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, 2000 — Commission File No. 000-32261

ATP Oil & Gas Corporation

(Exact name of registrant as specified in its charter)

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

4600 Post Oak Place, Suite 200
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

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

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 if disclosure of delinquent filers pursuant to item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this form 10-K. [X]

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant:

Voting common stock (as of March 30, 2001)	$73,045,781

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date:

As of March 30, 2001	Common Stock, par value $.001 per share	20,285,714 shares

DOCUMENTS INCORPORATED BY REFERENCE

None

ATP Oil & Gas Corporation

FORM 10-K for the Year Ended December 31, 2000

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Cautionary Statement About Forward-Looking Statements

Some of the information included in this annual report include 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. We caution that assumptions, expectations, projections, intentions and beliefs about future events may and often do vary from actual results and the differences can be material.

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;
- budgeted or projected capital expenditures;
- statements about pending or recent acquisitions, including the anticipated closing dates;
- 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 natural gas and oil markets in the United States and the United Kingdom; and
- timing and amount of future production of natural gas and oil.

When used in this document, the words "anticipate," "estimate," "project," "forecast," "may," "should," and "expect" reflect forward-looking statements.

There can be no assurance that actual results will not differ materially from those expressed or implied in such forward looking statements. Some of the key factors which could cause actual results to vary from those expected include:

- the timing and extent of changes in natural gas and oil prices;
- the timing of planned capital expenditures and availability of acquisitions;
- the inherent uncertainties in estimating proved reserves and forecasting production results;
- 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;
- the condition of the capital markets generally, which will be affected by interest rates, foreign currency fluctuations and general economic conditions;
- cost and other effects of legal and administrative proceedings, settlements, investigations and claims, including environmental liabilities which may not be covered by indemnity or insurance; and
- other U.S. or United Kingdom regulatory or legislative developments which affect the demand for natural gas or oil generally, increase the environmental compliance cost for our production wells or impose liabilities on the owners of such wells.

WHERE YOU CAN FIND MORE INFORMATION

This Annual Report on Form 10-K, including related exhibits and schedules, can be inspected and copied at the Public Reference Room maintained by the SEC at 450 Fifth Street, N.W., Washington, D.C. 20549. Copies of all or any portion of this Annual Report can be obtained after payment of fees prescribed by the SEC. You may obtain information on the operation of the Public Reference Room by calling the SEC at (800) SEC-0330. The SEC maintains a web site that contains reports, proxy and information statements and other information regarding registrants, including us, that file electronically with the SEC. The address of the site is www.sec.gov.

We are required to comply with the informational requirements of the Securities Exchange Act of 1934 and, accordingly, will file current reports on Form 8-K, quarterly reports on Form 10-Q, annual reports on Form 10-K, proxy statements and other information with the SEC. Those reports, proxy statements and other information will be available for inspection and copying at the Public Reference Room and internet site of the SEC referred to above. We intend to furnish our shareholders with annual reports containing consolidated financial statements certified by an independent public accounting firm.

PART I

Item 1. *Business*

About ATP Oil & Gas Corporation

ATP was incorporated in Texas in 1991. We are engaged in the acquisition, development and production of natural gas and oil properties in the outer continental shelf of the Gulf of Mexico, in the shallow-deep waters of the Gulf of Mexico and in the Southern Gas Basin of the U.K. North Sea. We primarily focus our efforts on natural gas and oil properties with proved undeveloped reserves that are economically attractive to us but are not strategic to major or exploration-oriented independent oil and gas companies. We attempt to achieve a high return on our investment in these properties by limiting our up-front acquisition costs and by developing our acquisitions quickly. Our management team has extensive engineering, geological, geophysical, technical and operational expertise in successfully developing and operating properties in both our current and planned areas of operation.

At December 31, 2000, we had estimated net proved reserves of 125.4 Bcfe, an increase of 20% over the previous year end. The estimated pre-tax PV-10 of our reserves at December 31, 2000 was $744.8 million. Prices used in these reserve estimates were $9.52 per MMbtu of natural gas and $23.75 per barrel of oil. At December 31, 2000, natural gas accounted for 81% of our reserves, proved developed reserves comprised 38% of our total reserves and our reserve life index for total proved reserves was 5.1 years. At December 31, 2000, we had leasehold and other interests in 47 offshore blocks, 21 platforms and 56 wells, including six subsea wells, in the federal waters of the Gulf of Mexico. We operate 53 of these 56 wells, including all of the subsea wells, and 90% of our offshore platforms. Our average working interest in our properties at December 31, 2000 was approximately 86%.

We produced approximately 24.5 Bcfe in 2000, an increase of 41% over the previous year. For the five-year period since 1996, we have increased our annual production at a compounded annual growth rate (CAGR) of 115%. We increase our reserves and production exclusively through the acquisition and development of proved natural gas and oil properties. During 2000, we replaced 187% of 2000 production through these activities, and from 1997 to 2000 we achieved an average annual reserve replacement ratio of 259%. We believe substantial additional acquisition opportunities exist in the outer continental shelf of the Gulf of Mexico, the shallow-deep waters of the Gulf of Mexico and in the Southern Gas Basin of the U.K. North Sea.

We were listed on the 2000 *Inc. 500* as the 5th fastest growing privately held company in the United States, an improvement from our ranking as 21st in the 1999 *Inc. 500*. In both 1999 and 2000, we were the fastest growing energy company in those surveys. During 2000, we received a Growing with Technology Award from Inc./Cisco for innovative utilization of technology in offshore oil and gas development. In October 2000, we were recognized as the only North American finalist in the year 2000 *Financial Times* and Deloitte Touche Tohmatsu Energy Award for Best Oil & Gas Company. Also in 2000, we received Blue Chip Enterprise recognition from MassMutual, and our company president and founder, T. Paul Bulmahn, was selected Entrepreneur Of The Year in Energy & Energy Services by Ernst & Young.

Our Business Strategy

Our business strategy is to enhance shareholder value primarily through the acquisition, development and production of proved undeveloped natural gas and oil reserves in areas that have:

- a substantial existing infrastructure and geographic proximity to well-developed markets for natural gas and oil;
- a large number of properties that major oil companies, exploration-oriented independents and others consider non-strategic; and
- a relatively stable history of consistently applied governmental regulations for offshore natural gas and oil development and production.

Prior to 2000, our area of concentration was the outer continental shelf of the Gulf of Mexico, which exhibits each of the above characteristics. In 2000, we expanded our efforts into the shallow-deep waters of the Gulf of Mexico and into the Southern Gas Basin of the U.K. North Sea, each of which we believe also exhibits these characteristics.

We believe our strategy significantly reduces the risks associated with traditional natural gas and oil exploration. Unlike oil and gas companies that conduct exploration activities, our focus is to acquire properties that have been previously explored by others and found to contain proved reserves. During the life span of these properties, they may become non-core or non-strategic to their original owners. Reasons that a property may become non-core or non-strategic are varied. For example, companies may elect to concentrate their efforts elsewhere, to reduce their capital spending for development, or to pursue exploration projects as opposed to development projects. Also, a lease expiration date may be approaching and the owner may be unwilling to complete a development program. Companies pursuing exploration success may discover hydrocarbons which may not provide an acceptable economic return for them but which may prove attractive to us. If such a project is economically attractive to us and is in our core areas, we will attempt to acquire the project. Each natural gas and oil discovery by another company in our core areas is a potential opportunity for the application of our approach.

We focus on developing projects in the shortest time possible between initial investment and first revenue generated in order to maximize our rate of return. Since we usually operate the properties in which we acquire a working interest and begin a development program with proved reserves, we are able to expeditiously commence a project's development. We typically initiate new development projects by simultaneously obtaining the various required components such as the pipeline and the production platform or subsea well completion equipment. This strategy, combined with our ability to rapidly evaluate and implement a project's requirements, allows us to complete the development project and commence production as quickly and efficiently as possible.

Our Strengths

- **Operating Efficiency.** We emphasize a low overhead and operating expense structure. For 2000, our lease operating expense was $0.47 per Mcfe of production and our general and administrative expense was $0.22 per Mcfe of production. We believe that our focus on a low cost structure allows us to pursue the acquisition, development and production of properties that may not be economically attractive to others. For the three year period ended December 31, 2000, our total average cost incurred for finding and developing our net proved reserves was $1.29 per Mcfe.
- **Operating Control.** As of December 31, 2000, we operated 90% of our offshore platforms and 100% of our subsea wells. Being an operator allows us greater control of costs, the timing and amount of capital expenditures, and the selection of completion and production technology.
- **Technical Expertise and Significant Experience.** We have assembled a management team and technical staff with an average of 17 years of industry experience. Our technical staff has specific expertise in offshore property development, including the implementation of subsea completion technology.
- **Employee Ownership.** Through employee ownership, we have built a staff whose business decisions are aligned with our shareholders. Our employees own 71% of ATP on a fully diluted basis.

Marketing and Delivery Commitments

We sell most of our natural gas and oil production under price sensitive or market price contracts. Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil. The price received by us for our non-hedged natural gas and oil production fluctuates widely. Changes in the prices of natural gas and oil will affect the carrying value of our proved reserves and our revenues, profitability and cash flow. Although we are not currently experiencing any significant involuntary curtailment of our natural gas or oil production, market, economic and regulatory factors may in the future materially affect our ability to sell our natural gas or oil production.

We sell a portion of our natural gas and oil to end users through various gas marketing companies. We are not dependent upon, or confined to, any one purchaser or small group of purchasers. Due to the nature of natural gas and oil markets and because natural gas and oil 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.

Competition

We compete with major and independent natural gas and oil 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. 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 natural gas and oil properties and may be able to define, evaluate, bid for and acquire a greater number of properties than we can. 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 and to consummate transactions in this highly competitive environment. In addition, some of our competitors have been operating in the Gulf of Mexico or in the Southern Gas Basin of the U.K. North Sea for a much longer time than we have and have demonstrated the ability to operate through a number of industry cycles.

Regulation

Federal Regulation of Sales and Transportation of Natural Gas. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and Federal Energy Regulatory Commission 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 of 1938 and Natural Gas Policy Act of 1978 price and non-price controls affecting producer sales of natural gas effective January 1, 1993. Congress could, however, re-enact price controls in the future.

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. Beginning in April 1992, the Federal Energy Regulatory Commission issued Order No. 636 and a series of related orders, which required interstate pipelines to provide open-access transportation on a not unduly discriminatory basis for all natural gas shippers. The Federal Energy Regulatory Commission has stated that it intends for Order No. 636 and its future restructuring activities to foster increased competition within all phases of the natural gas industry. Although Order No. 636 does not directly regulate our production and marketing activities, it does affect how buyers and sellers gain access to the necessary transportation facilities and how we and our competitors sell natural gas in the marketplace.

The courts have largely affirmed the significant features of Order No. 636 and the numerous related orders pertaining to individual pipelines. However, some appeals remain pending and the Federal Energy Regulatory Commission continues to review and modify its regulations regarding the transportation of natural gas. For example, the Federal Energy Regulatory Commission issued Order No. 637 which;

- lifts the cost-based cap on pipeline transportation rates in the capacity release market until September 30, 2002, for short-term releases of pipeline capacity of less than one year,
- permits pipelines to file for authority to charge different maximum cost-based rates for peak and off-peak periods,
- encourages, but does not mandate, auctions for pipeline capacity,
- requires pipelines to implement imbalance management services,

- restricts the ability of pipelines to impose penalties for imbalances, overruns and non-compliance with operational flow orders, and
- implements a number of new pipeline reporting requirements.

Order No. 637 also requires the Federal Energy Regulatory Commission Staff to analyze whether the Federal Energy Regulatory Commission should implement additional fundamental policy changes. These include whether to pursue performance-based or other non-cost based ratemaking techniques and whether the Federal Energy Regulatory Commission should mandate greater standardization in terms and conditions of service across the interstate pipeline grid.

In April 1999 the Federal Energy Regulatory Commission issued Order No. 603, which implemented new regulations governing the procedure for obtaining authorization to construct new pipeline facilities. In September 1999, the Federal Energy Regulatory Commission issued a related policy statement establishing a presumption in favor of requiring owners of new pipeline facilities to charge rates for service on new pipeline facilities based solely on the costs associated with such new pipeline facilities.

We cannot predict what further action the Federal Energy Regulatory Commission will take on these matters, nor can we accurately predict whether the Federal Energy Regulatory Commission'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, which the Federal Energy Regulatory Commission implements as to transportation and pipeline issues, requires that all pipelines operating on or across the Outer Continental Shelf provide open-access, non-discriminatory service. Historically, the Federal Energy Regulatory Commission has opted not to impose regulatory requirements under its Outer Continental Shelf Lands Act authority on gatherers and other entities outside the reach of its Natural Gas Act jurisdiction. However, the Federal Energy Regulatory Commission recently issued Order No. 639, requiring that virtually all non-proprietary pipeline transporters of natural gas on the Outer Continental Shelf report information on their affiliations, rates and conditions of service. The reporting requirements established by the Federal Energy Regulatory Commission in Order No. 639 may apply, in certain circumstances, to operators of production platforms and other facilities on the Outer Continental Shelf, with respect to gas movements across such facilities. Among the Federal Energy Regulatory Commission's stated purposes in issuing such rules was the desire to increase transparency in the market, to provide producers and shippers on the Outer Continental Shelf with greater assurance of (a) open-access services on pipelines located on the Outer Continental Shelf and (b) non-discriminatory rates and conditions of service on such pipelines.

The Federal Energy Regulatory Commission retains authority under the Outer Continental Shelf Lands Act to exercise jurisdiction over gatherers and other entities outside the reach of its Natural Gas Act jurisdiction if necessary to ensure non-discriminatory access to service on the Outer Continental Shelf. We do not believe that any Federal Energy Regulatory Commission action taken under its Outer Continental Shelf Lands Act jurisdiction will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the Federal Energy Regulatory Commission and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the Federal Energy Regulatory Commission and Congress will continue.

Federal Leases. A substantial portion of our operations is located on federal natural gas and oil leases, which are administered by the Minerals Management Service pursuant to the Outer Continental Shelf Lands Act. These leases are issued through competitive bidding and contain relatively standardized terms. These leases require compliance with detailed Minerals Management Service regulations and orders that are subject to interpretation and change by the Minerals Management Service.

For offshore operations, lessees must obtain Minerals Management Service approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency, lessees must obtain a permit from the Minerals Management Service prior to the commencement of drilling. The Minerals Management Service has promulgated regulations requiring offshore production facilities located on the Outer Continental Shelf to meet stringent engineering and construction specifications. The Minerals Management Service also has regulations restricting the flaring or venting of natural gas, and has proposed to amend such regulations to prohibit the flaring of liquid hydrocarbons and oil without prior authorization. Similarly, the Minerals Management Service has promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities.

To cover the various obligations of lessees on the Outer Continental Shelf, the Minerals Management Service generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. The cost of these bonds or assurances can be substantial, and there is no assurance that they can be obtained in all cases. We currently have several supplemental bonds in place. Under some circumstances, the Minerals Management Service may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect our financial condition and results of operations.

