we record obligations and related interest expense, net of amounts capitalized, on the Consolidated Financial Statements.

Effective Interest Rate – The weighted average effective interest rate on our other long-term obligations set forth above was 18.9% and 16.7% at December 31, 2011 and 2010, respectively.

Note 8 — Equity

Preferred Stock

In September 2009, we issued 1.4 million shares of convertible preferred stock and received net proceeds of $135.5 million ($100 per share before underwriters' discounts and commissions and offering expenses). In June 2011, we issued 1.7 million shares of 8% convertible perpetual preferred stock ("Series B Preferred Stock") and received net proceeds of $123.3 million ($90 per share before underwriters' discounts and commissions, option contract costs (discussed below) and offering expenses). The Series B Preferred Stock has terms and features which are substantially identical to the convertible preferred stock issued in 2009 (collectively, the "Preferred Stock"). Each share of convertible preferred stock is perpetual, has no voting rights, has a liquidation preference of $100, pays cumulative dividends at an annual rate of 8% payable in cash, shares of our common stock, or a combination thereof, and is convertible at any time, at the option of the holder, into 4.5045 shares of common stock. After September 30, 2014, we have the option to force conversion to common stock provided that the prevailing common stock market price exceeds the conversion price by 150% on average for a stipulated period of time. In the event of certain fundamental changes of the Company, each share of convertible preferred stock is subject to adjustment to prevent dilution and would receive a conversion benefit as defined in the related statement of resolutions that established the convertible preferred stock. In December 2011, we announced a quarterly cash dividend of $6.3 million ($2.02 per share of preferred stock) which was paid in January 2012.

In conjunction with issuance of the Series B Preferred Stock, we purchased for $26.5 million capped-call options ("Options") to cover all 14.1 million shares of common stock issuable upon conversion of the Series B Preferred Stock and the preferred stock we issued in 2009. The Options allow us to prevent dilution due to common stock issuance upon preferred stock conversion up to a price per common share of $27.50. The shares of common stock acquirable under the Options are indexed to our common stock price at the time of exercise and the Options can only be settled in common stock. As a result, the purchase price of the Options is recorded as a component of additional paid-in capital within Shareholders' Equity in the accompanying Consolidated Financial Statements.

At December 31, 2011, a portion of the Series B Preferred Stock is classified as temporary equity because, in the event of certain fundamental changes, as defined in the statement of resolutions, the Company could be required to issue in the aggregate more shares of common stock pursuant to the conversion ratio most favorable to the holders than currently are authorized and unissued (the "Common Share Shortfall"). The value of the temporary equity is deemed to be the number of shares of Preferred Stock that would account for such common share shortfall times the $86.83 fair value per share (net of issuance costs of $3.17 per share). This amount is revalued in each reporting period as the Common Share Shortfall changes, and at such time as we have sufficient authorized and unissued common shares to satisfy the most favorable conversion obligation possible under the statement of resolutions, this amount will be reclassified to permanent equity.

Common Stock

During 2009, we issued 14.6 million shares of common stock and received net proceeds of $170.6 million (an average of $12.31 per share before underwriters' discounts and commissions and offering expenses).

Rights Plan

On October 1, 2005, the Board of Directors of ATP authorized the issuance of one preferred share purchase right (a "Right") with respect to each outstanding share of common stock, par value $0.001 per share (the "Common Shares"), of the Company (the "Shareholder Rights Plan"). The Rights were issued on October 17, 2005 to the holders of record of Common Shares on that date. Each Right entitles the registered holder to purchase from the Company one one-hundredth (1/100) of a share of Junior Participating Preferred Stock, par value $0.001 per share (the "Preferred Shares"), of the Company at a price of $150 per one one-hundredth of a Preferred Share, subject to adjustment. The description and terms of the Rights are set forth in a Rights Agreement dated as of October 11, 2005 between the Company and American Stock Transfer & Trust Company, as Rights Agent.

Note 9 — Stock-Based and Other Compensation Plans

In January 2001, the Board of Directors approved the 2000 Stock Plan (the "2000 Plan") and in June 2010 the Shareholders approved the 2010 Stock Plan (the "2010 Plan") to provide increased incentive for the Company's employees and directors. The 2000 Plan authorized the granting of options and restricted stock awards for up to 4,000,000 shares of common stock, and expired in February 2011. The 2010 Plan authorizes the granting of options, restricted stock awards, restricted stock bonus awards and performance share bonus awards for up to an aggregate 6,000,000 shares of common stock. Generally, options are granted at prices equal to at least 100% of the fair value of the stock at the date of grant, expire not later than five years from the date of grant and vest ratably over a four-year period following the date of grant. From time to time, as approved by the Board of Directors, options with differing terms have also been granted. We recognized stock option compensation expense of $2.6 million, $2.5 million and $3.0 million for the years ended December 31, 2011, 2010 and 2009, respectively.

The fair values of options granted during the years ended December 31, 2011, 2010 and 2009 were estimated at the date of grant using a Black-Scholes option-pricing model assuming no dividends and with the following weighted average assumptions for grants during the periods indicated:

	Year Ended December 31,		
	2011	2010	2009
Weighted average volatility	87%	84%	76%
Expected term (in years)	3.8	3.8	3.8
Risk-free rate	1.1%	1.0%	1.7%
Weighted average fair value of options – grant date	$7.94	$5.53	$8.81

Volatilities are based on the historical volatility of our closing common stock price. Expected term of options granted represents the period of time that options granted are expected to be outstanding. The expected term of the options granted in 2011, 2010 and 2009 is estimated using the simplified method because the option terms are homogeneous and the Company has insufficient option exercise history to refine its expectations. The risk-free rate for periods within the contractual life of the options is based on the comparable U.S. Treasury rates in effect at the time of each grant. The aggregate intrinsic values of options exercised during the years ended December 31, 2011, 2010 and 2009 were $0.4 million, $0.4 million and $0, respectively. The following table sets forth a summary of option transactions for the year ended December 31, 2011:

	Number of Options	Weighted Average Grant Price	Aggregate Intrinsic Value (1) ($000)	Weighted Average Remaining Contractual Life (in years)
Outstanding at beginning of year	1,521,291	$ 23.31		
Granted	476,510	13.15		
Exercised	(34,927)	6.15		
Canceled	(110,950)	20.78		
Expired	(173,687)	38.27		
Outstanding at end of year	1,678,237	19.40	$ 577	2.8
Vested and expected to vest	1,465,761	20.12	$ 489	2.7
Options exercisable at end of year	680,967	29.17	$ 201	1.6

(1) Based upon the difference between the market price of the common stock on the last trading day of the year and the option exercise price of in-the-money options.

A summary of the status of ATP's nonvested stock options as of December 31, 2011 and changes during the year is presented below:

	Number of Options	Weighted Average Grant-date Fair Value
Nonvested at beginning of year	933,972	$ 6.98
Granted	476,510	7.94
Vested	(331,307)	8.21
Forfeited	(81,905)	7.79
Nonvested at end of year	997,270	6.97

At December 31, 2011, unrecognized compensation expense related to nonvested stock option grants totaled $3.3 million. Such unrecognized expense will be recognized as vesting occurs over a weighted average period of 2.6 years.

Restricted stock grants vest over a three-year period, are subject to forfeiture, and cannot be sold, transferred or disposed of during the restriction period. The holders of the shares have voting and dividend rights with respect to such shares. During the years ended December 31, 2011, 2010 and 2009, we recognized aggregate compensation expense of $4.1 million, $4.3 million and $4.9 million, respectively, related to outstanding restricted stock grants.

The following table sets forth the changes in nonvested restricted stock for the year ended December 31, 2011:

	Number of Shares	Weighted Average Grant-date Fair Value	Aggregate Intrinsic Value (1) ($000)
Nonvested at beginning of year	422,637	$ 19.76	
Granted	658,611	11.40	
Forfeited	(6,154)	16.25	
Vested	(243,065)	24.65	
Nonvested at end of year	832,029	11.74	$ 6,124

(1) Based upon the closing market price of the common stock on the last trading day of the year.

At December 31, 2011, unrecognized compensation expense related to restricted stock totaled $5.2 million. Such unrecognized expense will be recognized as vesting occurs over a weighted average period of 2.3 years.

We have a 401(k) Savings Plan which covers all domestic employees. At our discretion, we may match a certain percentage of the employees' contributions to the plan. The matching percentage is currently 100% of the first 3% and 50% of the next 2% of each participant's compensation. Our matching contributions to the plan were approximately $302,000, $299,000 and $289,000 for the years ended December 31, 2011, 2010 and 2009, respectively.

We also have a defined contribution plan for our U.K. employees. We currently contribute 4% to the plan and such contributions are subject to the Pensions Act 1999 (U.K.) and to U.K. rules on taxation. For the years ended December 31, 2011, 2010 and 2009, we contributed approximately $34,000, $29,000 and $33,000, respectively.

Note 10 — Earnings Per Share

Basic earnings per share ("EPS") is computed by dividing net income or loss attributable to common shareholders by the weighted average number of common shares (other than nonvested restricted stock) outstanding during the period. Weighted average shares outstanding for diluted EPS also includes a hypothetical number of additional shares ("Common Stock Equivalents") calculated assuming the exercise or conversion of all in-the-money options, warrants and convertible preferred stock and full vesting of restricted stock awards. Common Stock Equivalents are excluded from the computation of weighted average common shares outstanding when the per share effect is antidilutive. The impact of assumed conversion of preferred stock on net income attributable to common shareholders is excluded from the computation of EPS when its impact is antidilutive.

Basic and diluted EPS are computed based on the following information (in thousands, except per share amounts):

	Year Ended December 31, 2011	2010	2009
Net loss attributable to common shareholders:			
Net loss attributable to common shareholders	$ (210,482)	$ (348,797)	$ (51,817)
Add impact of assumed preferred stock conversions (if-converted method)	–	–	–
Net loss attributable to common shareholders and impact of assumed conversions	$ (210,482)	$ (348,797)	$ (51,817)
Weighted average shares outstanding:			
Weighted average number of shares outstanding - basic	51,077	50,715	41,853
Effect of potentially dilutive securities:			
Stock options and warrants	–	–	–
Nonvested restricted stock	–	–	–
Preferred stock	–	–	–
Weighted average number of shares outstanding - diluted	51,077	50,715	41,853
Net loss per share attributable to common shareholders:			
Basic	$ (4.12)	$ (6.88)	$ (1.24)
Diluted	$ (4.12)	$ (6.88)	$ (1.24)

The following were excluded from diluted EPS because their inclusion would have been antidilutive (in thousands):

	Year Ended December 31, 2011	2010	2009
Net loss attributable to common shareholders:			
Preferred stock dividends	$ 18,583	$ 11,248	$ 2,856
Weighted average shares outstanding:			
Common stock equivalents	427	500	300
Assumed conversion of preferred stock	10,458	6,300	1,600
Out-of-the-money stock options	1,018	1,100	1,100

Note 11 — Income Taxes

Income tax (expense) benefit consisted of the following (in thousands):

	Year Ended December 31, 2011	2010	2009
Current:			
Domestic	$ -	$ 924	$ (924)
Foreign	1,327	(65)	379
	1,327	859	(545)
Deferred:			
Domestic	58,057	117,459	19,809
Foreign	(15,334)	12,790	4,570
	42,723	130,249	24,379
Valuation allowance	(62,118)	(94,835)	(1,300)
Total income tax (expense) benefit	$ (18,068)	$ 36,273	$ 22,534

Income (loss) before income taxes consisted of the following (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Domestic	$ (142,330)	$ (329,497)	$ (46,860)
Foreign	(4,879)	(28,822)	(11,255)
	$ (147,209)	$ (358,319)	$ (58,115)

The reconciliation of income tax computed at the U.S. federal statutory tax rates to the provision for income taxes is as follows:

	Year Ended December 31,		
	2011	2010	2009
Statutory federal income tax rate	35.00%	35.00%	35.00%
Nondeductible and other	(0.13)	(0.80)	(3.63)
Foreign operations	(11.28)	0.88	1.52
Impact of redeemable noncontrolling interest	6.33	1.51	8.06
Valuation allowance	(42.19)	(26.47)	(2.18)
	(12.27%)	10.12%	38.77%

Included in 2011 foreign operations is the effect of an increase in the UK statutory tax rate from 20% to 30% resulting in a decrease of 8.28% to the effective tax rate benefit on the current year pretax book loss.

Significant components of our deferred tax assets (liabilities) as of December 31, 2011 and 2010 are as follows (in thousands):

	December 31, 2011		
	U.S.	Foreign	Total
Deferred tax asset:			
Net operating loss carry forwards	$ 190,883	$ 297,338	$488,221
Unrealized derivative loss	1,250	–	1,250
Alternative minimum tax credit	1,841	–	1,841
Stock-based compensation	5,047	435	5,482
Asset retirement obligation	12,289	–	12,289
Other	563	–	563
Valuation allowance	(155,442)	(5,418)	(160,860)
Deferred tax asset	56,431	292,355	348,786
Deferred tax liability:			
Oil and gas property basis differences	(55,588)	(317,591)	(373,179)
Other	(843)	(1,915)	(2,758)
Deferred tax liability	(56,431)	(319,506)	(375,937)
Net deferred tax liability	–	(27,151)	(27,151)
Less net current deferred tax liability	–	138	138
Less net current deferred tax asset	(480)	–	(480)
Noncurrent deferred tax liability	$ (480)	$ (27,013)	$ (27,493)

	December 31, 2010		
	U.S.	Foreign	Total
Deferred tax asset:			
Net operating loss carry forwards	$ 215,174	$ 178,882	$ 394,056
Unrealized derivative loss	13,356	–	13,356
Alternative minimum tax credit	1,840	–	1,840
Stock-based compensation	5,064	211	5,275
Asset retirement obligation	10,918	–	10,918
Other	572	–	572
Valuation allowance	(97,385)	(1,676)	(99,061)
Deferred tax asset	149,539	177,417	326,956
Deferred tax liability:			
Oil and gas property basis differences	(143,431)	(186,182)	(329,613)
Other	(6,108)	–	(6,108)
Deferred tax liability	(149,539)	(186,182)	(335,721)
Net deferred tax liability	–	(8,765)	(8,765)
Less net current deferred tax asset	(8,191)	–	(8,191)
Noncurrent deferred tax liability	$ (8,191)	$ (8,765)	$ (16,956)

We compute income taxes using an asset and liability approach which results in the recognition of deferred tax liabilities and assets for the expected future tax consequences of temporary differences between the carrying amounts and the tax basis of those assets and liabilities. As of December 31, 2011 and 2010, for U.S. tax provision purposes, we have provided valuation allowance for that portion of excess tax benefits resulting from stock options and restricted stock outstanding as of the date we adopted the accounting standards for stock-based compensation. Beginning December 31, 2010, for U.S. tax provision purposes, we have also provided valuation allowance for the remainder of our net deferred tax assets based on our cumulative net losses. Additionally, the deferred tax asset related to the U.S. net operating loss carry forwards ("NOLs") as disclosed does not include an additional $19.9 million of net operating loss, as reflected in our U.S. Income Tax Return and net operating loss carry forwards in relation to excess tax benefits on stock option exercises and restricted stock vested through the fiscal year ended December 31, 2011.

No tax expense is provided on the income attributable to the redeemable noncontrolling interest in ATP Infrastructure Partners, LP, as the partnership is a pass-through entity and is not subject to federal income taxes. Taxes attributable to the income of the redeemable noncontrolling interest would be the liability of the ultimate taxpayers owning that interest.