The Minerals Management Service also administers the collection of royalties under the terms of the Outer Continental Shelf Lands Act and the oil and gas leases issued under the Act. The amount of royalties due is based upon the terms of the oil and gas leases as well as of the regulations promulgated by the Minerals Management Service. These regulations are amended from time to time, and the amendments can affect the amount of royalties that we are obligated to pay to the Minerals Management Service. However, we do not believe that these regulations or any future amendments will affect us in a way that materially differs from the way it affects other oil and gas producers, gathers and marketers.

Oil Price Controls and Transportation Rates. Sales of crude oil, condensate and natural gas liquids by us are not currently regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to Federal Energy Regulatory Commission jurisdiction under the Interstate Commerce Act. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes.

The regulation of pipelines that transport crude oil, condensate and natural gas liquids is generally more light-handed than the Federal Energy Regulatory Commission's regulation of gas pipelines under the Natural Gas Act. Regulated pipelines that transport crude oil, condensate, and natural gas liquids are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of the Federal Energy Regulatory Commission under the Interstate Commerce Act, rates generally must be cost-based, although market-based rates or negotiated settlement rates are permitted in certain circumstances. Pursuant to Federal Energy Regulatory Commission Order No. 561, pipeline rates are subject to an indexing methodology. Under this indexing methodology, pipeline rates are subject to changes in the Producer Price Index for Finished Goods, minus one percent. A pipeline can seek to increase its rates above index levels provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can seek to charge market-based rates if it establishes that it lacks significant market power. In addition, a pipeline can establish rates pursuant to settlement if agreed upon by all current shippers. A pipeline can seek to establish initial rates for new services through a cost-of-service proceeding, a market-based rate proceeding, or through an agreement between the pipeline and at least one shipper not affiliated with the pipeline. The Federal Energy Regulatory Commission indicated in Order No. 561 that it will assess in 2000 how the rate-indexing method is operating. The Federal Energy Regulatory Commission issued a Notice of Inquiry on July 27, 2000 seeking comment on whether to retain or to change the existing index.

With respect to intrastate crude oil, condensate and natural gas liquids pipelines subject to the jurisdiction of state agencies, regulation is generally less rigorous than the regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests. Complaints or protests have been infrequent and are usually resolved informally.

We do not believe that the regulatory decisions or activities relating to interstate or intrastate crude oil, condensate, or natural gas liquids pipelines will affect us in a way that materially differs from the way it affects other crude oil, condensate, and natural gas liquids producers or marketers.

Environmental Regulations. Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Public interest in the protection of the environment has increased dramatically in recent years. Offshore drilling in some areas has been opposed by environmental groups and, in some areas, has been restricted. To the extent laws are enacted or other governmental action is taken that prohibits or restricts offshore drilling or imposes environmental protection requirements that result in increased costs to the natural gas and oil industry in general and the offshore drilling industry in particular, our business and prospects could be adversely affected.

The Oil Pollution Act of 1990 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 United States waters. 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 Oil Pollution Act of 1990 assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. 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 Oil Pollution Act of 1990.

The Oil Pollution Act of 1990 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. As amended by the Coast Guard Authorization Act of 1996, the Oil Pollution Act of 1990 requires parties responsible for offshore facilities to provide financial assurance in the amount of $35.0 million to cover potential Oil Pollution Act of 1990 liabilities. This amount can be increased up to $150.0 million if a study by the Minerals Management Service indicates that an amount higher than $35.0 million should be required. On August 11, 1998, the Minerals Management Service adopted a rule implementing these Oil Pollution Act of 1990 financial responsibility requirements. We are in compliance with this rule.

In addition, the Outer Continental Shelf Lands Act authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the Outer Continental Shelf. Specific design and operational standards may apply to Outer Continental Shelf vessels, rigs, platforms and structures. Violations of lease conditions or regulations issued pursuant to the Outer Continental Shelf Lands Act 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 Oil Pollution Act of 1990 also imposes other requirements, such as the preparation of an oil spill contingency plan. We have such a plan in place. We are also regulated by the Clean Water Act, which prohibits any discharge into waters of the United States except in strict conformance with discharge permits issued by federal or state agencies. We have obtained, and are in material compliance with, the discharge permits necessary for our operations. We could become subject to similar state and local water quality laws and regulations in the future if we conduct production or drilling activities in state coastal waters. Failure to comply with the ongoing requirements of the Clean Water Act or inadequate cooperation during a spill event may subject a responsible party to civil or criminal enforcement actions.

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 some 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. Persons who are or were responsible for releases of hazardous substances under CERCLA 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. We could be subject to liability under CERCLA because our drilling and production activities generate relatively small amounts of liquid and solid wastes that may be subject to classification as hazardous substances under CERCLA. These wastes must be brought to shore for proper disposal under the Resource Conservation and Recovery Act. We minimize this potential liability by selecting reputable contractors to dispose of our wastes at government approved landfills or other types of disposal facilities.

Our operations are also subject to regulation of air emissions under the Clean Air Act and the Outer Continental Shelf Lands Act. Implementation of these laws could lead to the gradual 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. 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 natural gas and oil development and production activities.

In addition, legislation has been proposed in Congress from time to time that would reclassify some natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If Congress were to enact this legislation, it could increase our operating costs, as well as those of the natural gas and oil industry in general. Initiatives to further regulate the disposal of natural gas and oil wastes are also pending in some states, and these various initiatives could have a similar impact on us.

Our management believes that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us.

U.K. Regulations of Natural Gas and Oil Production. Pursuant to the Petroleum Act 1998, all natural gas and oil reserves contained in properties located in Great Britain are the property of the U.K. government. The development and production of natural gas and oil reserves in the U.K. North Sea requires a petroleum production license granted by the U.K. government. Prior to developing a field, we will be required to obtain from the Secretary of State for Trade and Industry a consent to develop that field. We will also be required to obtain the consent of the Secretary of State for Trade and Industry in the event we wish to transfer an interest in a license.

The terms of the petroleum production licenses are based on model license clauses applicable at the time of the 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 for Trade and Industry the power to direct some of the licensee's activities. For example, a licensee may be precluded from carrying out development or production activities other than with the consent of the Secretary of State for Trade and Industry or in accordance with a development plan which the Secretary of State for Trade and Industry has approved. Breach of these requirements may result in the revocation of the license. In addition, licenses that we acquire may require us to pay fees and royalties on production and also impose certain other duties on us.

Our operations in the U.K. will be subject to the Petroleum Act 1998, which imposes a health and safety regime on offshore natural gas and oil production activities. The Petroleum Act 1998 also regulates the abandonment of facilities by licensees. In addition, the Mineral Workings (Offshore Installations) Act 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. Our operations will also be subject to environmental laws and regulations imposed by both the European Union and the U.K. Parliament.

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

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 access to existing pipelines or, if access is obtained, it may only be on terms that are not 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, BG Transco plc. The terms on which Transco must transport gas are governed by the Gas Acts 1986 and 1995, the gas transporter's license issued to Transco 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 Transco within the NTS. We will therefore be subject to the network code, which imposes obligations to payment, gas flow nominations, capacity booking and system imbalance. Applying for and complying with a shipper's license, and acting as a gas shipper, is expensive and administratively burdensome. Alternatively, we may sell natural gas 'at the beach' before it enters the NTS or arrange with an existing gas shipper for them to ship the gas through the NTS on our behalf.

Employees

At December 31, 2000, we had 28 full-time employees and two contract personnel in our Houston office and five full-time employees and three contract personnel in our London office. None of our employees is covered by a collective bargaining agreement. From time to time, we 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.

GLOSSARY OF TECHNICAL TERMS

Bbls. Barrels of crude oil or other liquid hydrocarbons.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one bbl of crude oil, condensate or other liquid hydrocarbons.

MMBbls. Million barrels of crude oil or other liquid hydrocarbons.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one bbl of crude oil, condensate or other liquid hydrocarbons.

Net feet of natural gas and condensate. The true vertical thickness of reservoir rock estimated to both contain hydrocarbons and be capable of contributing to producing rates.

Pre-tax PV-10. The estimated future net revenue to be generated from the production of proved reserves discounted to present value using an annual discount rate of 10%. These amounts are calculated net of estimated production costs and future development costs, using prices and costs in effect as of a certain date, without escalation and without giving effect to non-property related expenses, such as general and administrative expenses, debt service, future income tax expense, or depreciation, depletion, and amortization.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped reserves. 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. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are included only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Reserve life index. A measure of the productive life of a natural gas and oil property or a group of natural gas and oil properties, expressed in years. Reserve life equals the estimated net proved reserves attributable to a property or group of properties divided by production from the property or group of properties for the four fiscal quarters preceding the date as of which the proved reserves were estimated.

Shallow-deep waters. The waters in the Gulf of Mexico located between the continental shelf and water depths of up to approximately 3,000 feet.

Item 2. *Properties*

General

Since inception we have engaged in the acquisition, development and production of natural gas and oil properties primarily in the outer continental shelf of the Gulf of Mexico. During 2000 we entered into agreements to expand our business to include the acquisition and development of properties in the shallow-deep waters of the Gulf of Mexico and in the Southern Gas Basin of the U.K. North Sea. At December 31, 2000, we had leasehold and other interests in 47 offshore blocks, 21 platforms and 56 wells, including six subsea wells, in the federal waters of the Gulf of Mexico. We operate 53 of these 56 wells, including all of the subsea wells, and 90% of our offshore platforms. Our average working interest in our properties at December 31, 2000 was approximately 86%. As of December 31, 2000, we had leasehold interests located in the Gulf of Mexico covering approximately 177,000 gross and 157,000 net acres.

Acquisitions During 2000

Gulf of Mexico. During 2000 we acquired an interest in eleven lease blocks covering nine separate properties in the Gulf of Mexico for total acquisition costs of $7.5 million. Total proved reserves associated with these acquisitions was 65.8 Bcfe net to our interest. Our working interest in these properties range from 50% to 100%. We are the operator of all of the properties. Included in these acquisitions were four blocks on three separate properties which represent our first acquisitions in the shallow deep waters of the Gulf of Mexico. Of the six properties in the outer continental shelf, two produced during 2000 with the remainder scheduled to come on production during 2001. Two of the three properties in the shallow deep waters are scheduled to begin production in 2001. We intend to use the production and flow facilities of one of these properties, after it ceases production, to develop the third of these properties.

Southern Gas Basin of the U.K. North Sea. In October 2000, we entered into a letter of intent to acquire interests in three properties (five blocks) in the Southern Gas Basin of the U.K. North Sea. Under the letter of intent, we would acquire a 50% interest in one block, a 100% interest in one block and an 86% interest in three blocks. The letter of intent provides that we would pay an aggregate of £2,500,000, approximately $3.6 million, for the three properties at closing. We will make additional payments on a property by property basis at first production and thereafter at designated production levels. The aggregate payments at first production for all three fields would total £2,300,000, approximately $3.3 million. We do not expect first production to occur until at least 2002. The aggregate payments for achieving designated production levels for all three fields would total up to £1,650,000, approximately $2.4 million. Based on currently available information we cannot reasonably estimate when such production levels may be achieved.

Acquisitions During 2001

Gulf of Mexico. In February 2001 we acquired three properties representing 13.5 Bcfe net to our interest. In March 2001 we acquired six additional properties representing 7.8 Bcfe net to our interest. Total acquisition costs for the above acquisitions was approximately $23.0 million. Eight of the above properties were producing when acquired with additional development and production planned during 2001.

Southern Gas Basin of the U.K. North Sea. In March 2001 we acquired two of the three properties covered by the October 2000 letter of intent. Total proved reserves net to our interest in these two properties is approximately 40.0 Bcfe. Initial acquisition costs were £1.6 million, approximately $2.3 million. Neither of the properties were producing when we acquired them. We expect to begin development operations in 2001 with first production scheduled for late 2002 or early 2003. The third property remains under the letter of intent.

Natural Gas and Oil Reserves

The following table presents our estimated net proved natural gas and oil reserves and the net present value of our reserves at December 31, 2000 based on reserve reports prepared by Ryder Scott Company, L.P. and Schlumberger Holditch-Reservoir Technologies Consulting Services. The present values, discounted at 10% per annum, of estimated future net cash flows before income taxes shown in the table are not intended to represent the current market value of the estimated natural gas and oil reserves we own.

The present value of future net cash flows before income taxes as of December 31, 2000 was determined by using the December 31, 2000 prices of $9.52 per MMBtu of natural gas and $23.75 per Bbl of oil.

	Proved Reserves		
	Developed	Undeveloped	Total
Natural gas (MMcf)	42,502	59,068	101,570
Oil and condensate (MBbls)	851	3,126	3,977
Total proved reserves (MMcfe)	47,610	77,823	125,433
Pre-tax PV-10 (in thousands)	$341,903	$402,923	$744,826

Our estimates of proved reserves in the table above do not differ from those we have filed with other federal agencies. The process of estimating natural gas and oil reserves is complex. It requires various assumptions, including assumptions relating to natural gas and oil 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. Therefore, estimates of natural gas and oil reserves are inherently imprecise. Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from our estimates and these variances may be material.

You should not assume that the present value of future net cash flows referred to in this annual report is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the net present value estimate.

Our business strategy is to acquire proved reserves, usually proved undeveloped, and to bring those reserves on production as rapidly as possible. At December 31, 2000, approximately 62% of our estimated equivalent net proved reserves were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling and completion operations. The reserve data assumes that we will make these expenditures. Although we estimate our reserves and the costs associated with developing them in accordance with industry standards, the estimated costs may be inaccurate, development may not occur as scheduled and results may not be as estimated. The following table highlights our history of bringing to production our proved undeveloped reserves:

	Year Ended December 31,					
	2000		1999		1998	
	Undeveloped	Developed	Undeveloped	Developed	Undeveloped	Developed
At January 1	6	25	11	22	4	10
Acquisitions	10	1	7	1	11	8
Divestitures	—	(2)	(10)(1)	—	—	—
Undeveloped to productive	(6)	6	(2)	2	(4)	4
Undeveloped to nonproductive	—	—	—	—	—	—
At end of period	10	30	6	25	11	22

(1) Includes nine undeveloped exploration blocks that we sold. We retained a non-working future interest in seven of those blocks.

Volumes, Prices and Operating Expenses

The following table presents information regarding the production volumes of, average sales prices received for and average production costs associated with our sales of natural gas and oil for the periods indicated:

	Years Ended December 31,		
	2000	1999	1998
Production:			
Natural gas (MMcf)	22,410	16,533	9,026
Oil and condensate (MBbls)	345	128	151
Total (MMcfe)	24,477	17,301	9,933
Average sales price per unit:			
Natural gas revenues from production (per Mcf)	$ 4.20	$ 2.23	2.07
Effects of hedging activities (per Mcf)	(1.19)	(0.23)	—
Average gas price	$ 3.01	$ 2.00	$ 2.07
Oil and condensate revenues from production (per Bbl)	$29.35	$15.37	11.50
Effects of hedging activities (per Bbl)	(4.34)	—	—
Average oil price	$25.01	$15.37	$11.50
Total revenues from production (per Mcfe)	$ 4.26	$ 2.24	$ 2.05
Effects of hedging activities (per Mcfe)	(1.16)	(0.22)	—
Total average price (per Mcfe)	$ 3.10	$ 2.02	$ 2.05
Expenses (per Mcfe):			
Lease operating	$ 0.47	$ 0.32	$ 0.32
General and administrative	0.22	0.20	0.26
Depreciation, depletion and amortization—natural gas and oil properties.	1.66	1.30	1.76

Development and Acquisition Capital Expenditures

The following table presents information regarding our net costs incurred in the acquisition of proved properties and development activities (in thousands):

	Years Ended December 31,		
	2000	1999	1998
Proved property acquisition costs	$ 7,534	$25,274	$12,070
Development costs	68,982	30,777	23,866
Total costs incurred.	$76,516	$56,051	$35,936

Drilling Activity

The following table shows our drilling and completion activity. 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. We did not drill or complete any exploratory wells in any period presented.