At December 31, 2011 and 2010, we had U.S. net operating loss carry forwards ("NOLs") for financial statement purposes of approximately $545.3 million and $614.8 million, respectively, which begin to expire in 2024. ATP (UK) had NOLs of $936.8 million and $678.5 million available for corporate tax carry-forward at December 31, 2011 and 2010, respectively, which are presented in Foreign Operations above. As of December 31, 2011 we have a net current deferred tax asset of approximately $0.5 million, which is primarily attributable to bad debt reserve and unrealized hedging losses.

The U.K. supplementary charge of corporation tax was increased from 20% to 32%, effective March 24, 2011, and Royal Assent was received on July 19, 2011. The U.K. rate increase has been reflected in the income tax provision as of December 31, 2011. All U.K. deferred tax assets and liabilities subject to the supplementary charge of corporation tax have been updated to reflect the 32% rate as of December 31, 2011.

At December 31, 2011 and 2010, for Netherlands' income tax provision purposes, we had a valuation allowance of $4.9 million and $1.7 million, respectively, related to the net operating loss carryovers generated in 2011 and in prior periods. If activity, development and acquisitions increase within the Dutch sector, we will reevaluate this valuation allowance.

At December 31, 2011 for Israeli income tax provision purposes, we have a valuation allowance of $0.5 million related to the net operating loss carryover generated in 2011. Since 2012 will be the first year of active drilling and operations in this area, there is insufficient evidence of future taxable profits.

The Company and its subsidiaries file income tax returns in the United States federal jurisdiction, two states, the U.K., the Netherlands and Israel. Our open tax years in our major jurisdictions are from 2003 to current. As of December 31, 2011, we are not aware of any uncertain tax positions requiring adjustments to our tax liability. If applicable, we will record to the income tax provision any interest and penalties related to unrecognized tax positions.

U.S. deferred taxes have not been recognized with respect to foreign income of $54.4 million that is permanently reinvested internationally. We currently do not have any foreign tax credits available to reduce U.S. taxes on this income if it was repatriated.

Note 12 — Commitments and Contingencies

The development, production and sale of oil and natural gas in the Gulf of Mexico and in the North Sea are subject to extensive laws and regulations, including environmental laws and regulations. We may be required to make large expenditures to comply with environmental and other governmental regulations. Under these laws and regulations, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that substantially increase our costs (see the discussion in Note 3, "Risks and Uncertainties"). Accordingly, any of these liabilities, penalties, suspensions, terminations or regulatory changes could materially adversely affect our financial condition and results of operations. We believe that we are in compliance with all of the laws and regulations which apply to our operations.

Under the provisions of our limited partnership agreement with ATP-IP, we could be required to repurchase the Class A limited partner interest if certain change of control events were to occur. If a change of control were to become probable in a future period, we would be required to adjust the carrying amount of the redeemable noncontrolling interest to its redemption amount, to the extent it differed from the carrying amount, at the time the change of control was deemed to be probable. We do not currently believe a change of control is probable.

We are a party to a multi-year (life of reserves) firm transportation agreement covering certain production in the North Sea that requires us to pay a pipeline tariff on our nominated contract quantity of natural gas during the contract period, whether or not the volumes are delivered to the pipeline. For any contract period where actual deliveries fall short of contract quantities, we can make up such amounts by delivering volumes over the subsequent four years free of tariff, within certain limitations. While we control our nominations, we are subject to the risk we may be required to prepay or ultimately pay transportation on undelivered volumes.

In the normal course of business, we occasionally purchase oil and gas properties for little or no up-front costs and instead commit to pay consideration contingent upon the successful development and operation of the properties. The contingent consideration generally includes amounts to be paid upon achieving specified operational milestones, such as first commercial production and again upon achieving designated cumulative sales volumes. At December 31, 2011, the aggregate amount of such contingent commitments related to unmet operational milestones was $7.8 million. During 2010, we paid $2.4 million of additional consideration for two of our North Sea properties under a similar provision.

We maintain insurance to protect the Company and its subsidiaries against losses arising out of our oil and gas operations. Our insurance includes coverage for physical damage to our offshore properties, general (third party) liability, workers compensation and employers liability, seepage and pollution and other risks. Our insurance includes various limits and deductibles or retentions, which must be met prior to or in conjunction with recovery. Additionally, our insurance is subject to the terms, conditions and exclusions of such policies.

For losses emanating from offshore operations, we have up to an aggregate of $2.5 billion of various insurance coverages with individual policy limits ranging from $1.0 million to over $500 million each. While we maintain insurance levels, deductibles and retentions that we believe are prudent and responsible, there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages.

In general, our current insurance policies cover physical damage to our oil and gas assets. The coverage is designed to repair or replace assets damaged by insurable events.

Our excess liability policies generally provide coverage (dependent on the asset) for bodily injury and property damage, including coverage for negative environmental effects such as seepage and pollution. This liability coverage would cover claims for bodily injury or death brought against the company by or on behalf of individuals who are not employees of the company. The liability limits scale to either our operating interest or the total insured interest including nonoperating partners.

Our energy insurance package includes coverage for operator's extra expense, which provides coverage for control of well, re-drill and pollution arising from a covered event. We maintain a $150 million Oil Spill Financial Responsibility policy in order to provide a Certificate of Financial Responsibility to the BSEE under the requirements of the Oil Pollution Act of 1990. Additionally, as noted above, our excess liability policies provide coverage (dependent on the asset) for bodily injury and property damage, including coverage for negative environmental effects such as seepage and pollution. Legislation has been proposed but has not passed to increase the limit of the Oil Spill Financial Responsibility policy required for the certificate and there is no assurance that we will be able to obtain this insurance should that happen.

The occurrence of a significant accident or other event not fully covered by our insurance could have a materially adverse effect on our operations and financial condition. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance at levels that would provide enough funds for us to continue operating without access to other funds. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. Because third-party contractors and other service providers are used in our offshore operations, we may not realize the full benefit of worker's compensation laws in dealing with their employees. In addition, pollution and environmental risks generally are not fully insurable.

On January 29, 2010, Bison Capital Corporation ("Bison") filed suit against ATP in the United States District Court for the Southern district of New York alleging ATP owed fees totaling $102 million to Bison under a February 2004 agreement. The case was tried in January 2011. On March 8, 2011 the Court entered a judgment in favor of Bison for $1.65 million plus prejudgment interest and Bison's reasonable attorney's fees. ATP provided for this judgment in the financial statements as of December 31, 2010. Subsequently, Bison gave notice that it would appeal the judgment. By September 16, 2011, both Bison and ATP filed their respective briefs with the United States Court of Appeals for the Second Circuit. The case remains active pending resolution by the appellate court.

We are, in the ordinary course of business, involved in various other legal proceedings from time to time. Management does not believe that the outcome of these proceedings as of December 31, 2011, either individually or in the aggregate, will have a material adverse effect on our financial condition, results of operations or cash flows.

Note 13 — Derivative Instruments and Price Risk Management Activities

At December 31, 2011, we had the following derivative contracts in place:

Period	Type	Volumes	Price $/Unit	Net Fair Value Asset (Liability) (1) Current ($000)	Net Fair Value Asset (Liability) (1) Noncurrent ($000)
Oil (Bbl) – *Gulf of Mexico*					
2012	Swaps	3,408,250	95.87	(20,115)	–
2013	Swaps	90,000	90.40	–	(522)
2012	Prepaid Swaps (2)	476,950	–	(48,424)	–
Total				(68,539)	(522)
Natural Gas (MMBtu)					
North Sea					
2012	Swaps	1,646,000	8.48	(213)	–
Gulf of Mexico					
2012	Calls (3)	3,660,000	5.35	(64)	–
2012	Fixed-price physicals	1,365,000	4.64	2,194	–
Total				1,917	–
Total asset				2,194	–
Total liability				(68,816)	(522)
Total				(66,622)	(522)

(1) None of the derivatives outstanding is designated as a hedge for accounting purposes.