	Years Ended December 31,					
	2000		1999		1998	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	12.0	11.0	3.0	2.2	5.0	5.0
Nonproductive	1.0	1.0	—	—	—	—
Total	13.0	12.0	3.0	2.2	5.0	5.0

As of December 31, 2000, we were conducting completion activities on 1 gross (1 net) well and drilling operations on 1 gross (1 net) well.

Productive Wells

The following table presents the number of productive natural gas and oil wells in which we owned an interest as of December 31, 2000. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

	Total Productive Wells(1)	
	Gross	Net
Natural gas	36.0	32.1
Oil	1.0	1.0
Total(1)	37.0	33.1

(1) Includes four gross and 3.2 net wells with multiple completions.

Acreage

The following table presents information regarding our developed and undeveloped acreage as of December 31, 2000.

	Developed Acreage		Undeveloped Acreage		Total	
	Gross	Net	Gross	Net	Gross	Net
Gulf of Mexico-Shelf	133,245	116,125	22,620	22,620	155,865	138,745
Gulf of Mexico-Shallow Deep Waters	—	—	20,965	18,085	20,965	18,085
Total	133,245	116,125	43,585	40,705	176,830	156,830

Item 3. ***Legal Proceedings***

From time to time, we may be a party to various legal proceedings. We currently are not a party to any material litigation.

Item 4. ***Submission of Matters to a Vote of Security Holders***

No matters were submitted to a vote of security holders during the fourth quarter of 2000.

PART II

Item 5. ***Market for Registrant's Common Equity and Related Stockholder Matters***

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 20,285,714 shares of common stock and no shares of preferred stock outstanding as of March 30, 2001. The number of record holders of our common stock as of March 28, 2001 was seven. Our common stock is traded on the Nasdaq National Market under the ticker symbol ATPG. There was no public market for our common stock before February 6, 2001. The high sales price for our common stock on the Nasdaq National Market for the period from February 6, 2001 (first trade after effective date) to March 30, 2001 was $14.563 per share and the low sales price for the same period was $9.875 per share. The closing price of our common stock on March 30, 2001 was $12.188 per share.

We have never declared or paid any 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 any 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 credit facility prohibits us from paying cash dividends on our common stock. Any future dividends may also be restricted by any loan agreements which we may enter into from time to time.

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

The selected financial data on the following pages are as of and for the years ended December 31, 2000, 1999, 1998, 1997 and 1996. The following data should be read in conjunction with "Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Company's Consolidated Financial Statements, and related notes included in "Item 8, Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

	Years Ended December 31,				
	2000	1999	1998	1997	1996 (unaudited)
	(In thousands, except share data)				
Statement of Operations Data:					
Revenues:					
Oil and gas production	$ 75,940	$ 34,981	$ 20,410	$ 7,359	$ 3,009
Gas sold—marketing	8,015	7,703	—	—	—
Gain on sale of oil and gas properties	33	287	—	304	—
Total revenues	83,988	42,971	20,410	7,663	3,009
Costs and operating expenses:					
Lease operating	11,559	5,587	3,193	1,513	308
Gas purchased—marketing	7,788	7,402	—	—	—
General and administrative	5,409	3,541	2,591	1,170	505
Depreciation, depletion and amortization	40,569	22,521	17,442	4,206	1,672
Impairment of oil and gas properties	10,838	7,509	5,072	5,787	—
Realized loss on speculative position	4,662	—	—	—	—
Unrealized loss on speculative position	7,249	—	—	—	—
Other expense	450	—	—	—	—
Total operating expenses	88,524	46,560	28,298	12,676	2,485
Net income (loss) from operations	(4,536)	(3,589)	(7,888)	(5,013)	524
Other income (expense):					
Interest income	451	202	141	207	45
Interest expense	(11,907)	(9,399)	(7,963)	(1,212)	(107)
Income (loss) before income taxes and extraordinary item	(15,992)	(12,786)	(15,710)	(6,018)	462
Income tax benefit (expense)	5,594	1,829	—	—	(1)
Income (loss) before extraordinary item	$ (10,398)	(10,957)	(15,710)	(6,018)	461
Gain on extinguishments of debt, net of tax	—	29,185	—	—	—
Net income (loss)	$ (10,398)	$ 18,228	$ (15,710)	$ (6,018)	$ 461
Weighted average number of common shares outstanding:					
Basic	14,285,714	14,285,714	11,925,785	10,567,762	8,245,513
Diluted	14,285,714	14,285,714	11,925,785	10,567,762	8,245,513
Income (loss) per common share before extraordinary item:					
Basic	$ (0.73)	$ (0.77)	$ (1.32)	$ (0.57)	$ 0.06
Diluted	$ (0.73)	$ (0.77)	$ (1.32)	$ (0.57)	$ 0.06
Net income (loss) per common share:					
Basic	$ (0.73)	1.28	$ (1.32)	$ (0.57)	$ 0.06
Diluted	$ (0.73)	$ 1.28	$ (1.32)	$ (0.57)	$ 0.06
Other Financial Data:					
Adjusted EBITDA(1)	$ 54,571	$ 26,643	$ 14,767	$ 5,187	$ 2,241
Adjusted EBITDA margin(2)	65%	62%	72%	68%	74%

	As of December 31,				
	2000	1999	1998	1997	1996 (unaudited)
Balance Sheet Data:					
Cash and cash equivalents	$ 18,136	$ 17,779	$ 3,411	$ 1,806	$ 1,088
Working capital	(3,835)	14,115	(5,106)	3,340	2,574
Net oil and gas properties	98,725	72,278	47,612	33,355	5,201
Total assets	161,993	107,054	61,354	48,906	9,074
Total long-term debt	116,529	91,723	62,690	42,194	—
Total liabilities	175,172	109,835	82,363	54,217	8,369
Shareholders' equity (deficit)	(13,179)	(2,781)	(21,009)	(5,311)	705

(1) Net income (loss) before interest expense, income taxes, depreciation, depletion and amortization, impairment of natural gas and oil properties and unrealized gains and losses. Adjusted EBITDA is not a calculation based on generally accepted accounting principles and should not be considered as an alternative to net income (loss) or operating income (loss), as an indicator of a company's financial performance or to cash flow as a measure of liquidity. In addition, our Adjusted EBITDA calculation may not be comparable to other similarly titled measures of other companies. Adjusted EBITDA is included as a supplemental disclosure because it may provide useful information regarding our ability to service debt and to fund capital expenditures.

(2) Represents Adjusted EBITDA divided by total revenues.

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

You should read the following discussion and analysis together with "Selected Financial Data" and our Financial Statements and the notes to those statements included elsewhere in this Form 10-K. This discussion contains forward-looking statements based on our current expectations, assumptions, estimates and projections about us and our industry. These forward-looking statements involve risks and uncertainties. Our actual results could differ materially from those indicated in these forward-looking statements as a result of certain factors, as more fully described under "Cautionary Statement About Forward-Looking Statements" and elsewhere in this annual report. We undertake no obligation to update publicly any forward-looking statements, even if new information becomes available or other events occur in the future.

Overview

Our results of operations reflect rapid growth in natural gas and oil production and revenues over the past three years driven primarily by our strategy of acquiring and developing properties with proved undeveloped reserves. We acquired 38 blocks from the beginning of 1998 through December 2000 and increased total proved reserves from 46.2 Bcfe at the beginning of 1998 to 125.4 Bcfe at the end of 2000, a compounded annual increase of 58% during this three-year period. We increased production from 9,933 MMcfe in 1998 to 24,477 MMcfe in 2000, a compounded annual increase of 57% for these three years. The acquisition and development of proved undeveloped natural gas and oil properties has been the primary contributor to our oil and gas revenue growth. During 2000, revenues have also reflected the positive effect of rising prices for natural gas and oil, offset in part by our hedging activity. Our revenues in future periods will reflect both our ability to continue to identify, acquire and develop properties which are consistent with our development strategy as well as commodity prices and hedging activity.

Historically, we have financed our acquisitions and development activity through a combination of borrowings and cash from operations. At December 31, 2000, we had $27.8 million outstanding under bank credit facility and $88.8 million outstanding under our development program credit agreement. In February 2001, we completed our initial public offering of 6,000,000 shares of common stock resulting in proceeds net of underwriting discount of $78.3 million. We will use the proceeds, together with cash on hand, to repay all of our outstanding debt under our development program credit agreement. Future capital requirements are expected to be met primarily through a combination of cash from operations or borrowings.

Our financial results are affected by hedging transactions we enter into with respect to natural gas and oil prices. These hedging transactions generally take the form of swaps or price collars with major financial or commodities trading institutions. Our hedging activity during 2000 and 1999 was significantly affected by the requirements of the lender under our development program credit agreement. Our hedging activity was based on expected production as required by our development program credit agreement. The details of our current hedging positions are set forth under "Item 7A, Quantitative and Qualitative Disclosures About Market Risk" below.

We have hedges in place for 69,700 MMBtu/day of natural gas for the first quarter of 2001 at an average price of $3.05 per MMBtu. We have lesser volumes hedged after the end of the first quarter of 2001. Based on actual NYMEX settlement prices for January through April of 2001 and NYMEX monthly settlement prices on March 30, 2001 for the remainder of the year, our operating income for 2001 as a result of hedging transactions would be negatively affected by approximately $22.9 million in the first quarter and a total of approximately $13.0 million in the remaining three quarters.

In addition to the above financial hedges on natural gas, during 2000 we entered into two written call option contracts that provide us a price for natural gas above the then prevailing market price, but with a ceiling price. For the period July 2000 through October 2000, we received NYMEX settlement plus $0.15 with a ceiling price of $3.16 per MMBtu on 15,000 MMBtu per day. For the period April 2001 through October 2001, we receive NYMEX settlement plus $0.15 with a ceiling price of $3.50 per MMBtu on 10,000 MMBtu per day. We recently determined that the above contracts do not qualify for hedge accounting. As a result, we have revised previously reported amounts to account for losses associated with these contracts on a mark-to-market basis. See the Supplementary Quarterly Information Schedule (unaudited) on page 61 which incorporates the losses associated with these contracts. Because the price of natural gas on March 31, 2001 was lower than the price at December 31, 2000, it is likely that we will recognize an unrealized gain for the first quarter of 2001 on the contract that expires in October 2001.

We use the successful efforts method of accounting for our investments in natural gas and oil properties. Under this method, we capitalize lease acquisition costs and intangible drilling and development costs on successful wells and development nonproductive wells. Depreciation, depletion and amortization of these capitalized costs are computed separately for each field based on the unit of production method using only proved natural gas and oil reserves.

The successful efforts method of accounting requires us to review each of our natural gas and oil properties on a field level for impairment when circumstances indicate that the capitalized costs less accumulated depreciation, depletion and amortization (also referred to as "carrying value") of the property may not be recoverable. If the carrying value of the property exceeds the expected future undiscounted cash flows, an amount equal to the excess of the carrying value over the fair value of the property is charged as an expense. An impairment results in a non-cash charge to earnings which typically does not affect cash flow. Substantial impairment writedowns may result in a reduction in our borrowing base under our bank credit facility which would require us to use additional cash to reduce debt. Since 1998, we have recorded impairments on different properties. Impairment expense totaled $10.8 million in 2000, $7.5 million in 1999 and $5.1 million in 1998.

Since September 1999, we have granted options which are currently outstanding to employees to purchase 23,752 shares of common stock at $1.40 per share and 344,822 shares of common stock at $3.85 per share. One-third of the options vest on each of April 10, 2001, February 9, 2002 and February 9, 2003. We will recognize compensation expense based on the difference between the exercise price for these options and the price of our stock offered to the public in our initial public offering. The expense will be recognized in the periods in which the options vest. Based upon the vesting schedule, we will incur a non-cash compensation expense of approximately $3.2 million in 2001 and approximately $0.6 million in 2002 relating to such option grants.

Results of Operations

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Oil and Gas Revenue. Our revenue from natural gas and oil production for 2000 increased over 1999 by 117%, from $35.0 million to $75.9 million. This increase resulted from increases of 51% in realized natural gas prices and 63% in realized oil prices as well as a 41% increase in production. The increase in production volumes from 17,301 MMcfe to 24,477 MMcfe was attributable to ten properties that were on production during 2000 that were not on production during 1999. Hedging transactions reduced oil and natural gas revenues by $28.2 million, or $1.16 per Mcfe, in 2000 and $3.8 million, or $0.22 per Mcfe, in 1999.

Marketing Revenue. During 2000, revenues from natural gas marketing activities amounted to $8.0 million, an increase of $0.3 million from 1999. The reason for the increase was a decrease in volumes offset by an increase in the sales price per MMBtu. The daily natural gas contract decreased from 9,000 MMBtu per day in 1999 to 5,000 MMBtu per day in 2000. The decrease in volume was offset by an average increase in the sales price per MMBtu from $2.34 in 1999 to $4.38 in 2000. For more information regarding this marketing activity, please read "Subsidiary Activities" below.

Lease Operating Expense. Our lease operating expense for 2000 increased 107% from $5.6 million to $11.6 million. This increase was primarily the result of an increase in the number of producing wells owned by us, an increase in their total production volume and an increase in the level of workover activity. During 1999, we held a working interest in 23 producing blocks (29 producing wells/24.7 net wells). During 2000, we held a working interest in 27 producing blocks (36 producing wells/31.6 net wells). For 1999, our net production from these wells was 16,533 MMcf and 128,000 bbls. For 2000, our net production from these wells was 22,410 MMcf and 345,000 bbls, an increase of 5,877 MMcf and 217,000 bbls. Workover spending increased from $0.4 million in 1999 to $2.6 million in 2000. The remaining increase in lease operating expense was primarily attributable to transportation related costs. On a per Mcfe basis, lease operating expense increased from $0.32 to $0.47.

Gas Purchased-Marketing. Our cost of purchased gas was $7.8 million for 2000 compared to $7.4 million for 1999. The daily gas contract amount in our third party marketing arrangement decreased from 9,000 MMBtu per day in 1999 to 5,000 MMBtu per day in 2000. Lower volumes were offset by an increase in the average gas cost from $2.25 per MMbtu in 1999 to $4.26 per MMbtu in 2000.

General and Administrative Expense. General and administrative expense increased to $5.4 million for 2000 compared to $3.5 million for 1999. The primary reason for the increase was the result of compensation and related expenses increasing from $1.8 million to $3.3 million period to period. Our total employees increased from 19 at December 31, 1999 to 33 at December 31, 2000. On an Mcfe basis, general and administrative expense was $0.22 in 2000 compared with $0.20 in 1999.

Depreciation, Depletion and Amortization Expense. Depreciation, depletion and amortization expense increased 80% during 2000 from $22.5 million to $40.6 million. The average depreciation, depletion and amortization rate was $1.66 per Mcfe during 2000 compared with $1.30 per Mcfe in 1999.

Impairment Expense. As of December 31, 2000, the future undiscounted cash flows for our properties were $931.2 million and the net book value for the properties was $109.6 million before current year impairment expense. At December 31, 1999, the future undiscounted cash flows for our properties were $183.0 and the net book value for the properties was $79.8 million before current year impairment expense. However, for three of our 33 properties in 2000 and four of our 26 properties in 1999, the future undiscounted cash flows were less than their individual net book value. As a result, we recorded impairments of $10.8 million in 2000 and $7.5 million in 1999. The impairments in 2000 and 1999 were primarily the result of a reduction in recoverable reserves individually attributable to the particular properties.

Loss on Speculative Position. For 2000 we recorded an expense of $4.3 million ($1.7 million realized and $2.6 million unrealized) on a natural gas derivative position as a result of our hedging position exceeding our expected production in an upcoming period. In this situation, we are required to account for the position using the mark-to-market method. In addition, we recorded an expense of $7.6 million ($3.0 million realized and $4.6 million unrealized) related to mark-to-market losses associated with our written call option contracts.

Other Expense. We recorded a charge of $0.5 million in 2000 relating to the sale of a platform which was held for sale and included in other assets in 1999. There was no comparable expense for this account in 1999.

Other Income (Expense). For 2000, interest expense was $11.9 million compared to $9.4 million for 1999. Our borrowings increased from period to period but were offset by a decrease in interest rates under our new development program credit agreement. As required by applicable accounting pronouncements, we capitalize interest while a property is being developed until it is ready to commence production. During 2000 we capitalized $0.7 million of interest, and we capitalized $0.6 million of interest in 1999.

Year Ended December 31, 1999 Compared to Year Ended December 31, 1998

Oil and Gas Revenue. Our revenue from natural gas and oil production for 1999 increased over 1998 revenues by 71.4%, from $20.4 million to $35.0 million primarily as a result of increased production. Natural gas production increased by 83.2% from 1998 to 1999 and realized natural gas prices fell by 3.4%. Oil production decreased by 15.3% period to period but average realized prices for oil increased by 33.7%. The increase in production volumes from 9,933 MMcfe to 17,301 MMcfe was attributable to new production resulting from development activities on four properties which began production in the second half of 1998, new production resulting from development activities on four properties that began producing in 1999, and production from producing properties acquired in the fourth quarter of 1998. Hedging transactions reduced oil and natural gas revenues by $3.8 million, or $0.22 per Mcfe, in 1999. We had no hedging transactions in 1998.

Marketing Revenue. During the year ended December 31, 1999, we recorded revenues from gas marketing activities of $7.7 million. There were no corresponding revenues for 1998. Gas marketing activities relate to the sale of 9,000 MMBtu per day to an unrelated entity. The average sales price during 1999 was $2.34 per MMBtu.

Lease Operating Expense. Our lease operating expense for 1999 increased by 75.0%, from $3.2 million to $5.6 million. The increase in expense was primarily the result of an increase in our number of producing wells and our total production volume. During 1998, we held a working interest in 22 producing blocks (27 producing wells/19.5 net wells). During 1999, we held a working interest in 23 producing blocks (29 producing wells/24.7 net wells). For 1998, our net production from these wells was 9,026 MMcf and 151,152 bbls. For 1999, our net production from these wells was 16,533 MMcf and 127,986 bbls, an increase of 7,507 MMcf and a decrease of 23,166 bbls. On a per Mcfe basis, lease operating expense remained unchanged at $0.32 per Mcfe.

Gas Purchased-Marketing. In 1999 we purchased 9,000 MMBtu per day for a total cost of $7.4 million. The average cost of purchases in 1999 was $2.25 per MMBtu. There was no corresponding expense in 1998.

General and Administrative Expense. General and administrative expense increased to $3.5 million in 1999 from $2.6 million in 1998. The primary reason for the increase was the result of compensation and related expenses increasing to $1.8 million in 1999 compared with $1.2 million in 1998. Our total number of employees increased from 11 at January 1, 1998 to 15 at December 31, 1998 and to 19 at December 31, 1999. On an Mcfe basis, general and administrative expense decreased from $0.26 during 1998 to $0.20 during 1999.

Depreciation, Depletion and Amortization Expense. Depreciation, depletion and amortization expense increased 29.1% from $17.4 million in 1998 to $22.5 million in 1999. Our average depreciation, depletion and amortization rate was $1.30 per Mcfe in 1999 and $1.76 per Mcfe in 1998. This decrease was attributable to production in 1999 from properties that required a lower relative development cost than the average cost of the producing properties in 1998.

Impairment Expense. As of December 31, 1999, the future undiscounted cash flows for our properties were $183.0 million and the net book value for the properties was $79.8 million before current year impairment expense. At December 31, 1998, the future undiscounted cash flows for our properties were $69.6 million and the net book value for the properties was $52.7 million before current year impairment expense. However, for four of our 26 properties in 1999 and four of our 20 properties in 1998, the future undiscounted cash flows were less than their individual net book value. As a result, we recorded impairments of $7.5 million in 1999 and $5.1 million in 1998. The impairments in 1998 and 1999 were primarily the result of depressed natural gas and oil prices and a reduction in recoverable reserves individually attributable to the particular properties.

Other Income (Expense). Other income (expense) consists primarily of interest income and interest expense. For the year ended December 31, 1999, interest income was $0.2 million compared to $0.1 million for the same period in 1998. This increase was primarily the result of the implementation of a new cash management system in late 1999. For 1999, interest expense was $9.4 million compared to $8.0 million for 1998. This increase was primarily the result of an increase in our non-recourse borrowings under our development program credit agreement. During 1999, we capitalized $0.6 million of interest incurred while developing properties. We capitalized $1.6 million during 1998 for the same purpose.

Extraordinary Gain. In June 1999, we agreed with the lender under a prior development program credit agreement to prepay the amount outstanding at a discount. As a result, we recorded an extraordinary gain of $29.2 million.

Liquidity and Capital Resources

We have financed our acquisition and development activity through a combination of project-based development and bank borrowing as well as cash from operations. At December 31, 2000, we had $88.8 million outstanding under our development program credit agreement and $27.8 million outstanding under our bank credit facility.

Our operating activities contributed cash flow, including changes in working capital, as follows:

Period	Cash flow from operations
1998	$13.2 million
1999	$10.8 million
2000	$56.6 million

Development Program Credit Agreement

We entered into our current development program credit agreement in April 1999. Loans outstanding under the agreement are secured only by the properties financed and are non-recourse to us, meaning that, if we default in making loan payments, the lender can seek repayment only from the properties.

From April 1999 through December 2000, we included 14 properties in this financing and obtained total funding of $118.2 million. The lender receives 90% of the monthly net revenues (after payment of operating costs) from the pledged properties. From April 1999 through December 2000, we made payments to the lender of $42.8 million, including interest, under the facility. The average interest rate was 11.5% in 1999 and 12.7% during 2000. At December 31, 2000, the amount outstanding was $88.8 million at an interest rate of 13.0%.

The lender has overriding royalty interest rights in each of the 14 properties included in the collateral base for the development program credit agreement. Ten of the 14 properties are subject to a 6.25% overriding royalty interest which begins when the full amount of outstanding under the credit agreement is repaid. The royalty interest is limited to the estimated proved reserves attributable to the properties at the time the properties were added to the collateral base less production after such date. Three of these ten properties also are subject to a 3.125% overriding royalty on certain specified levels of production above the proved reserves subject to the 6.25% interest. The lender is not entitled to either of these interests unless the full amount owed under the credit agreement has been repaid or the properties are removed from the collateral base. Four of the 14 properties included in the collateral base are subject to a 6.25% overriding royalty interest in all future production when the full amount outstanding under the credit agreement is repaid if the amounts outstanding under the credit agreement are not repaid in full prior to May 1, 2001. This 6.25% interest is not limited to any specified amount of reserves.

Since the amount of reserves attributable to these overriding royalty interests depend upon the timing of our repayment of the amounts borrowed, these overriding royalty interests are not reflected in the reserve information included in this annual report. We will repay the full amount borrowed under the development program credit agreement with the proceeds of our initial public offering and cash on hand. Based on our expected level of production for January through March 2001, our lender will receive overriding royalty interests of 1.3 Bcf in the group of ten properties described above and no interest in the other four properties when we make the final payment.

Bank Credit Agreement

In September 1998, we entered into a revolving credit facility with Chase Bank of Texas, N.A., as administrative agent. The amount available for borrowing under the facility is limited to the loan value, as determined by the bank, of certain oil and gas properties pledged under the facility. At December 31, 2000, the borrowing base was $27.8 million, all of which was outstanding. Our borrowings under the credit facility have been repaid in full as of March 30, 2001.

Advances under the credit facility can be in the form of either base rate loans or Eurodollar loans. The interest on a base rate loan is a fluctuating rate equal to the higher of the Federal funds rate plus 0.5% and the bank base rate, plus a margin of either 0.625%, 0.875%, or 1.25% depending on the amount outstanding under the credit agreement. The interest on a Eurodollar loan is equal to the Eurodollar rate quoted by Chase Bank, plus a margin of 2.375%, 2.625%, or 3.00% depending on the amount outstanding under the credit facility. The credit facility matures in January 2002. Prior to maturity, there are scheduled reductions in the amount that may be outstanding. The average per annum interest rate on borrowings under the credit facility was approximately 10.0% at December 31, 2000, 8.9% at December 31, 1999, and 8.1% at December 31, 1998.

In connection with our credit facility, we are not permitted to:

- enter into any arrangement to sell or transfer any of our material property;
- merge into or consolidate with any other person or sell or dispose of all or substantially all of our assets;
- allow the ratio of our current assets to our current liabilities to be less than 1:1 at any time.
- allow our ratio of debt to our consolidated Adjusted EBITDA for four consecutive quarters to be greater than 3 to 1.
- allow our ratio of Adjusted EBITDA for four consecutive quarters to interest payments made during those quarters to be less than 2.5 to 1.
- declare or pay any cash dividend; purchase, redeem or otherwise acquire for value any of our outstanding stock; return capital to shareholders; or make any distribution of our assets to our shareholders.

As of December 31, 2000, we were in compliance with all of the financial covenants of our credit facility other than our covenant to maintain a current ratio of at least 1:1 for which we have obtained a waiver from our lender.

Capital Expenditures

Our capital expenditures consist primarily of acquisition and development costs related to our oil and gas properties. We invested the following amounts in oil and gas properties:

Period	Investments in Oil and Gas Properties (In millions)
1998:	
Acquisition costs (5 properties)	$12.0
Development costs (6 properties)	23.9
	$35.9
1999:	
Acquisition costs (6 properties)(1)	$25.3
Development costs (14 properties)	30.8
	$56.1
2000:	
Acquisition costs (8 properties)(1)	$ 7.5
Development costs (19 properties)	69.0
	$76.5

(1) Acquisition costs include amounts paid to acquire additional working interests in properties in which we did not already own a 100% working interest.

We estimate our capital expenditure requirements on a project by project basis. At the beginning of the year, we estimate the development costs for our projects in inventory for that year. During the year as properties are acquired and scheduled for development, our actual level of capital spending may increase significantly. For example, at the beginning of 1999, we identified capital expenditures on projects then in inventory of $11.1 million. As a result of acquisition opportunities and additional development spending on newly acquired properties, our capital expenditures for the year totaled $56.1 million. At the beginning of 2000, we had identified capital expenditures of $29.0 million for development projects in inventory. As a result of current year acquisitions and additional development expenditures on newly acquired projects, at December 31, 2000, we had incurred capital expenditures of $76.5 million. Based on our inventory of properties at December 31, 2000 we had identified capital expenditures of $84.9 million for 2001 and $52.6 million in future years. Included in these capital expenditures are $0.5 million in 2001 for dismantlement, restoration and abandonment costs and $17.5 million in future years. In addition, we are constantly seeking new opportunities that fit our business strategy. Thus far in 2001 we have closed on eleven new properties for total acquisition costs of $25.3 million and have executed a letter of intent to acquire another property for an acquisition cost of approximately $1.3 million. See "Properties—Acquisitions During 2001". Our desire to continue to acquire more natural gas and oil reserves in a year than we produce will result in our incurring additional capital expenditures for properties that we acquire in the future.

We depend entirely on the acquisition and development of new properties to replace our existing reserves. Therefore, we will continue to seek opportunities for acquisitions of proved reserves with development potential. The size and timing of capital requirements for acquisitions is inherently unpredictable. Actual levels of future capital expenditures and their timing may vary significantly due to a variety of factors, including:

- drilling results;
- product prices;
- industry conditions and outlook; and
- future acquisitions of properties.

We believe that cash flow from operations and borrowings will be sufficient to fund our operations through 2001.

We believe that our capital resources are adequate to meet the requirements of our business. However, future cash flows are subject to a number of variables including the level of production and oil and natural gas prices. We cannot assure you that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures.

Subsidiary Activities

In December 1998, our wholly-owned subsidiary, ATP Energy, entered into an agreement to purchase gas over a ten-year period commencing January 1999. The amount of gas to be purchased was 9,000 MMBtu per day for the first year and 5,000 MMBtu per day for years two through ten. The contract requires ATP Energy to purchase the gas on a monthly basis at a premium to the Gas Daily Henry Hub Index. The seller is required to reimburse ATP Energy on a monthly basis for a portion of this premium during the term of the contract. The terms of the agreement provide for immediate termination upon non-performance by the seller. ATP Energy entered into a contract in December 1998 to sell an identical quantity of natural gas at the Gas Daily Henry Hub index price less $0.015 until December 2001.

ATP Energy received $6.0 million in connection with these transactions of which $2.0 million was recorded as deferred revenue and $4.0 million was recorded as deferred obligations as of December 31, 1998. The deferred revenue amount of $2.0 million is a non-refundable fee received by ATP Energy and is recognized into income as earned over the life of the contract. The deferred obligation amount of $4.0 million represented the difference between the premium we agreed to pay for natural gas under the contract and the obligation of the seller to partially reimburse us for such premium. Any deferred obligation amount not utilized is refundable if the contract is terminated. The remaining balance of the deferred obligation was $0.1 million at December 31, 2000. The premium we pay to the seller will be approximately the same as the reimbursement obligation for the remainder of the contract. ATP Energy entered into the transactions to earn the fee for agreeing to market the volumes of natural gas specified in the contract. At the end of this agreement in December 2001, we may renew the agreement or enter into another marketing arrangement having similar terms.

We formed ATP Oil & Gas (UK) Limited on May 5, 2000 to conduct our activities in the Southern Gas Basin of the U.K. North Sea. See "Item 2, Properties—Significant Acquisitions in Progress" for a description of our pending acquisitions in the U.K.

Recent Accounting Pronouncements

In June 1998, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and in June 2000, the FASB issued SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of FASB Statement No. 133*. These statements establish standards of accounting for and disclosures of derivative instruments and hedging activities. We adopted this standard on January 1, 2001. We have elected not to account for our hedging activities under the hedge accounting provisions allowed in the standard. This will result in increased earnings volatility associated with commodity price fluctuations as all of our derivative financial instruments will be accounted for on a mark-to-market basis beginning January 1, 2001. We estimate that effect of the transition adjustment, after taxes, will be a non-cash reduction of approximately $35.0 million to other comprehensive income on January 1, 2001.