(2) In order to manage our exposure to oil price volatility and provide a current source of financing, in the second half of 2011, we entered into certain off-market oil swap derivative contracts which provide us with $87.9 million of cash advances from the counterparty and obligate us to pay market prices at the time of settlement.

(3) During the first quarter of 2011, we sold U.S. gas call options and received premiums of $2.1 million.

At December 31, 2010, we had the following derivative contracts in place:

Period	Type	Volumes	Price	Net Fair Value Asset (Liability) (2) Current	Noncurrent
			$/Unit (1)	($000)	($000)
Oil (Bbl) – *Gulf of Mexico*					
2011	Swaps	2,124,500	81.99	(23,084)	–
2012	Swaps	1,120,750	89.37	–	(4,236)
2013	Swaps	90,000	90.40	–	(199)
2011	Swaps (3)	911,000	78.41	(12,027)	–
Total				$ (35,111)	$ (4,435)
Natural Gas (MMBtu)					
North Sea					
2011	Swaps	1,641,000	7.21	(2,782)	–
2012	Swaps	1,464,000	8.20	–	(1,249)
Gulf of Mexico					
2011	Fixed-price physicals	5,025,000	4.78	1,030	–
2012	Fixed-price physicals	1,365,000	4.64	–	(741)
2011	Collars	1,350,000	4.75-7.95	658	–
Total				$ (1,094)	$ (1,990)
Derivative asset				$ 1,688	$ –
Derivative liability				(37,893)	(6,425)
Total				$ (36,205)	$ (6,425)

(1) Unit price for collars reflects the floor and the ceiling prices, respectively.

(2) None of the derivatives outstanding is designated as a hedge for accounting purposes.

(3) These swaps include call options to allow us to participate in per barrel price increases above $111.00.

During the first quarter of 2011, we sold certain natural gas call options in exchange for a premium from the counterparties. At settlement of a call option, if the market price exceeds the strike price of the call option, the Company pays the counterparty such excess. If the market price settles below the strike price of the call option, no payment is due from either party. Cash settlements of our derivative instruments are classified as operating cash flows unless the derivative contains a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying Consolidated Statements of Cash Flows.

There was no other comprehensive income related to hedges during 2011 or 2010. The following AOCI table shows where gains, net of taxes, on cash flow hedge derivatives were reported in the year ended December 31, 2009 (in thousands):

AOCI for cash flow hedges – December 31, 2008	$ (2,877)
Derivative gains	3,736
Gains reclassified from AOCI to oil and gas revenues	(859)
AOCI for cash flow hedges – December 31, 2009	$ –

During the year ended December 31, 2011, we paid net cash settlements of $13.0 million related to our derivatives. Additional information about derivatives is presented in Note 15 "Fair Value Measurements". Our derivative income (expense) is based entirely on nondesignated derivatives and consists of the following (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Realized gains (losses) from:			
Settlements of contracts	$ (23,317)	$ (2,686)	$ 18,335
Early terminations of contracts	10,700	–	19,226
Unrealized gains (losses) on open contracts	37,808	(19,733)	(38,273)
Derivative income (expense)	$ 25,191	$ (22,419)	$ (712)

Note 14 — Segment Information

The Company's operations are focused in the Gulf of Mexico and in the North Sea. Management reviews and evaluates separately the operations of its Gulf of Mexico segment and its North Sea segment. The operations of both segments include natural gas and liquid hydrocarbon production and sales. The accounting policies of the reportable segments are the same as those described in Note 2 to the Consolidated Financial Statements. Segment activity for the years ended December 31, is as follows (in thousands):

	Gulf of Mexico	North Sea	Total
2011			
Revenues	$ 668,184	$ 19,024	$ 687,208
Depreciation, depletion and amortization	285,966	12,608	298,574
Impairment of oil and gas properties	56,401	1,238	57,639
Gain on disposal of properties	27,000	–	27,000
Drilling interruption costs	19,691	–	19,691
Income (loss) from operations	159,317	(6,625)	152,692
Interest income	223	–	223
Interest expense, net	326,411	–	326,411
Derivative income	23,373	1,818	25,191
Gain on debt extinguishment	1,095	–	1,095
Income tax expense	–	(18,068)	(18,068)
Additions to oil and gas properties	332,873	211,042	543,915
Total assets	2,830,027	558,747	3,388,774
2010			
Revenues	$ 416,836	$ 21,161	$ 437,997
Depreciation, depletion and amortization	200,457	20,200	220,657
Impairment of oil and gas properties	48,392	14,875	63,267
Gain on exchange/disposal of properties	26,720	–	26,720
Drilling interruption costs	23,647	–	23,647
Loss from operations	16,071	23,105	39,176
Interest income	243	453	696
Interest expense, net	222,104	–	222,104
Derivative expense	(16,253)	(6,166)	(22,419)
Loss on debt extinguishment	(75,316)	–	(75,316)
Income tax benefit	24,023	12,250	36,273
Additions to oil and gas properties	570,393	139,890	710,283
Total assets	2,896,486	393,616	3,290,102

	Gulf of Mexico	North Sea	Total
2009			
Revenues	$ 295,124	$ 17,030	$ 312,154
Depreciation, depletion and amortization	128,777	24,003	152,780
Impairment of oil and gas properties	45,799	–	45,799
Gain (loss) on disposal of properties	13,177	(744)	12,433
Income (loss) from operations	3,825	(21,054)	(17,229)
Interest income	537	173	710
Interest expense, net	40,884	–	40,884
Derivative income (expense)	(9,834)	9,122	(712)
Income tax benefit	18,885	3,649	22,534
Additions to oil and gas properties	721,793	96,386	818,179
Total assets	2,545,876	257,271	2,803,147

Note 15 — Fair Value Measurements

The accounting standards for fair value measurement and disclosure applies to all financial assets and financial liabilities that are being measured and reported on a fair value basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The standards establish a framework for measuring fair value and expand disclosure about fair value measurements. The standards require fair value measurements be classified and disclosed in one of the following categories:

Level 1: Measured based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.

Level 2: Measured based on quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that we value using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). Our option pricing models are industry-standard and consider various inputs including forward commodity price estimates, volatility and time value of money.

Financial assets and liabilities are classified based on the lowest level input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and determines the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The fair values of our derivative contracts are classified as Level 3 based on the significant unobservable inputs into our expected present value models (see Note 13, "Derivative Instruments and Price Risk Management Activities"). The following table sets forth a reconciliation of changes in the fair value of these financial assets (liabilities) during the year ended December 31, 2011 (in thousands):

	U.S. Gas Fixed-Price Physicals	U.S. Gas Calls	U.S. Oil Swaps(1)	U.S. Oil Swaps(2)	U.S. Gas Price Collars	U.K. Gas Swaps	Total
Balance at beginning of period	$ 289	$ –	$ (27,519)	$ (12,027)	$ 658	$ (4,031)	$ (42,630)
Derivative gains included in earnings	5,351	2,069	7,329	8,373	170	1,899	25,191
Sales	–	(2,133)	(86,646)	–	–	–	(88,779)
Settlements and terminations	(3,446)	–	37,775	3,654	(828)	1,919	39,074
Balance at end of period	$ 2,194	$ (64)	$ (69,061)	$ –	$ –	$ (213)	$ (67,144)
Changes in unrealized gain (loss) included in derivative income (expense) relating to derivatives still held at December 31, 2011	$ 2,935	$ (64)	$ (5,284)	$ –	$ –	$ 1,036	$ (1,377)

(1) In 2011, we entered into certain off-market oil swap derivative contracts which provide us with $87.9 million of cash advances from the counterparty (of which $1.2 million will be received in 2012) and obligate us to pay market prices at the time of settlement.