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

Interest Rate Risk

We are exposed to changes in interest rates. Changes in interest rates affect the interest earned on our cash and cash equivalents and the interest rate paid on borrowings under the credit agreements. Under our current policies, we do not use interest rate derivative instruments to manage exposure to interest rate changes.

Commodity Price Risk

Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our bank credit facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas and oil that we can economically produce. We currently sell most of our natural gas and oil production under price sensitive or market price contracts. To reduce exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow, we periodically enter into hedging arrangements that usually consist of swaps or price collars that are settled in cash. However, these contracts also limit the benefits we would realize if commodity prices increase. Our internal hedging policy provides that we examine the economic effect of entering into a commodity contract with respect to the properties that we acquire. We generally acquire properties at prices that are below the value of estimated reserves at the then current natural gas and oil prices. We will enter into short term hedging arrangements if we are able to obtain commodity contracts at prices sufficient to secure an acceptable internal rate of return on a particular property or on a group of properties. As of December 31, 2000, we had no oil hedges outstanding. All of our commodity derivative financial instruments will be accounted for on a mark-to-market basis beginning January 1, 2001.

As of December 31, 2000, we had the following financial hedges on natural gas outstanding:

	SWAPS	
Period	**Average MMBtu/Day**	**Average $/MMBtu**
First quarter 2001	69,700	3.05
Second quarter 2001	29,000	2.83
Third quarter 2001	28,400	2.84
Fourth quarter 2001(1).	9,300	2.87

(1) We have no gas hedges beyond October 2001.

In addition to the above financial hedges on natural gas, during 2000 we entered into a written call option contract that provides us a price for natural gas above the then prevailing market price, but with a ceiling price. For the period April 2001 through October 2001, we receive NYMEX settlement plus $0.15 with a ceiling price of $3.50 per MMBtu on 10,000 MMBtu per day.

On occasion, we may find ourselves in speculative positions as a result of actual production being less than projected production when the derivative products were consummated or as a result of entering into speculative derivative instruments. Any speculative positions are accounted for using the mark-to-market method. Under this methodology, contracts are adjusted to market value, and the gains and losses are recognized in current period income.

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

The consolidated financial statements and supplementary data of ATP appear on pages 38 through 55 hereof and are incorporated by reference into this Item 8. Selected quarterly financial data is set forth in the Supplementary Quarterly Information Schedule on page 61, which is incorporated herein by reference.

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

None.

PART III

Item 10. *Directors and Executive Officers of Registrant*

Directors, Executive Officers and Other Key Employees

The following table sets forth the names, ages and positions of our executive officers, directors and other key employees as of March 30, 2001.

Name	Age	Position
T. Paul Bulmahn	57	Chairman, President and Director
Gerald W. Schlief	53	Senior Vice President
Albert L. Reese, Jr.	51	Senior Vice President and Chief Financial Officer
Leland E. Tate	53	Senior Vice President, Operations
John E. Tschirhart	50	Vice President, General Counsel
G. Ross Frazer	45	Vice President, Engineering
Keith R. Godwin	33	Vice President and Controller
Carol E. Overbey	49	Vice President, Corporate Secretary and Director
Arthur H. Dilly	71	Director
Gerard J. Swonke	56	Director
Robert C. Thomas	72	Director
Walter Wendlandt	71	Director

The following biographies describe the business experience of our executive officers, directors and other key employees.

T. Paul Bulmahn (BA, JD, MBA) has served as our Chairman and President since he founded the company in 1991. In 1991, he was elected Chairman, Houston Bar Association Oil, Gas and Mineral Law Section, and in 1992 was elected to serve for a three year term on the Oil & Gas Council of the State Bar of Texas. 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, Mr. Bulmahn served the Railroad Commission of Texas, the Public Utility Commission and the Interstate Commerce Commission as an administrative law judge. He has chaired various oil and gas industry seminars, including "Marginal Offshore Field Development" in 1996 and the "Upstream Oil and Gas E-Business Conference" in 2000, and has been a faculty lecturer in natural gas regulations. In June 2000, Mr. Bulmahn was selected Entrepreneur Of The Year 2000 in Energy & Energy Services by Ernst & Young LLP.

Gerald W. Schlief (BBA, CPA, MBA) has served as our Senior Vice President since 1993 and is primarily responsible for acquisitions. Between 1990 and 1993, Mr. Schlief acted as a consultant for the onshore and offshore independent oil and gas industry. From 1984 to 1990, Mr. Schlief served as Vice President, Offshore Land for Plumb Oil Company where he managed the acquisition of interests in over 35 offshore properties. From 1983 to 1984, Mr. Schlief served as Offshore Land Consultant for Huffco Petroleum Corporation. He served as Treasurer and Landman for Huthnance Energy Corporation from 1981 to 1983. In addition, from 1974 to 1978, Mr. Schlief conducted audits of oil and gas companies for Arthur Andersen & Co., and from 1978 to 1981, he conducted audits of oil and gas companies for Spicer & Oppenheim.

Albert L. Reese, Jr. (BBA, CPA, MBA) 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. He was also named Senior Vice President in August 2000. 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, cogeneration, 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.

Leland E. Tate (BS—Petroleum Engineering) has served as our Senior Vice President, Operations, since August 2000. Prior to joining ATP, Mr. Tate worked for over 30 years with Atlantic Richfield Company, a global energy company. 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., where he was responsible for all operations in the North Sea; 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, where he managed operations on the Outer Continental Shelf and deep water of the Gulf of Mexico.

John E. Tschirhart (BS—Marine Transportation, JD) joined us in November 1997 and has served as our Vice President, General Counsel since March 1998. Mr. Tschirhart was named Managing Director of ATP Oil & Gas (UK) Limited in July 2000. From 1993 to November 1997, Mr. Tschirhart worked as a partner at the law firm of Tschirhart and Daines, a partnership in Houston, Texas where he represented business clients in the energy industry. 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.

G. Ross Frazer (BS Summa Cum Laude—Nuclear Engineering) joined us in August 2000 as Vice President, Engineering. From 1993 to August 2000, he was with British-Borneo Exploration, Inc., an independent natural gas and oil company, as operations manager, engineering manager, and engineering design verification manager. This included responsibility for engineering and design verification for the deep water Gulf of Mexico Morpeth field in 1,700 feet of water and the Allegheny field in 3,300 feet of water. From 1997 to 1998, he was Chairman of the American Petroleum Institute Houston Chapter Advisory Board and presently serves on its Deep Water Operations Steering Committee.

Keith R. Godwin (BBA, CPA) has served as our Controller since May 1997 and was named a Vice President in August 2000. From 1995 to May 1997, Mr. Godwin was in private industry as Corporate Accounting Manager with Champion Healthcare Corporation, a publicly traded healthcare company. From 1990 to 1995, Mr. Godwin was employed as an accountant with the independent accounting firm of Coopers & Lybrand L.L.P. where he conducted audits primarily in the energy industry.

Carol E. Overbey (BSW, AAS—RN) has served as a director and our Corporate Secretary since 1991 and has served as Vice President since August 2000. Ms. Overbey served as our Treasurer from 1991 to 1999. From 1985 to 1991, Ms. Overbey was Vice President/Controller of Continuity Corporation. She also served in 1991 as Assistant to the President at Harbert Oil & Gas Corporation and assisted in developing gas marketing operations.

Arthur H. Dilly (BA with honors, MA) has served as a director since January 2001. From 1981 to 1998, Mr. Dilly served as Executive Secretary of the Board of Regents of the University of Texas System. He currently serves as Chairman and Chief Executive Officer of Austin Geriatrics Center, Inc., a nonprofit agency providing elderly support services, a post he has held since 1990. He has served as Vice Chairman of the Board of Directors of the Shivers Cancer Foundation, a nonprofit organization providing patient support services and education, since 1998. From 1978 to 1981, he was Executive Director for Development, The University of Texas System.

Gerard J. Swonke (BA—Economics, JD) has served as a director since 1995. Since 1985, he has been Of Counsel to the law firm of Greenberg, Peden, Siegmyer & Oshman, P.C. representing domestic and international oil and gas clients in contract drafting and negotiations, including in Indonesia, Africa and the North Sea. From

1975 to 1985 he was Counsel for Aminoil, Inc. with responsibility for onshore and offshore matters. From 1967 to 1974 when he received his law degree he was Controller for Automated Systems Corporation with responsibility for corporate accounting and preparation of financial statements and corporate tax returns.

Robert C. Thomas (BS—Geological Engineering) has served as a director since January 2001. Since 1994, Mr. Thomas has served as Chairman of the Board of The Sarkeys Energy Center of the University of Oklahoma and as a Senior Associate with Cambridge Energy Research Associates, an independent energy consulting firm. Additionally, he has served as Vice Chairman of the Gas Research Institute Advisory Council (now Gas Technology Institute), since 1998. In 1994, Mr. Thomas stepped down as Chairman and Chief Executive Officer of Tenneco Gas when he reached mandatory retirement age after thirty-eight years with Tenneco beginning in 1956. He was elected president of Tenneco Gas in 1983 and chairman and chief executive officer in 1990. He was with Tenneco's domestic exploration and production operations until 1970 when he was elected Vice President of Tenneco Oil Company's Canadian subsidiary with responsibility for all engineering, drilling, processing plant and production operations. Mr. Thomas is presently a member of the Board of Directors of Marine Drilling Companies, Inc. and PetroCorp Incorporated. He is immediate past Chairman of the Board of Directors of the YMCA of the Greater Houston Area and President of the Board of Directors of Houston Hospice. He additionally has served on the Board of Governors of The Houston Forum. Mr. Thomas has also served over 10 years on each of the following Board of Directors: The Interstate Natural Gas Association of America (INGAA), the American Gas Association (AGA), Gas Research Institute (GRI), and the Institute of Gas Technology (IGT). From 1989 to 1994 he was a member of the National Petroleum Council (NPC) and served as a Vice President of the International Association of LNG Importers (GIIGNL) headquartered in Paris.

Walter Wendlandt (BS—Mechanical Engineering, JD) has served as a director since January 2001. He was Director, Railroad Commission of Texas for a total of eighteen years during the period from 1961 to 1985. Mr. Wendlandt has been a sole practitioner of law since 1984. He served as a Trustee of the Augustana Annuity Trust from 1964 to 1992, a Director of the Georgetown Railroad from 1979 to 1982, and Director of Lamar Savings Association in 1989. He additionally has served as President, National Conference of State Transportation Specialists; Chairman, State Bar Committee on Public Utilities Law; and was a member for six years of the Technical Pipeline Safety Standards Committee of the U.S. Department of Transportation.

Board of Directors

Our board of directors currently has six members divided into three classes. The members of each class serve staggered, three-year terms. Upon the expiration of the term of a class of directors, directors in that class are elected for three-year terms at the annual meeting of shareholders in the year in which their term expires. The classes are as follows:

- Class I Directors. Mr. Bulmahn and Mr. Swonke are Class I Directors whose terms will expire at the 2004 annual meeting of shareholders;
- Class II Directors. Ms. Overbey and Mr. Wendlandt are Class II Directors whose terms will expire at the 2002 annual meeting of shareholders; and
- Class III Directors. Mr. Thomas and Mr. Dilly are Class III Directors whose terms will expire at the 2003 annual meeting of shareholders.

Committees of the Board of Directors

Our board of directors has established an audit committee and a compensation committee.

Audit Committee

The audit committee consists of Messrs. Swonke, Thomas and Wendlandt. The audit committee is responsible for:

- recommending annually to our board of directors the selection of our independent public accountants;

- reviewing and approving the scope of our independent public accountants' audit activity and the extent of non-audit services;
- reviewing with management and the independent public accountants the adequacy of our basic accounting systems and the effectiveness of our internal audit plan and activities;
- reviewing our financial statements with management and the independent public accountants and exercising general oversight of our financial reporting process; and
- reviewing our litigation and other legal matters that may affect our financial condition and monitoring compliance with our business ethics and other policies.

Compensation Committee

The compensation committee consists of Messrs. Thomas, Dilly and Swonke. This committee's responsibilities include:

- administering and granting awards under our 2000 Stock Plan;
- reviewing the compensation of our President and recommendations of the President as to appropriate compensation for our other executive officers and key personnel;
- examining periodically our general compensation structure; and
- supervising our welfare and pension plans and compensation plans.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serves as a member of the board of directors or compensation committee of any entity that has one or more of its executive officers serving as a member of our board of directors or compensation committee.

Compliance with Section 16(a) of the Securities Exchange Act

Section 16(a) of the Securities Exchange Act of 1934 (the "Exchange Act") requires our officers and directors, and persons who own more than ten percent of a registered class of our equity securities, to file reports of ownership on Form 3 and changes in ownership on Form 4 or Form 5 with the Securities and Exchange Commission (the "SEC"). Such officers, directors and ten-percent stockholders are also required by SEC rules to furnish us with copies of all Section 16(a) forms they file. During fiscal year 2000, none of our equity securities were registered under Section 12 of the Exchange Act, therefore, none of our officers, directors or holders of more than ten percent of our equity securities were required to file reports of ownership under Section 16(a) of the Exchange Act with respect to the ownership of our equity securities.

Item 11. *Executive Compensation*

The following table sets forth information regarding the compensation of our President and each of our four other most highly compensated executive officers for the year ended December 31, 2000. The annual compensation amounts in the table exclude perquisites and other personal benefits because they did not exceed the lesser of $50,000 or 10% of the total annual salary and bonus reported for each executive officer:

2000 Summary Compensation Table

Name and Principal Position	Annual Compensation		All Other Compensation(1)
	Salary	Bonus	
T. Paul Bulmahn (2) Chairman and President	$155,600	$ 85,500	$5,300
Gerald W. Schlief (2) Senior Vice President	$146,900	$ 31,400	$5,300
Albert L. Reese, Jr. Senior Vice President and Chief Financial Officer	$125,000	$123,800	$4,400
John E. Tschirhart Vice President, General Counsel	$100,000	$ 31,268	$2,700
Keith R. Godwin Vice President and Controller	$ 93,000	$ 37,200	$3,900

(1) Consists of matching contributions to our 401k savings plan.

(2) As described in "Item 13, Certain Relationships and Related Transactions," during 2000 Mr. Bulmahn and Mr. Schlief each received an overriding royalty interest in a property at the time we acquired our interest in the property. We recorded a non-cash charge of $0.3 million in connection with their receiving such interests.

Stock Options

The following table presents information concerning options granted to the named executive officers during the year ended December 31, 2000:

Name	Individual Grants				Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term(3)		
	Number of Shares Underlying Options Granted(1)	Percent of Total Options Granted to Employees in 2000	Exercise or Base Price Per Share	Expiration Date(2)	0%	5%	10%
John E. Tschirhart	35,714	9.7%	$3.85	8/1/2005	$362,497	$500,637	$667,750
Keith R. Godwin.	14,286	3.9%	$3.85	8/1/2005	$145,003	$200,260	$267,107

(1) The options were granted on August 1, 2000. Under our 1998 Stock Option Plan, one third of the options vest on each of April 10, 2001, February 9, 2002 and February 9, 2003.