(2) These swaps were matched with call options to allow us to reparticipate in price increases above certain levels.

The following table sets forth a reconciliation of changes in the fair value of these financial assets (liabilities) during the year ended December 31, 2010 (in thousands):

	U.S Gas Fixed-Price Physicals	U.S Gas Price Collars	U.S. Oil Swaps	U.S Oil Swaps(1)	U.K. Gas Swaps	Total
Balance at beginning of period	$ (778)	$ (339)	$ (7,837)	$ (14,910)	$ –	$ (23,864)
Derivative gains (losses) included in earnings	9,161	3,727	(24,276)	(4,090)	(5,751)	(21,229)
Settlements and terminations	(8,094)	(2,730)	4,594	6,973	1,720	2,463
Balance at end of period	$ 289	$ 658	$ (27,519)	$ (12,027)	$ (4,031)	$ (42,630)
Changes in unrealized gain (loss) included in derivative income (expense) relating to derivatives still held at December 31, 2010	$ 289	$ 1,170	$ (21,892)	$ (10,520)	$ (4,031)	$ (34,984)

(1) These swaps were matched with call options to allow us to reparticipate in price increases above certain levels.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Oil and gas properties are measured at fair value on a nonrecurring basis upon impairment and when acquired in a nonmonetary property exchange. During 2011, we recorded impairment expense of $57.6 million related to oil and gas properties. During 2010, we recorded impairment expense of $63.3 million related to oil and gas properties and gain on nonmonetary property exchange of $12.0 million related to proved Gulf of Mexico properties. The impairment charges reduce the oil and gas properties' carrying values to their estimated fair values and are classified as Level 3. Fair value is calculated as the estimated discounted future net cash flows attributable to the assets. The gain on nonmonetary property exchange reflects the difference between the carrying value of the property surrendered and the estimated fair value of the property received which is classified as Level 3 and which is calculated based on the estimated discounted future net cash flows attributable to that asset.

The Company's primary assumptions in preparing the estimated discounted future net cash flows to be recovered from oil and gas properties are based on (i) proved reserves and risk-adjusted probable and possible reserves, (ii) commodity forward-curve prices and assumptions as to costs and expenses, and (iii) the estimated discount rate that would be used by potential market participants to determine the fair value of the assets.

Note 16 —Subsequent Events

Our evaluation has identified the following matters which require disclosure as events subsequent to December 31, 2011:

During 2012 through March 9, we sold for $65 million certain Overrides in our Gomez Hub. Similar to previous Overrides sold by us, the purchasers receive a designated portion of the revenues produced at the Gomez Hub until they have obtained the amount of their investment plus a designated return. Once payout of the Overrides has been achieved, the interests revert back to us. In March 2012, we entered into certain commodity price derivatives contracts which have provided us with net cash advances of $19.4 million and obligate us to pay market prices at the time of settlement. See also the discussion in Note 7, Other Long-term Obligations of changes to deferred payments related to our Cheviot field in the North Sea.

On March 9, 2012, we entered into Amendment and Restatement and Incremental Loan Assumption Agreement to the Credit Facility ("The Amendment"). The Amendment provides for an increase to the principal amount of the Credit Facility from $210 million to the lesser of $365.0 million or 10% of the Company's Adjusted Consolidated Net Tangible Assets, as defined. The amendment also reduces the interest rate of the Credit Facility from 9% fixed to a floating rate of 8.75% calculated based on a Libor floor of 1.50% plus 7.25%. The other terms of the Credit Facility are essentially unchanged by the Amendment.

Note 17 —Supplemental Quarterly Financial Information (Unaudited)
(In Thousands, Except Per Share Amounts)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2011				
Revenues	$ 166,500	$ 172,883	$ 170,135	$ 177,690
Costs, expenses and other (1)	144,894	177,906	124,441	87,275
Income (loss) from operations	21,606	(5,023)	45,694	90,415
Net loss attributable to common shareholders	(119,547)	(56,852)	(5,591)	(28,492)
Net loss per share attributable to common shareholders (2):				
Basic	(2.34)	(1.11)	(0.11)	(0.56)
Diluted	(2.34)	(1.11)	(0.11)	(0.56)
2010				
Revenues	$ 93,029	$ 101,099	$ 102,121	$ 141,748
Costs, expenses and other (1)	76,715	116,513	91,773	192,172
Income (loss) from operations	16,314	(15,414)	10,348	(50,424)
Net loss attributable to common shareholders (3)	(886)	(82,919)	(58,350)	(206,642)
Net loss per share attributable to common shareholders (2):				
Basic	(0.02)	(1.63)	(1.15)	(4.06)
Diluted	(0.02)	(1.63)	(1.15)	(4.06)

(1) Included here is impairment of oil and gas properties the most significant amounts of which are in the second quarter of 2011 and fourth quarter of 2010 when impairment was $45.7 million and $48.2 million, respectively.

(2) The sum of the per share amounts per quarter does not equal the total for the year due to changes in the average number of common shares outstanding.

(3) In the second quarter of 2010, we refinanced our long-term debt and recognized a loss on debt extinguishment of $78.2 million. Also in the second quarter of 2010, we completed construction of the *ATP Titan* and therefore ceased capitalizing related interest costs.

Oil and Gas Reserves and Related Financial Data (Unaudited)

Capitalized Costs Related to Oil and Gas Producing Activities

The following table summarizes capitalized costs related to our oil and gas operations as of December 31 (in thousands):

	Gulf of Mexico	North Sea	Total
2009			
Oil and gas properties:			
Unproved	$ 12,219	$ 1,691	$ 13,910
Proved	3,261,445	347,686	3,609,131
Accumulated depletion, depreciation, impairment and amortization	(1,025,741)	(111,528)	(1,137,269)
	$ 2,247,923	$ 237,849	$ 2,485,772
2010			
Oil and gas properties:			
Unproved	$ 9,249	$ 11,153	$ 20,402
Proved	3,813,325	478,115	4,291,440
Accumulated depletion, depreciation, impairment and amortization	(1,265,217)	(141,989)	(1,407,206)
	$ 2,557,357	$ 347,279	$ 2,904,636
2011			
Oil and gas properties:			
Unproved	$ 10,711	$ 12,234	$ 22,945
Proved	4,214,573	660,659	4,875,232
Accumulated depletion, depreciation, impairment and amortization	(1,633,234)	(127,522)	(1,760,756)
	$ 2,592,050	$ 545,371	$ 3,137,421

Costs Incurred

The following table sets forth certain information with respect to costs incurred in connection with our oil and gas producing activities during the years ended December 31 (in thousands):

	Gulf of Mexico	North Sea	Total
2009			
Unproved property acquisition costs	$ 161	$ 4	$ 165
Development costs	712,531	95,922	808,453
Exploration expenses	233	31	264
Oil and gas expenditures	$ 712,925	$ 95,957	$ 808,882
2010			
Property acquisition costs:			
Proved	$ 20,283	$ –	$ 20,283
Unproved	625	–	625
Development costs	533,553	139,890	673,443
Exploration expenses	1,165	9	1,174
Oil and gas expenditures	$ 555,626	$ 139,899	$ 695,525
2011			
Unproved property acquisition costs	$ 1,461	$ 1,082	$ 2,543
Development costs	374,754	210,278	585,032
Exploration expenses	1,034	217	1,251
Oil and gas expenditures	$ 377,249	$ 211,577	$ 588,826

ATP OIL & GAS CORPORATION AND SUBSIDIARIES
SUPPLEMENTAL DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES

Results of Operations for Oil and Gas Producing Activities

The results of operations for oil and gas producing activities for the years ended December 31 below exclude general and administrative expenses, interest charges and other non operating items except income tax expense which was determined by applying the statutory rates to pretax operating results (in thousands).