(2) The expiration date is February 9, 2006.

(3) In accordance with the rules of the Securities and Exchange Commission, shown are the gains or "option spreads" that would exist for the respective options granted. These gains are based on the assumed rates of annual compound stock price appreciation of 0%, 5% and 10% from the date the option was granted over the full option term. We have assumed for these purposes that the stock price on the date of grant was equal to the initial public offering price for our shares of $14.00. These assumed annual compound rates of stock price appreciation are mandated by the rules of the Securities and Exchange Commission and do not represent our estimate or projection of our future common stock prices.

2000 Stock Plan

Our board of directors and our shareholders have adopted the 2000 Stock Plan. The purpose of the plan is to provide directors, employees and consultants of ATP and its subsidiaries additional incentive and reward opportunities designed to enhance the profitable growth of our company. The plan provides for the granting of incentive stock options intended to qualify under Section 422 of the Internal Revenue Code, options that do not constitute incentive stock options and restricted stock awards. The plan is administered by the compensation committee of our board of directors. In general, the compensation committee is authorized to select the recipients of awards and the terms and conditions of those awards.

The number of shares of common stock that may be issued under the plan will not exceed 4,000,000 shares, subject to adjustment to reflect stock dividends, stock splits, recapitalizations and similar changes in our capital structure. Shares of common stock which are attributable to awards which have expired, terminated or been canceled or forfeited are available for issuance or use in connection with future awards. The maximum number of shares of common stock that may be subject to awards granted under the plan to any one individual during the term of the plan will not exceed 50% of the aggregate number of shares that may be issued under the plan. The price at which a share of common stock may be purchased upon exercise of an option granted under the plan will be determined by the compensation committee but (a) in the case of an incentive stock option, such purchase price will not be less than the fair market value of a share of common stock on the date such option is granted, and (b) in the case of an option that does not constitute an incentive stock option, such purchase price will not be less than 50% of the fair market value of a share of common stock on the date such option is granted.

Shares of common stock that are the subject of a restricted stock award under the plan will be subject to restrictions on disposition by the holder of such award and an obligation of such holder to forfeit and surrender the shares to the under certain circumstances. The restrictions will be determined by the compensation committee in its sole discretion, and the compensation committee may provide that the restrictions will lapse upon (a) the attainment of one or more performance targets established by the compensation committee, (b) the award holder's continued employment with ATP or continued service as a consultant or director for a specified period of time, (c) the occurrence of any event or the satisfaction of any other condition specified by the compensation committee in its sole discretion or (d) a combination of any of the foregoing.

No awards under the plan may be granted after ten years from the date the plan is adopted by our board of directors. The plan will remain in effect until all awards granted under the plan have been satisfied or expired. Our board of directors in its discretion may terminate the plan at any time with respect to any shares of common stock for which awards have not been granted. The plan may be amended, other than to increase the maximum aggregate number of shares that may be issued under the plan or to change the class of individuals eligible to receive awards under the plan, by our board of directors without the consent of our shareholders. No change in any award previously granted under the plan may be made which would impair the rights of the holder of such award without the approval of the holder.

1998 Stock Option Plan

In December 1998, our board of directors and our shareholders adopted the ATP Oil & Gas Corporation 1998 Stock Option Plan. Prior to our initial public offering, the 1998 Stock Option Plan was amended to provide that the options granted under the plan will remain outstanding until their termination dates; however, no additional options will be granted.

Options granted under the plan expire on February 9, 2006. Options granted to an individual who, at the time of the grant, owned more than 10% of our common stock expire five years from the date of the grant. Each option under the 1998 Stock Option Plan may not be exercised for more than a percentage of the aggregate number of shares offered by such option in accordance with the following schedule:

Dates Exercisable	% of shares vested and exercisable
April 10, 2001	33
February 9, 2002	66
February 9, 2003	100

If there is a merger or consolidation of ATP that results in at least 40% of the outstanding voting stock of ATP (or the successor of ATP) being owned by persons or entities other than the shareholders of ATP prior to the merger or consolidation, all outstanding options will become vested and fully exercisable for the remainder of their terms. If there is a change in control other than as described in the preceding sentence, then the compensation committee may effect certain alternatives with respect to the options, including permitting exercise of the options for a limited period of time, requiring surrender of the options in exchange for cash payments, or providing for subsequent exercise for the number and class of shares of stock or other securities or property in accordance with the terms of the transaction.

401k Savings Plan

Effective March 1, 1997, we adopted a 401k savings plan. This savings and profit sharing plan covers all of our employees. The plan is subject to the provisions of the Employee Retirement Income Security Act of 1974, as amended, and Section 401(a) of the Internal Revenue Code.

The assets of the plan are held and the related investments are executed by the plan's trustee. Participants in the plan have investment alternatives in which to direct their funds and may direct their funds in one or more of these investment alternatives. We pay all administrative fees on behalf of the plan. The plan provides for discretionary matching by ATP which is currently 50% of each participant's contributions up to 6% of the participant's compensation. We contributed $56,200 for the year ended December 31, 2000, $31,000 for the year ended December 31, 1999 and $7,700 for the year ended December 31, 1998.

ATP All-Employee Bonus Program

The ATP All-Employee Bonus Program is a bonus program designed to benefit all employees based upon our overall performance. We have historically made payments to employees through the All-Employee Bonus Program on a semi-annual basis. The amount available for each employee under this program is based upon a formula that considers length of service and base compensation. Each employee is eligible to participate in the program allocations effective the first day of the month following the employee's date of employment with ATP. There are certain restrictions related to payment of an employee's allocation from the program within their first year of employment. Those payments have represented approximately 20% of average eligible compensation during the allocation period.

Compensation of Directors

Upon the closing of our initial public offering, we granted to each of our non-employee directors options to purchase 5,000 shares of common stock at an exercise price of $14.00 per share, the price paid by the public in our initial public offering, for serving as a member of our board of directors. In addition, each outside director receives $2,000 per board meeting and $500 per committee meeting attended and is reimbursed for expenses incurred. Directors who are our employees will not receive cash compensation for their services as directors or members of committees of the board.

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

The following table presents information regarding beneficial ownership of our common stock as of March 30, 2001, by:

- each person who we know owns beneficially more than 5% of our common stock;
- each of our directors;
- the persons named in our 2000 Summary Compensation Table; and
- all of our current officers and directors as a group.

Beneficial Owner	Shares Beneficially Owned	Percentage Beneficial Ownership
T. Paul Bulmahn	9,014,067	44.4%
Gerald W. Schlief	3,493,933	17.2%
Carol E. Overbey	1,164,738	5.7%
Albert L. Reese, Jr.	612,976	3.0%
John E. Tschirhart(1)	41,667	*
Keith R. Godwin(1)	14,486	*
Arthur H. Dilly(2)	5,000	*
Gerard J. Swonke(2)	5,000	*
Robert C. Thomas(2)	6,500	*
Walter Wendlandt(2)	10,000	*
All officers and directors as a group (12 persons)(3)	14,411,224	70.6%

* Represents beneficial ownership of less than 1%.

(1) Includes shares that may be acquired as of April 10, 2001 through the exercise of stock options.

(2) Includes options to purchase 5,000 shares at an exercise price of $14.00 per share, the price paid by the public in our initial public offering which we granted to our non-employee directors upon the close of our initial public offering.

(3) Includes 118,810 shares that may be acquired through the exercise of stock options.

Item 13. *Certain Relationships and Related Transactions*

In 2000, Mr. Bulmahn, Mr. Schlief and Ms. Overbey each received overriding royalty interests in one of our properties, ranging in amounts from 0.2% to 0.9%, at the time we acquired our interest in the property. In connection with their receiving these interests, we recorded non-cash charges of $0.3 million in 2000. These overriding royalty interests entitle the holder to receive a designated percentage of the net revenue during the life of the property. Our officers received these interests for their contributions to our growth during our early years and in order to align their interests with the growth in our operating revenues and cash flow. We do not expect our officers to receive such interests in the future.

We have entered into indemnification agreements with our officers and directors containing provisions requiring us to, among other things, indemnify our officers and directors against liabilities that may arise by reason of their status or service as officers or directors, other than liabilities arising from willful misconduct of a culpable nature, and to advance expenses they incur as a result of any proceeding against them as to which they could be indemnified.

PART IV

Item 14. ***Exhibits, Financial Statement Schedules and Reports on Form 8-K***

(a) Index to Financial Statements, Financial Statement Schedules and Exhibits

(1) and (2) Financial Statements and Schedules

See "Index to Consolidated Financial Statements" on page 37.

(3) Index of Exhibits

See Index of Exhibits for a list of those exhibits filed herewith, which index also includes and identifies management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(10)(iii) of Regulation S-K.

(b) Reports on Form 8-K. No reports on Form 8-K were filed during the last quarter of the period covered by this report.

(c) Index of Exhibits

Exhibit No.	Description
3.1	Amended and Restated Articles of Incorporation (incorporated by reference to Exhibit 3.1 of ATP's registration statement No. 333-46034 on Form S-1)
3.2	Restated Bylaws (incorporated by reference to Exhibit 3.2 of ATP's registration statement No. 333-46034 on Form S-1)
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 4.1 of ATP's registration statement No. 333-46034 on Form S-1)
10.1	Amended and Restated Credit Agreement, dated as of September 21, 1999, among ATP Oil & Gas Corporation, Chase Bank of Texas, National Association as Agent, and the Lenders Signatory thereto (incorporated by reference to Exhibit 10.1 of ATP's registration statement No. 333-46034 on Form S-1)
10.2	First Amendment to Amended and Restated Credit Agreement, dated as of September 21, 1999, among ATP Oil & Gas Corporation, Chase Bank of Texas, National Association, as Agent, and the Lenders Signatory thereto, effective as of June 30, 2000 (incorporated by reference to Exhibit 10.2 of ATP's registration statement No. 333-46034 on Form S-1)
10.3	Credit Agreement between ATP Oil & Gas Corporation and Aquila Energy Capital Corporation, dated April 9, 1999, effective as of March 31, 1999 (incorporated by reference to Exhibit 10.3 of ATP's registration statement No. 333-46034 on Form S-1)
10.4	First Amendment to Credit Agreement, dated April 9, 1999, by and between ATP Oil & Gas Corporation and Aquila Energy Capital Corporation (incorporated by reference to Exhibit 10.4 of ATP's registration statement No. 333-46034 on Form S-1)
10.5	Second Amendment to Credit Agreement, dated April 9, 1999, by and between ATP Oil & Gas Corporation and Aquila Energy Capital Corporation (incorporated by reference to Exhibit 10.5 of ATP's registration statement No. 333-46034 on Form S-1)

Exhibit No.	Description
10.6	Gas Service Agreement, dated December 31, 1998, between American Citigas Company and ATP Energy, Inc. (incorporated by reference to Exhibit 10.6 of ATP's registration statement No. 333-46034 on Form S-1)
10.7	Marketing & Natural Gas Purchase Agreement, dated December 1, 1998, between ATP Energy, Inc. and El Paso Energy Marketing Company (incorporated by reference to Exhibit 10.7 of ATP's registration statement No. 333-46034 on Form S-1)
10.8	Purchase and Sale Agreement, effective as of May 1, 1999, between Eugene Offshore Holdings, LLC and ATP Oil & Gas Corporation (incorporated by reference to Exhibit 10.8 of ATP's registration statement No. 333-46034 on Form S-1)
10.9	ATP Oil & Gas Corporation 1998 Stock Option Plan (incorporated by reference to Exhibit 10.9 of ATP's registration statement No. 333-46034 on Form S-1)
10.10	First Amendment to the ATP Oil & Gas Corporation 1998 Stock Option Plan (incorporated by reference to Exhibit 10.10 of ATP's registration statement No. 333-46034 on Form S-1)
10.11	ATP Oil & Gas Corporation 2000 Stock Plan
21.1	Subsidiaries of ATP Oil & Gas Corporation (incorporated by reference to Exhibit 21.1 of ATP's registration statement No. 333-46034 on Form S-1)
24.1	Power of Attorney (included on the signature page to this Registration Statement)

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

INDEPENDENT AUDITORS' REPORT

The Board of Directors
ATP Oil & Gas Corporation:

We have audited the accompanying consolidated balance sheets of ATP Oil & Gas Corporation and subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of operations, shareholders' deficit, and cash flows for each of the years in the three-year period ended December 31, 2000. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of ATP Oil & Gas Corporation and subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America.

KPMG LLP

Houston, Texas
March 31, 2001

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	December 31, 2000	December 31, 1999
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18,136	$ 17,779
Restricted cash	—	471
Accounts receivable (net of allowance for doubtful accounts)	32,542	11,119
Other current assets	2,597	1,048
Total current assets	53,275	30,417
Oil and gas properties:		
Oil and gas properties using the successful efforts method of accounting	209,548	135,609
Less accumulated depreciation, depletion, impairment and amortization	(110,823)	(63,331)
Oil and gas properties, net	98,725	72,278
Furniture and fixtures (net of accumulated depreciation)	487	250
Deferred tax assets	7,652	2,058
Other assets	1,854	2,051
Total assets	$161,993	$107,054
LIABILITIES AND SHAREHOLDERS' DEFICIT		
Current liabilities:		
Accounts payable and accruals	$ 57,047	$ 12,477
Current maturity of long-term debt	—	3,750
Other deferred obligations	63	75
Total current liabilities	57,110	16,302
Long-term debt	27,750	16,450
Non-recourse borrowings	88,779	75,273
Deferred revenue	1,481	1,667
Other deferred obligations	52	143
Total liabilities	175,172	109,835
Shareholders' deficit:		
Preferred stock: $0.001 par value, authorized 10,000,000 and none at December 31, 2000 and 1999, respectively, none issued and outstanding at December 31, 2000 and 1999	—	—
Common stock: $0.001 par value, authorized 100,000,000 and 50,000,000 shares at December 31, 2000 and 1999, respectively; issued and outstanding 14,285,714 shares at December 31, 2000 and 1999	14	14
Additional paid in capital	38	38
Accumulated deficit	(13,231)	(2,833)
Total shareholders' deficit	(13,179)	(2,781)
Commitments and contingencies		
Total liabilities and shareholders' deficit	$161,993	$107,054

See accompanying notes to the consolidated financial statements.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except share and per share data)

	Years ended December 31,		
	2000	**1999**	**1998**
Revenues:			
Oil and gas production	$ 75,940	$ 34,981	$ 20,410
Gas sold—marketing	8,015	7,703	—
Gain on sale of oil and gas properties	33	287	—
	83,988	42,971	20,410
Costs and operating expenses:			
Lease operating expenses	11,559	5,587	3,193
Gas purchased—marketing	7,788	7,402	—
General and administrative expenses	5,409	3,541	2,591
Depreciation, depletion and amortization	40,569	22,521	17,442
Impairment of oil and gas properties	10,838	7,509	5,072
Loss on speculative position	11,911	—	—
Other expense	450	—	—
	88,524	46,560	28,298
Net loss from operations	(4,536)	(3,589)	(7,888)
Other income (expense):			
Interest income	451	202	141
Interest expense	(11,907)	(9,399)	(7,963)
	(11,456)	(9,197)	(7,822)
Net loss before income taxes and extraordinary items	(15,992)	(12,786)	(15,710)
Income tax benefit	5,594	1,829	—
Loss before extraordinary item	(10,398)	(10,957)	(15,710)
Gain on extinguishment of debt, net of tax	—	29,185	—
Net income (loss)	$ (10,398)	$ 18,228	$ (15,710)
Basic and diluted earnings (loss) per common share:			
Loss before extraordinary item	$ (0.73)	$ (0.77)	$ (1.32)
Extraordinary gain, net of income taxes	—	2.05	—
Net income (loss) per common share	$ (0.73)	$ 1.28	$ (1.32)
Weighted average number of common shares:			
Basic and diluted	14,285,714	14,285,714	11,925,785