	Gulf of Mexico	North Sea	Total
2009			
Oil and gas production	$ 281,460	$ 17,030	$ 298,490
Other revenues	13,664	–	13,664
Total revenues	295,124	17,030	312,154
Lease operating	74,973	9,983	84,956
Exploration	233	31	264
Depreciation, depletion and amortization	128,777	24,003	152,780
Impairment of oil and gas properties	45,799	–	45,799
Accretion of asset retirement obligation	10,441	1,235	11,676
Loss on abandonment	2,872	–	2,872
(Gain) loss on disposal of properties	(13,177)	744	(12,433)
Income (loss) before income taxes	45,206	(18,966)	26,240
Income tax (expense) benefit	(15,822)	9,484	(6,338)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 29,384	$ (9,482)	$ 19,902
2010			
Oil and gas production revenues	$ 416,836	$ 21,161	$ 437,997
Lease operating	126,394	6,150	132,544
Exploration	1,165	9	1,174
Depreciation, depletion and amortization	200,457	20,200	220,657
Impairment of oil and gas properties	48,392	14,875	63,267
Accretion of asset retirement obligation	12,466	1,361	13,827
Drilling interruption costs	23,647	–	23,647
Loss on abandonment	4,829	–	4,829
Gain on disposal of properties	(26,720)	–	(26,720)
Income (loss) before income taxes	26,206	(21,434)	4,772
Income tax (expense) benefit	(9,172)	10,717	1,545
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 17,034	$ (10,717)	$ 6,317
2011			
Oil and gas production revenues	$ 668,184	$ 19,024	$ 687,208
Lease operating	116,792	5,410	122,202
Exploration	1,034	217	1,251
Depreciation, depletion and amortization	285,966	12,608	298,574
Impairment of oil and gas properties	56,401	1,238	57,639
Accretion of asset retirement obligation	13,773	1,227	15,000
Drilling interruption costs	19,691	–	19,691
Loss on abandonment	3,916	–	3,916
Gain on disposal of properties	(27,000)	–	(27,000)
Income (loss) before income taxes	197,611	(1,676)	195,935
Income tax (expense) benefit	(69,164)	838	(68,326)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 128,447	$ (838)	$ 127,609

Oil and Natural Gas Reserves

Proved reserves are the estimated 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 economic conditions, operating methods, and government regulations. Reservoirs are considered proved if shown to be economically producible by either actual production or conclusive formation tests.

In December 2008, the SEC issued its final rule, "Modernization of Oil and Gas Reporting" (Release Nos. 33-8995; 34-59192; FR-78). The disclosure requirements under the final rule became effective for this filing for the year ended December 31, 2009. The final rule changed a number of oil and gas reserve estimation and disclosure requirements under SEC Regulations S-K and S-X. Subsequently, the FASB updated Extractive Industries — Oil and Gas (Topic 932) to align the oil and gas reserves estimation and disclosure requirements with the SEC's final rule. Among the principal changes affecting us in the final rule are requirements to use estimated future sales prices based on a first-of-month 12-month arithmetic average price for reserve estimation and disclosure instead of a single end-of-year price; the ability to use new reliable technologies to establish reasonable certainty of proved reserves; expanding proved undeveloped reserves disclosures, including a discussion of proved undeveloped reserves that have remained undeveloped for five years or more; and the requirement to disclose the qualifications of the chief technical person who oversees the company's overall reserves estimation process.

We have applied this guidance effective at December 31, 2009 in the supplemental oil and gas information presented below and under **Item 2 *Properties***. The adoption of these new rules has been treated as a change in accounting principle that is inseparable from a change in accounting estimate, as it is impracticable to estimate the impact of the new rules because of the cost and resources required to prepare duplicate reserve valuations. Beginning with 2009, the first-of-month 12-month average prices for crude oil and natural gas for 2009 were lower than the subsequent year-end spot prices applicable under the old rules. Because of the changes in assumptions, the 2009 and beyond reserve valuations below may not be comparable to those of prior years.

In all years presented, 100% of our reserves were prepared by independent petroleum engineers. As of December 31, 2011, we use Collarini Associates and Ryder Scott Company, L.P. The following table sets forth our net proved oil and NGL and gas reserves (all from traditional resources) at December 31, 2008, 2009, 2010 and 2011 and the related changes for the years ended December 31, 2009, 2010 and 2011:

	Oil and NGL[1] (MBbls)			Natural Gas (MMcf)			Equivalent Barrels (MBoe)		
	Gulf of Mexico	North Sea	Total	Gulf of Mexico	North Sea	Total	Gulf of Mexico	North Sea	Total
Proved Reserves at December 31, 2008	39,811	25,502	65,313	210,759	110,986	321,745	74,937	44,000	118,937
Revisions of previous estimates (2)	13,621	9	13,630	18,605	(740)	17,865	16,723	(114)	16,609
Purchases of minerals in place	12	–	12	314	–	314	64	–	64
Extensions and discoveries	2,340	–	2,340	15,349	3,127	18,476	4,898	521	5,419
Production	(3,344)	(9)	(3,353)	(11,988)	(3,131)	(15,119)	(5,342)	(531)	(5,873)
Proved Reserves at December 31, 2009	52,440	25,502	77,942	233,039	110,242	343,281	91,280	43,876	135,156
Revisions of previous estimates	743	126	869	(12,546)	(6,373)	(18,919)	(1,348)	(936)	(2,284)
Purchases of minerals in place	1,617	–	1,617	2,990	–	2,990	2,115	–	2,115
Extensions and discoveries	–	–	–	–	824	824	–	137	137
Sales of minerals in place	(828)	–	(828)	(1,253)	–	(1,253)	(1,037)	–	(1,037)
Production	(4,464)	(7)	(4,471)	(15,899)	(3,252)	(19,151)	(7,114)	(549)	(7,663)
Proved Reserves at December 31, 2010	49,508	25,621	75,129	206,331	101,441	307,772	83,896	42,528	126,424
Revisions of previous estimates (1)	7,835	56	7,891	(62,111)	4,187	(57,924)	(2,517)	754	(1,763)
Purchases of minerals in place	1,706	–	1,706	8,913	–	8,913	3,192	–	3,192
Production	(6,107)	(4)	(6,111)	(15,095)	(2,169)	(17,264)	(8,623)	(365)	(8,988)
Proved Reserves at December 31, 2011	52,942	25,673	78,615	138,038	103,459	241,497	75,948	42,917	118,865

(1) Beginning with December 31, 2011 proved reserves, we report NGL volumes as a component of oil volumes rather than as a component of natural gas volumes and this conversion is reflected as revisions of previous estimates in 2011. Of the amounts shown, natural gas volumes decreased by 29,288 MMcf and oil and NGL volumes increased by 7,927 MBbl due to the change. The reason for the change is that, due to prevailing market prices and for the foreseeable future, we expect to be able to realize significant additional value from our natural gas streams by processing out NGLs. Additionally, natural gas volumes were revised downward by 17,292 MMcf at MC941 as one of the reservoirs on the block was found to contain more oil and less natural gas than originally estimated. Finally, natural gas volumes were revised downward by 5,833 MMcf related to unproduced volumes on our South Timbalier Block 77 property which expired in 2011.

(2) These revisions relate to our Gomez and Telemark Hubs primarily related to well performance and drilling results.