See accompanying notes to the consolidated financial statements.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' DEFICIT

Years ended December 31, 2000, 1999 and 1998

(In thousands, except share data)

	Common shares	Common share amount	Additional paid-in capital	Accumulated deficit	Total shareholders' deficit
Balance, December 31, 1997	11,069,899	$11	$28	$ (5,351)	$ (5,312)
Exercise of options	3,215,815	3	10	—	13
Net loss	—	—	—	(15,710)	(15,710)
Balance, December 31, 1998	14,285,714	14	38	(21,061)	(21,009)
Net income	—	—	—	18,228	18,228
Balance, December 31, 1999	14,285,714	14	38	(2,833)	(2,781)
Net loss	—	—	—	(10,398)	(10,398)
Balance, December 31, 2000	14,285,714	$14	$38	$(13,231)	$(13,179)

See accompanying notes to the consolidated financial statements.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years ended December 31, 2000	1999	1998
Cash flows from operating activities:			
Net income (loss)	$(10,398)	$ 18,228	$(15,710)
Adjustments to reconcile net income (loss) from operations to net cash provided by operating activities:			
Depreciation, depletion and amortization	40,569	22,521	17,442
Amortization of deferred financing costs	384	280	45
Impairment of oil and gas properties	10,838	7,509	5,072
Assignment of overrides to related party	282	557	525
Loss on speculative position	7,249	—	—
Other expense	450	—	—
Recognition of deferred revenue	(186)	(333)	—
Gain on early extinguishment of debt	—	(29,185)	—
Gain on sale of oil and gas properties	(33)	(287)	—
Change in assets and liabilities:			
(Increase) decrease in accounts receivable	(21,223)	(6,794)	7,205
Decrease in cash held in escrow	—	439	981
(Increase) in other current assets	(1,549)	(403)	(39)
Decrease in restricted cash	471	3,529	—
(Increase) in deferred tax assets	(5,594)	(2,058)	—
(Increase) in other assets	(436)	(714)	(96)
Increase (decrease) in accounts payable and accruals	35,864	1,304	(2,178)
(Decrease) in deferred obligations	(103)	(3,782)	—
Cash provided by operating activities	56,585	10,811	13,247
Cash flows from investing activities:			
Additions and acquisitions of oil and gas properties	(76,516)	(56,051)	(35,936)
Proceeds from sale of oil and gas properties	—	1,137	—
Additions to furniture and fixtures	(368)	(206)	(46)
Cash used by investing activities	(76,884)	(55,120)	(35,982)
Cash flows from financing activities:			
Increase in long-term debt	15,800	19,800	14,500
Payments of long-term debt	(8,250)	(14,100)	—
Non-recourse borrowings	42,745	93,728	20,113
Payments of non-recourse borrowings	(29,239)	(39,420)	(11,617)
Deferred financing costs incurred	(400)	(1,331)	(669)
Receipt of deferred revenue	—	—	2,000
Exercise of options to purchase common stock	—	—	13
Cash provided by financing activities	20,656	58,677	24,340
Increase in cash and cash equivalents	357	14,368	1,605
Cash and cash equivalents:			
At beginning of year	17,779	3,411	1,806
At end of year	$ 18,136	$ 17,779	$ 3,411

See accompanying notes to the consolidated financial statements.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2000, 1999 and 1998

(1) Organization

ATP Oil & Gas Corporation (ATP or the Company), a Texas corporation, was formed on August 8, 1991 and is engaged primarily in the acquisition, development and operation of oil and gas properties. ATP owns and operates its oil and gas properties utilizing financing arrangements with third parties and shared working interest arrangements. The Company operates in one business segment which is oil and gas operations.

(2) Summary of Significant Accounting Policies

General

The accompanying consolidated financial statements of the Company have been prepared according to accounting principles generally accepted in the United States of America and pursuant to the rules and regulations of the Securities and Exchange Commission. These accounting principles require the use of estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and revenues and expenses during the reporting period. Actual results could differ from those estimates. Certain reclassifications of amounts previously reported have been made to conform to current period presentations.

Basis of Presentation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries, ATP Energy, Inc. (ATP Energy) and ATP Oil & Gas (UK) Limited. All significant intercompany transactions are eliminated upon consolidation.

Cash and Cash Equivalents

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

Restricted Cash

Restricted cash primarily consist of cash on deposit and investments in money market funds and fixed income funds stated at the lower of cost or current market value.

Oil and Gas Producing Activities and Depreciation, Depletion and Amortization

The Company follows the "successful efforts" method of accounting for oil and gas properties. Under this method, lease acquisition costs and intangible drilling and development costs on successful wells and development dry holes are capitalized.

Capitalized costs relating to producing properties are depleted on the unit-of-production method. Proved developed reserves are used in computing unit rates for drilling and development costs and total proved reserves for depletion rates of leasehold, platform and pipeline costs. Estimated dismantlement, restoration and abandonment costs and estimated residual salvage values are taken into account in determining amortization and depletion provisions.

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.

The Company performs a review for impairment of proved oil and gas properties on a depletable unit basis when circumstances suggest there is a need for such a review. For properties determined to be impaired, an impairment loss equal to the differences between the carrying value and the fair value of the impaired property will be recognized. Fair value, on a depletable unit basis, is estimated to be the present value of expected future net cash flows computed by applying estimated future oil and gas prices, as determined by management, to estimated future production of oil and gas reserves over the economic lives of the reserves. Future net cash flows are based upon the Company's independent engineer's estimate 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. The Company recorded the impairments during the years ended December 31, 2000, 1999 and 1998 of $10.8 million, $7.5 million and $5.1 million, respectively, primarily due to depressed oil and natural gas prices, unfavorable operating performance and a downward revision of recoverable reserves.

Furniture and Fixtures

Furniture and fixtures consists of office furniture, computer hardware and software and leasehold improvements. Depreciation of furniture and fixtures is computed using the straight-line method over their estimated useful lives, which vary from three to ten years. Depreciation of furniture and fixtures included in depreciation, depletion and amortization expense was $131,000, $52,000 and $33,000 for the periods ended December 31, 2000, 1999 and 1998, respectively.

Capitalized Interest

The Company capitalizes interest costs associated with borrowed funds while the property in a depletable unit is being developed. The Company ceases capitalizing interest costs when the property begins its first production. Interest costs capitalized for the periods ended December 31, 2000, 1999 and 1998 and were $0.7 million, $0.6 million and $1.6 million, respectively.

Other Current Assets

Other current assets for the periods ended December 31, 2000 and 1999 include prepaid expenses of $0.3 million and $0.2 million. Prepaid expenses are amortized to production and operating expenses over the term of the related agreements. Other current assets also include estimated royalty deposits maintained with the Minerals Management Service of $2.3 million at December 31, 2000 and $0.8 million at December 31, 1999. These deposits represent an estimate of one month's payment attributable to the Minerals Management Service royalty interest in our properties.

Other Assets

Other assets include debt financing costs of $1.1 million and $1.2 million, assets held for resale of none and $0.7 million, offering costs of $0.6 million and none and spare parts inventory of $0.1 million and $0.2 million at December 31, 2000, and 1999, respectively. Debt financing costs relate to direct financing fees incurred in establishing the Company's credit facility agreements and non-recourse borrowing agreements, which are amortized to interest expense straight-line, over the term of the related agreements, which approximates the interest method. Amortization included in interest expense was $0.4 million, $0.3 million and $45,000 for the periods ended December 31, 2000, 1999 and 1998, respectively. During the year ended December 31, 2000, the Company realized a loss of $0.5 million from the sale of a platform. This amount is reflected as other expense in the statement of operations.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

December 31, 2000, 1999 and 1998

Environmental Liabilities

Environmental expenditures that relate to current or future revenues are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, and do not contribute to current or future revenue generation, are expensed. The Company has never had an environmental claim. If such a claim arose in the future, the liabilities would be recorded when environmental assessments and/or clean-ups are probable, and the costs could be reasonably estimated. Generally, the timing of these accruals coincides with the Company's commitment to a formal plan of action.

Revenue Recognition

The Company records as revenue only that portion of production sold and allocable to its ownership interest in the related property in the month the production is sold. Imbalances arise when a purchaser takes delivery of more or less volume from a property than the Company's actual interest in the production from that property. Such imbalances are reduced either by subsequent recoupment of over-and-under deliveries or by cash settlement, as required by applicable contracts. Under-deliveries are included in accounts receivable and over-deliveries are included in accounts payable. At December 31, 2000 and 1999 the Company had under-deliveries included in accounts receivable of $41,000 and none, respectively. At December 31, 2000 and 1999, the Company had over-deliveries included in accounts payable of $14,000 and $0.2 million, respectively.

The Company has allowance for doubtful accounts related to its trade accounts receivable of $0.4 million and none at December 31, 2000 and 1999.

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 attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. 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.

Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, receivables, payables and debt. The carrying amount of cash and cash equivalents, receivables and payables approximates fair value because of the short-term nature of these items.

Derivative Financial Instruments

From time to time, the Company has utilized and may continue to utilize hedging transactions with respect to a portion of its oil and gas production to achieve a more predictable cash flow as well as to reduce its exposure to price fluctuations. These transactions generally are swaps or price collars and are entered into with major financial institutions or commodities trading institutions. Derivative financial instruments are intended to reduce the Company's exposure to declines in the market price of natural gas and crude oil. These derivative financial instruments will limit the effect on the Company's realized revenues if market prices fall below the contracted floor price. As a result, gains and losses on derivative financial instruments are generally offset in the Company's oil and gas revenues by similar changes in the realized price of natural gas and crude oil.

The Company uses the hedge or deferral method of accounting for these instruments. To qualify as hedges, these instruments must highly correlate to anticipated future production such that the Company's exposure to the effects of price changes is reduced. Income and costs related to these hedging activities are recognized in oil and gas revenues when the commodities are produced. Income and costs on commodity derivative financial instruments that are closed before the hedged production occurs are also deferred until the production month originally hedged. In the event of a loss of correlation between changes in oil and gas prices under a commodity derivative financial instrument and actual oil and gas prices, income or costs are recognized currently to the extent the financial instruments had not offset changes in actual oil and gas prices.

For the years ended December 31, 2000 and 1999 the Company recorded $28.2 million and $3.8 million, respectively, as a reduction of oil and gas revenues related to hedging transactions. For the year ended December 31, 1998, the Company had no hedge transactions.

At December 31, 2000, the Company had hedged approximately 12,387 MMBtu of its expected 2001 natural gas production. The average price of hedged natural gas production is approximately $2.95 per MMBtu. The Company has no natural gas hedges in effect beyond October 2001. The Company has no oil hedges in effect beyond December 2000. All of the Company's commodity derivative financial instruments will be accounted for on a mark-to-market basis beginning January 1, 2001. See New Accounting Policies.

In addition to the above financial hedges on natural gas, during 2000 the Company entered into two written call option contracts that provide it a price for natural gas above the then prevailing market price, but with a ceiling price. For the period July 2000 through October 2000, the Company received NYMEX settlement plus $0.15 with a ceiling price of $3.16 per MMBtu on 15,000 MMBtu per day. For the period April 2001 through October 2001, the Company receives NYMEX settlement plus $0.15 with a ceiling price of $3.50 per MMBtu on 10,000 MMBtu per day.

On occasion, the Company may find itself in speculative positions as a result of actual production being less than projected production when the derivative products were consummated or as a result of entering into speculative derivative instruments. Any speculative positions are accounted for using the mark-to-market method. Under this methodology, contracts are adjusted to market value, and the gains and losses are recognized in current period income. As of December 31, 2000, the Company recognized a loss in the amount of $11.9 million from certain speculative positions. This amount is reflected as loss on speculative position in the statement of operations. At December 31, 2000, the Company has recorded $7.2 million in accounts payable and accruals related to its estimated fair value of derivative financial instruments.

Stock Options

The Company accounts for stock-based compensation using the intrinsic value method. Accordingly, compensation cost for stock options is measured as the excess, if any, of the fair value of the Company's common stock at the date of the grant over the amount an employee must pay to acquire the common stock (see note 5).

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America 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, including the use of estimates for oil and gas reserve information and the valuation allowance for deferred income taxes. Actual results could differ from those estimates.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

December 31, 2000, 1999 and 1998

Supplemental Disclosure of Cash Flow Information

For the years ended December 31, 2000, 1999, and 1998, the Company made cash payments of interest of $2.5 million, $0.6 million and $32,000, respectively. The Company made cash payments for income taxes during the years ended December 31, 2000, 1999 and 1998 of $0.5 million, none and none respectively.

Concentration of Credit Risk

Financial instruments that potentially subject the Company to concentration of credit risk consist principally of trade accounts receivable. Management believes that the credit risk posed by this concentration is offset by the creditworthiness of the Company's customer base.

Risk Factors

The Company's revenue, profitability, cash flow and future rate of growth is substantially dependent upon the price of and demand for oil and natural gas. Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and crude oil, market uncertainty and a variety of additional factors that are beyond the control of the Company. Other factors that could affect the revenue, profitability, cash flow and future growth of the Company include the Company's incurrence of losses since formation, the inherent uncertainties in reserve estimates, the concentration of production and reserves in a small number of offshore properties, the ability to finance growth, and the ability to replace reserves. The Company had a working capital surplus (deficit) at December 31, 2000 and 1999 totaling $(3.8) million and $13.7 million, respectively. The Company has historically had significant amounts of net cash used in operating and investing activities funded through short-term borrowings from financial institutions. Management believes its access to cash through future borrowings under new credit facilities and operations are sufficient to satisfy the current cash requirements. (see note 3).

New Accounting Policies

In June 1998, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and in June 2000, the FASB issued SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of FASB Statement No. 133*. These statements establish standards of accounting for and disclosures of derivative instruments and hedging activities. The Company adopted this standard on January 1, 2001. The Company has elected not to account for its hedging activities under the hedge accounting provisions allowed in the standard. This will result in increased earnings volatility associated with commodity price fluctuations as all of the Company's derivative financial instruments will be accounted for on a mark-to-market basis beginning January 1, 2001. The Company estimates that effect of the transition adjustment, after taxes, will be a non-cash reduction of approximately $35.0 million to other comprehensive income on January 1, 2001.