	Oil and NGL (MBbls)			Natural Gas (MMcf)			Equivalent Barrels (MBoe)		
	Gulf of Mexico	North Sea	Total	Gulf of Mexico	North Sea	Total	Gulf of Mexico	North Sea	Total
Proved Developed Reserves at									
December 31, 2009	7,826	4	7,830	44,517	12,745	57,262	15,246	2,128	17,374
December 31, 2010	13,626	4	13,630	52,656	8,323	60,979	22,402	1,391	23,793
December 31, 2011	18,590	6	18,596	46,309	5,940	52,249	26,308	996	27,304

Standardized Measure

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves for years ended December 31, is shown below (in thousands):

	Gulf of Mexico	North Sea	Total
2009			
Future cash inflows	$ 4,041,874	$ 1,965,631	$ 6,007,505
Future operating expenses	(718,854)	(353,644)	(1,072,498)
Future development costs	(891,928)	(577,080)	(1,469,008)
Future income taxes	(129,055)	(317,628)	(446,683)
Future net cash flows	2,302,037	717,279	3,019,316
10% annual discount	(778,752)	(465,857)	(1,244,609)
Standardized measure of discounted future net cash flows	$ 1,523,285	$ 251,422	$ 1,774,707
2010			
Future cash inflows	$ 4,876,858	$ 2,600,173	$ 7,477,031
Future operating expenses	(1,067,346)	(315,814)	(1,383,160)
Future development costs	(791,939)	(950,870)	(1,742,809)
Future income taxes	(158,093)	(346,104)	(504,197)
Future net cash flows	2,859,480	987,385	3,846,865
10% annual discount	(829,465)	(668,640)	(1,498,105)
Standardized measure of discounted future net cash flows	$ 2,030,015	$ 318,745	$ 2,348,760
2011			
Future cash inflows	$ 5,733,249	$ 3,675,947	$ 9,409,196
Future operating expenses	(850,090)	(350,953)	(1,201,043)
Future development costs	(581,826)	(773,226)	(1,355,052)
Future income taxes	(482,973)	(801,896)	(1,284,869)
Future net cash flows	3,818,360	1,749,872	5,568,232
10% annual discount	(1,130,327)	(906,981)	(2,037,308)
Standardized measure of discounted future net cash flows	$ 2,688,033	$ 842,891	$ 3,530,924

Future cash inflows are computed by applying average oil and gas prices to the year-end estimated future production of proved oil and gas reserves. The average prices used for this calculation are unweighted arithmetic averages of quoted market closing prices for the first day of each month, adjusted by property-specific differentials to those market prices based on product quality and transportation costs to market. Estimates of future development and operating costs are based on year-end costs and assume continuation of existing economic conditions. Estimated future income taxes are based on current laws and tax rates, projected into the future. We will incur significant capital expenditures in the development of our Gulf of Mexico and North Sea oil and gas properties. The estimated future net cash flows are then discounted using a rate of 10% per year to reflect the estimated timing of the future cash flows. The standardized measure of discounted future net cash flows is the future net cash flows less the computed discount.

The following base prices were used in determining the standardized measure as of December 31:

	Oil and NGL ($/Bbl)			Natural Gas ($/Mcf)		
	Gulf of Mexico	U.K. North Sea	Dutch North Sea	Gulf of Mexico	U.K. North Sea	Dutch North Sea
2009	61.18	59.73	50.35	3.87	4.95	8.27
2010	79.43	79.71	–	4.38	6.58	–
2011	96.16	111.26	–	4.12	9.02	–

Changes in Standardized Measure

Changes in standardized measure of future net cash flows relating to proved oil and natural gas reserves are summarized below for the years ended December 31 (in thousands):

	Gulf of Mexico	North Sea	Total
2009			
Beginning of year	$ 953,335	$ 174,747	$ 1,128,082
Sales of oil and gas, net of production costs	(208,396)	(7,047)	(215,443)
Net changes in income taxes	(98,144)	30,749	(67,395)
Net changes in price and production costs	228,126	(24,901)	203,225
Revisions of quantity estimates	368,227	(1,274)	366,953
Extensions and discoveries	105,788	11,337	117,125
Accretion of discount	95,343	32,169	127,512
Development costs incurred	359,376	68,752	428,128
Changes in estimated future development costs	(280,689)	(7,663)	(288,352)
Purchases of minerals in place	(1,639)	–	(1,639)
Changes in production rates, timing and other	1,958	(25,447)	(23,489)
	569,950	76,675	646,625
End of year	$ 1,523,285	$ 251,422	$ 1,774,707
2010			
Beginning of year	$ 1,523,285	$ 251,422	$ 1,774,707
Sales of oil and gas, net of production costs	(290,443)	(15,011)	(305,454)
Net changes in income taxes	(23,113)	(13,953)	(37,066)
Net changes in price and production costs	499,596	260,311	759,907
Revisions of quantity estimates	(40,393)	(17,872)	(58,265)
Extensions and discoveries	–	3,927	3,927
Accretion of discount	162,152	36,761	198,913
Development costs incurred	306,288	134,837	441,125
Changes in estimated future development costs	(73,339)	(171,218)	(244,557)
Purchases of minerals in place	12,714	–	12,714
Sales of minerals in place	(36,043)	–	(36,043)
Changes in production rates, timing and other	(10,689)	(150,459)	(161,148)
	506,730	67,323	574,053
End of year	$ 2,030,015	$ 318,745	$ 2,348,760
2011			
Beginning of year	$ 2,030,015	$ 318,745	$ 2,348,760
Sales of oil and gas, net of production costs	(551,392)	(13,614)	(565,006)
Net changes in income taxes	(183,028)	(235,429)	(418,457)
Net changes in price and production costs	1,110,827	335,313	1,446,140
Revisions of quantity estimates	(114,829)	19,662	(95,167)
Accretion of discount	215,137	44,889	260,026
Development costs incurred	222,727	153,509	376,236
Changes in estimated future development costs	21,384	11,430	32,814
Purchases of minerals in place	150,303	–	150,303
Changes in production rates, timing and other	(213,111)	208,386	(4,725)
	658,018	524,146	1,182,165
End of year	$ 2,688,033	$ 842,891	$ 3,530,924

Sales of oil and natural gas, net of production costs, are based on historical pre-tax results. Sales of minerals in place, extensions and discoveries, purchases of minerals-in-place and the changes due to revisions in standardized variables are reported on a pre-tax discounted basis, while the accretion of discount is presented on an after-tax basis.

SCHEDULE I – PARENT COMPANY FINANCIAL STATEMENTS

ATP OIL & GAS CORPORATION
UNCONSOLIDATED BALANCE SHEETS OF REGISTRANT
(In Thousands, Except Share Amounts)

	December 31,	
	2011	2010
Assets		
Current assets:		
Cash and cash equivalents	$ 48,106	$ 124,047
Restricted cash	4,839	–
Accounts receivable (net of allowance of $225 and $291, respectively)	64,980	69,660
Accounts receivable – intercompany	–	–
Deferred tax asset	480	8,191
Derivative asset	2,194	1,688
Other current assets	25,558	22,735
Total current assets	146,157	226,321
Oil and gas properties (using the successful efforts method of accounting):		
Proved properties	2,691,609	2,325,507
Unproved properties	10,711	9,249
	2,702,320	2,334,756
Less accumulated depletion, depreciation, impairment and amortization	(1,423,859)	(1,157,412)
Oil and gas properties, net	1,278,461	1,177,344
Deferred financing costs, net	30,732	38,897
Investment in and advance to subsidiaries	1,034,671	1,193,462
Notes receivable – intercompany	290,470	93,280
Other assets, net	12,832	12,504
Total assets	$ 2,793,323	$ 2,741,808
Liabilities and Equity		
Current liabilities:		
Accounts payable and accruals	$ 227,933	$ 176,843
Accounts payable – intercompany	12,038	3,119
Current maturities of long-term debt	2,066	1,500
Asset retirement obligation	44,577	40,472
Derivative liability	68,778	35,581
Other current liabilities	72,541	32,959
Total current liabilities	427,933	290,474
Long-term debt	1,697,966	1,639,036
Other long-term obligations	398,203	431,626
Asset retirement obligation	101,831	115,017
Deferred tax liability	480	8,191
Derivative liability	521	5,478
Deferred revenue	–	–
Total liabilities	2,626,934	2,489,822
Commitments and contingencies (Note 12, Notes to Consolidated Financial Statements in Part II, Item 8)		
Temporary equity:		
8% convertible perpetual preferred stock: $0.001 par value; 806,847 issued and outstanding at December 31, 2011; None issued and outstanding at December 31, 2010. Liquidation value of $80.7 million.	70,055	–
Shareholders' equity:		
8% convertible perpetual preferred stock: $0.001 par value, 10,000,000 shares authorized; 2,318,153 issued and outstanding at December 31, 2011; 1,400,000 issued and outstanding at December 31, 2010. Liquidation value of $231.8 million and $140.0 million at December 31, 2011 and 2010, respectively.	222,681	140,000
Common stock: $0.001 par value, 100,000,000 shares authorized; 52,034,547 issued and 51,958,707 outstanding at December 31, 2011; 51,347,163 issued and 51,271,323 outstanding at December 31, 2010	52	51
Additional paid-in capital	529,669	570,739
Accumulated deficit	(548,765)	(356,866)
Accumulated other comprehensive loss	(106,392)	(101,027)
Treasury stock, at cost	(911)	(911)
Total shareholders' equity	96,334	251,986
Total liabilities and equity	$ 2,793,323	$ 2,741,808

See notes to unconsolidated financial statements of registrant.

ATP OIL & GAS CORPORATION
UNCONSOLIDATED STATEMENTS OF OPERATIONS OF REGISTRANT
(In Thousands)

	Year Ended December 31,		
	2011	2010	2009
Revenues:			
Oil and gas production	$ 668,184	$ 416,836	$ 281,460
Other	–	–	13,664
	668,184	416,836	295,124
Costs, operating expenses and other:			
Lease operating	116,792	126,394	74,973
Processing costs – intercompany	98,059	58,031	32,937
Exploration	1,034	1,165	233
General and administrative	36,274	42,085	41,397
Depreciation, depletion and amortization	210,248	179,042	121,125
Impairment of oil and gas properties	56,400	48,392	45,799
Accretion of asset retirement obligation	12,903	12,466	10,441
Drilling interruption costs	19,691	23,647	–
Loss on abandonment	3,916	4,829	2,872
Gain on exchange/disposal of properties	(27,000)	(26,720)	(13,177)
Other, net	(2)	(948)	(743)
	528,315	468,383	315,857
Income (loss) from operations	139,869	(51,547)	(20,733)
Other income (expense):			
Interest income	–	236	16
Interest expense, net	(299,351)	(221,808)	(45,955)
Derivative income (expense)	23,372	(16,253)	(9,834)
Loss on debt extinguishment	1,095	(75,316)	–
Equity in subsidiary earnings, net of tax	(56,884)	3,116	8,660
	(331,768)	(310,025)	(47,113)
Loss before income taxes	(191,899)	(361,572)	(67,846)
Income tax (expense) benefit:			
Current	–	924	(924)
Deferred	–	23,099	19,809
	–	24,023	18,885
Net loss	(191,899)	(337,549)	(48,961)
Less convertible preferred stock dividends	(18,583)	(11,248)	(2,856)
Net loss attributable to common shareholders	$ (210,482)	$ (348,797)	$ (51,817)

See notes to unconsolidated financial statements of registrant.

ATP OIL & GAS CORPORATION
UNCONSOLIDATED STATEMENTS OF CASH FLOWS OF REGISTRANT
(In Thousands)

	Year Ended December 31, 2011	2010	2009
Net cash provided by (used in) operating activities	$ 113,648	$ (100,773)	$ 162,309
Cash flows from investing activities			
Additions to oil and gas properties	(234,861)	(534,295)	(551,555)
Proceeds from disposition of properties	27,000	17,053	13,000
Increase in restricted cash	(4,841)	–	–
Distributions from subsidiaries	109,419	218,790	144,271
Net cash used in investing activities	(103,283)	(298,452)	(394,284)
Cash flows from financing activities			
Proceeds from senior second lien notes	–	1,492,965	–
Proceeds from first lien term loans	59,400	147,000	–
Proceeds from term loans	–	46,000	19,000
Payments of term loans	(2,087)	(1,263,360)	(176,511)
Deferred financing costs	(1,561)	(53,017)	(6,490)
Loans to subsidiaries	(213,758)	(68,116)	(157,680)
Payments from subsidiary loans	16,569	16,494	146,105
Issuance of common stock, net of costs	–	–	170,629
Issuance of preferred stock, net of costs	149,866	–	135,549
Purchase of capped-call options on ATP common stock	(26,500)	–	–
Proceeds from other long-term obligations	85,326	231,888	89,011
Payments of other long-term obligations	(163,364)	(102,818)	(2,298)
Preferred stock dividends	(15,098)	(11,276)	–
Derivative contracts, net	67,129	–	–
Other financings, net	(42,433)	(11,180)	–
Exercise of stock options/warrants	205	3,609	3
Net cash provided by (used in) financing activities	(86,306)	428,189	217,318
Increase (decrease) in cash and cash equivalents	(75,941)	28,964	(14,657)
Cash and cash equivalents, beginning of year	124,047	95,083	109,740
Cash and cash equivalents, end of year	$ 48,106	$ 124,047	$ 95,083

See notes to unconsolidated financial statements of registrant.

ATP OIL & GAS CORPORATION
NOTES TO UNCONSOLIDATED FINANCIAL STATEMENTS OF REGISTRANT

Note 1 — Basis of Presentation

The financial statements of ATP Oil & Gas Corporation (the "Registrant" or "Parent Company") have been prepared pursuant to Rule 5-04 of Regulation S-X of the Securities Exchange Act of 1934, as amended, because certain of ATP's subsidiaries are contractually prohibited from making payments, loans or transferring assets to the Parent Company or other affiliated entities. Specifically, under the terms of our *ATP Titan* facility, *ATP Titan*, LLC is restricted from transferring assets or making dividends in excess of one quarter's debt service plus $10.0 million at any time. Additionally, ATP-IP is prohibited from making distributions to ATP Oil & Gas Corporation other than those specifically provided for in the Partnership Agreement. The restricted net assets associated with each of these entities exceed 25% of the consolidated net assets of ATP Oil & Gas Corporation as of December 31, 2011 and 2010.

For purposes of these financial statements, the Parent Company's investments in wholly owned subsidiaries are accounted for under the equity method. Under this method, the accounts of the subsidiaries are not consolidated. The investments in and advances to subsidiaries are recorded in the unconsolidated balance sheets. The income (loss) from operations of subsidiaries is reported on an equity basis as equity in subsidiary earnings, net of tax, in the unconsolidated statements of operations of registrant. These statements should be read in conjunction with the consolidated financial statements and notes thereto, included in Part II, Item 8 of in this Annual Report on Form 10-K.

Note 2 — Notes Receivable – Intercompany

Notes receivable – intercompany represents cumulative net advances to ATP Oil & Gas (UK) Limited and ATP Oil & Gas (Netherlands) B.V. that are subject to intercompany loan agreements (the "Notes"). The Notes provide for borrowings to each subsidiary on a revolving basis of up to $800.0 million. Outstanding balances bear interest at the same rate of interest as the principal borrowings of ATP Oil & Gas Corporation, which at December 31, 2011 was 11.875%. The Notes mature on June 27, 2018.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
FOR EACH OF THE THREE YEARS ENDED DECEMBER 31, 2011
(In Thousands)

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deduction	Balance at End of Period
2009					
Allowance for doubtful accounts	$ 352	$ 86	$ –	$ (147)	$ 291
Valuation allowance on deferred tax assets	3,025	1,300	–	–	4,325
2010					
Allowance for doubtful accounts	291	–	–	(66)	225
Valuation allowance on deferred tax assets	4,325	94,835	(99)	–	99,061
2011					
Allowance for doubtful accounts	225	–	–	–	225
Valuation allowance on deferred tax assets	99,061	62,118	(319)	–	160,860

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