In March 2000, the FASB issued Interpretation No. 44, *Accounting for Certain Transactions Involving Stock Compensation: an Interpretation of APB Opinion No. 25*. Among other issues, Interpretation No. 44 clarifies the application of Accounting Principles Board Opinion No. 25 (APB No. 25) regarding (a) the definition of employee for purposes of applying APB No. 25, (b) the criteria for determining whether a plan qualifies as a non-compensatory plan, (c) the accounting consequence of various modifications to the terms of a previously fixed stock option or award, and (d) the accounting for an exchange of stock options in a business combination.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

December 31, 2000, 1999 and 1998

(3) Acquisition of Oil & Gas Properties

The Company has maintained its growth through the acquisition of proved natural gas and oil properties. Because its focus is on undeveloped properties, the Company is typically able to acquire properties with minimal cash expenditures by granting overriding royalty interests (ORRI) in those properties. The following table represents a list of our acquisitions during 2000 and 1999. For each of the acquisitions listed, the total purchase price was allocated to oil and gas properties.

Property	Working Interest Acquired	Date	Purchase Price (in thousands)
High Island A-354	100.0%	January 1999	0(a)
Vermilion 410 Field	37.5%	February 1999	5,800
East Cameron 240	100.0%	August 1999	1,500
West Cameron 492	50.0%	August 1999	1,300
Eugene Island 30	100.0%	September 1999	16,318
Vermilion 410 Field	12.5%	April 2000	951
Vermilion 260	100.0%	April 2000	125
West Cameron 635	100.0%	May 2000	1,082
Main Pass 282	100.0%	July 2000	0(a)
Garden Banks 409 (Ladybug)	50.0%	July 2000	0(a)
West Cameron 461	100.0%	November 2000	1,487
South Marsh Island 189/190	100.0%	November 2000	3,129
Garden Banks 186, 187 and 142	100.0%	November 2000	350

(a) Property was conveyed from seller who retained an overriding royalty interest.

In 2001, the Company has acquired nine properties in the Gulf of Mexico for a total acquisition cost of approximately $23.0 million. The Company has also acquired two properties in the Southern Gas Basin of the U.K. North Sea for a total acquisition cost of £1.6 million, approximately $2.3 million.

In September 1999, the Company completed an acquisition of a 100% working interest and an 82% net revenue interest in Eugene Island 30 for a purchase price of $16.3 million. The total purchase price was allocated to proved property acquisition costs. Subsequent to the acquisition, the Company became the operator of the property. The acquisition was financed through the Company's credit facility.

The following table sets forth summary unaudited pro forma financial data which is presented to give effect to the Eugene Island 30 acquisition as if the event had occurred as of January 1, 1998. The information does not purport to be indicative of actual results, as if this transaction had been in effect for the periods indicated, or of future results.

Unaudited Pro Forma Information

(Amounts in thousands except per share data)

	Years ended December 31,	
	1999	1998
Revenues	$45,242	$ 23,757
Net income (loss)	$17,978	$(15,660)
Basic and diluted earnings (loss) per share	$ 1.26	$ (1.31)

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

December 31, 2000, 1999 and 1998

(4) Long-term Debt and Non-Recourse Borrowings

Credit facility

	December 31,	
	2000	1999
	(In thousands)	
Credit facility	$27,750	$20,200
Less current portion	—	3,750
Long-term debt	$27,750	$16,450

In September 1998, the Company entered into a revolving credit facility with a national bank. The Company's maximum borrowing amount (its borrowing base) is based on the loan value, as determined by the lender, of certain oil and gas properties pledged to the credit facility. The initial borrowing base was established at $6.5 million. Several amendments from September 1998 through December 2000 adjusted the borrowing base to $27.8 million. Interest is computed either at a base rate or at the Eurodollar loan rate plus a premium (depending upon the percentage of the facility being used). Base rate loans bear interest at the higher of Federal Funds plus a premium or the bank's prime rate plus a premium. At December 31, 2000, 1999 and 1998 the average interest rate was 10.0%, 8.9% and 8.1% respectively. The credit facility is collateralized by a first mortgage on certain of the Company's oil and gas properties. Commitment fees and facility fees are paid on the unused portion of the loan. The loan agreement contains various restrictive non-financial covenants including limitations on future debt, guarantees, liens, dividends, mergers, and sale of assets. The loan agreement also contains various restrictive financial covenants including ratio of debt (exclusive of non-recourse debt and other permitted debt) to EBITDA as of the end of any fiscal quarter (calculated on a rolling four quarter basis) shall not be greater than 3.00 to 1.00, current ratio of no less than 1.0 to 1.0 at any time, and interest coverage ratio as of the end of any fiscal quarter to be less than 2.50 to 1.00. At December 31, 2000 and 1999, the Company was in compliance with all terms of the agreement other than at December 31, 2000 the covenant to maintain a current ratio of no less than 1.0 to 1.0 for which the Company obtained a waiver from the lender.

Non-Recourse Borrowing Agreements

In November 1996, the Company entered into a dollar denominated, non-recourse, production payment obligation. This obligation was subsequently supplemented in a series of amendments that occurred between that date and April 1998, in exchange for payments to the Company aggregating approximately $53.7 million plus a designated return. Of this amount, approximately $6.4 million was received in 1996, $36.6 million in 1997 and $10.7 million in 1998. These proceeds were received in exchange for the monthly obligation to provide the lender with a designated interest in the net revenues attributable to certain properties. This obligation was free of all costs of production and operation prior to the delivery point as specified in the agreement.

The payment obligations were based on the lender receiving a designated return of the Company's net revenue from the properties until such time that the sum of the net proceeds exceeded the amount advanced plus a designated return. Several amendments during the life of the agreement adjusted the percentage of net revenue allocated to repayment between 75% and 95%, the implied rate of return between 20% and 40%, and continuing interest after payout. At December 31, 1998, there was $50.7 million outstanding under this agreement.

In June 1999, the Company and the lender reached an agreement in a negotiated transaction to terminate the obligation. The Company agreed to pay in a lump sum an amount that would have been paid over the time from net revenues from certain properties. The lump sum payment was less than the amount outstanding at the date of payment. As a result, the Company recognized a gain of $29.2 million on the early extinguishments of the debt.

In April 1999, the Company entered into a second non-recourse obligation. This obligation was created in exchange for payments to the Company for up to $47.0 million. These proceeds were received in exchange for an obligation to provide the lender with 85% to 90% of the monthly net revenue received as reflected in the Company's property operating statement for certain properties as included in the agreement. In addition to the interest rate of prime plus 2½% to 3½% earned by the lender, it also has a future specified overriding royalty interest in the properties that serve as collateral.

Under the terms of this agreement, the payment obligation from the committed properties commenced during April 1999. The agreement was subsequently amended twice in 1999 to increase the amount of the lender's commitment to $91.2 million. Unless extended or further amended, the loan agreement will terminate in January 2003. At December 31, 2000 and 1999, there was $88.8 million and $75.3 million, respectively, outstanding under the agreement.

The lender has overriding royalty interest rights in each of the 14 properties included in the collateral base for the development program credit agreement. Ten of the 14 properties are subject to a 6.25% overriding royalty interest which begins when the full amount outstanding under the credit agreement is repaid. The royalty interest is limited to the estimated proved reserves attributable to the properties at the time the properties were added to the collateral base less production after such date. Three of these 10 properties also are subject to a 3.125% overriding royalty on certain specified levels of production above the proved reserves subject to the 6.25% interest. The lender is not entitled to either of these interests unless the full amount owed under the credit agreement has been repaid or the properties are removed from the collateral base. Four of the 14 properties included in the collateral base are subject to a 6.25% overriding royalty interest in all future production when the full amount outstanding under the credit agreement is repaid if the amounts outstanding under the credit agreement are not repaid in full prior to May 1, 2001. This 6.25% interest is not limited to any specified amount of reserves.

(5) Equity

Initial Public Offering

On February 5, 2001, the Company priced its initial public offering of 6 million shares of common stock and commenced trading the following day. After payment of the underwriting discount the Company received net proceeds of $78.3 million on February 9, 2001.

Change in Authorized Capitalization

On December 12, 2000, the Board of Directors approved an increase in the authorized common stock from 50,000,000 shares to 100,000,000 shares, the authorization of 10,000,000 shares of preferred stock and a 1.4-for-1 reverse split of the common stock. Par value of the common stock will remain $.001 per share. The reverse stock split was effective December 12, 2000.

The effect of the stock split has been recognized retroactively in the shareholders' equity accounts on the balance sheet as of December 31, 1999, and in all share and per share data in the accompanying consolidated financial statements, Notes to Financial Statements and supplemental financial data. Shareholders' equity accounts have been restated to reflect the reclassification of an amount equal to the par value of the decrease in issued common shares from the capital in excess of par value and retained earnings accounts to the common stock account.

Stock Options

SFAS No. 123, *Accounting for Stock-based Compensation,* defines a fair value method of accounting for an employee stock option or similar equity instrument. The Company has elected to account for its stock options using the intrinsic value method, as prescribed in Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the fair value of the Company's common stock at the date of the grant over the amount an employee must pay to acquire the common stock. Since the Company was a private company whose shares did not trade in any market, there was no established market value for the Company's common stock when options were granted. The exercise price for the stock options was determined on the basis of the formula price for stock repurchases in the Company's stockholders' agreement. Had the Company determined its compensation cost based on the fair value at the grant date for its stock options under the provisions of SFAS No. 123, the Company's pro forma net loss and profit for the years ended December 31, 2000, 1999 and 1998 would have been unchanged as the options do not vest and are not exercisable until at least 60 days after an IPO or a corporate change in control as defined by the 1998 Stock Option Plan.

1998 Stock Option Plan

In December 1998, the Board of Directors approved the 1998 Stock Option Plan (the 1998 SOP) to provide increased incentive for its employees and directors. The 1998 SOP is administered by the Compensation Committee of the Company's Board of Directors and provides for up to 2,678,571 shares of common stock to be granted to eligible participants. The stock options became exercisable upon the closing of the initial public offering of Company Stock on February 9, 2001. These options expire five years after the date of the IPO. Each option under the 1998 SOP may be exercised at any time after the grant in accordance with the following schedule:

Dates Exercisable	% of shares vested and exercisable
April 10, 2001	33
February 9, 2002	66
February 9, 2003	100

During the periods ended December 31, 2000, 1999 and 1998, the Company granted options exercisable for 23,393, 18,571 and 440,714 shares of common stock at $1.40 per share. During the period ended December 31, 2000, the Company granted options exercisable for 344,822 shares of common stock at $3.85 per share.

The Company will recognize compensation expense following its IPO based on the difference between the exercise price for options granted since September 1999 and the fair market value of its stock as determined by the IPO price of $14.00 per share. The expense will be recognized in the periods in which the options vest. Each option is divided into three equal portions corresponding to the three vesting dates, with the related compensation cost amortized straight-line over the period between the IPO date and the vesting date. Based upon the vesting schedule, the Company will incur a non-cash compensation expense of approximately $3.2 million in 2001 and approximately $0.6 million in 2002 relating to such option grants.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

December 31, 2000, 1999 and 1998

Information regarding the Company's 1998 SOP is summarized as follows:

	2000 Shares	2000 Weighted average exercise price	1999 Shares	1999 Weighted average exercise price	1998 Shares	1998 Weighted average exercise price
Outstanding at beginning of year	456,964	$1.40	440,714	$1.40	—	
Granted	368,215	$3.69	18,571	$1.40	440,714	$1.40
Expired unexercised	(178,572)	$1.40	(2,321)	$1.40	—	—
Exercised	—	—	—	—	—	—
Outstanding at end of period	646,607	$2.71	456,964	$1.40	440,714	$1.40
Exercisable at end of period	—	—	—	—	—	—
Option Grant Price	368,215	$3.69	18,571	$1.40	440,714	$1.40

1994 Stock Option Plan

In May 1994, the Board of Directors approved the 1994 Stock Option Plan (the 1994 SOP) under which it was authorized to issue up to 55,902,930 shares of common stock. The exercise price of the options under the 1994 SOP shall not be less than the greater of par value per share or fair market value, at date of grant. These options have a maximum term of 10 years, subject to vesting requirements in the individual option agreements. During 1994, options to purchase 26,235,244 shares were issued at $0.00358 per share immediately exercisable after grant. As of December 31, 2000, 1999 and 1998, options to purchase 18,937,397 shares of the 1994 options remain unexercised and outstanding. In April 2000, the only outstanding option to purchase 18,937,397 shares under the 1994 SOP was amended to limit the number of shares that could be purchased pursuant to the option to such number that enables the holder to maintain ownership of a majority of the outstanding shares. Because the holder of this option owned, and continues to own, a majority of the shares, the number of shares exercisable as of April 2000 was zero. Prior to the closing of the IPO, the 1994 Stock Option Plan and all outstanding options under the Plan were cancelled.

Information regarding the Company's 1994 SOP is summarized as follows:

	2000 Shares	2000 Weighted average exercise price	1999 Shares	1999 Weighted average exercise price	1998 Shares	1998 Weighted average exercise price
Outstanding at beginning of year	18,937,397	$0.004	18,937,397	$0.004	22,153,213	$0.004
Granted	—	—	—	—	—	—
Expired unexercised	—	—	—	—	—	—
Exercised	—	—	—	—	(3,215,816)	0.004
Outstanding at end of period	18,937,397	$0.004	18,937,397	$0.004	18,937,397	$0.004
Exercisable at end of period	—	—	18,937,397	$0.004	18,937,397	$0.004
Fair value of options granted	—	—	—	—	—	—

(6) Earnings Per Share

Basic earnings per share is computed by dividing net income (loss) available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined on the assumption that outstanding stock options have been converted using the average price for the period. For purposes of computing earnings per share in a loss year, potential common shares have been excluded from the computation of weighted average common shares outstanding because their effect is antidilutive.

Basic and diluted net income (loss) per share is computed based on the following information (in thousands, except share and per share amounts):

	For the years ended December 31,		
	2000	1999	1998
Net income (loss) available to common shareholders	$ (10,398)	$ 18,228	$ (15,710)
Basic—weighted average shares	14,285,714	14,285,714	11,925,785
Diluted—weighted average shares	14,285,714	14,285,714	11,925,785
Net income (loss) per share:			
Basic:			
Net loss before extraordinary item	$ (0.73)	$ (0.77)	$ (1.32)
Extraordinary gain, net of income taxes	—	2.05	—
Net income (loss) per common share	$ (0.73)	$ 1.28	$ (1.32)
Diluted:			
Net loss before extraordinary item	$ (0.73)	$ (0.77)	$ (1.32)
Extraordinary gain, net of income taxes	$ —	2.05	—
Net income (loss) per common share	$ (0.73)	$ 1.28	$ (1.32)

Major Customers

The Company sells a portion of its oil and gas to end users through various gas marketing companies. Three companies purchased oil and gas from the company in excess of 10% of gross oil and gas revenues before giving effect to hedging in each respective period. One of these company's purchases totaled $4.6 million and $12.4 million or 12% and 61% and for the periods ended December 31, 1999 and 1998 respectively. A second company's purchases totaled $42.7 million and $18.6 million or 41% and 48% for the periods ended December 31, 2000 and 1999 respectively. The third company's purchases totaled $42.4 million and $7.3 million or 41% and 19% for the periods ended December 31, 2000 and 1999 respectively.

(7) Income Taxes

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

	Years ended December 31,		
	2000	1999	1998
Before any valuation allowance:			
Statutory federal income tax rate	(35.00)%	35.00 %	(35.00)%
State income taxes, net of federal benefit	0.00	0.32	(0.32)
Adjustment to valuation allowance	0.00	(46.53)	35.31
Nondeductible and other	0.02	0.05	0.01
	(34.98)%	(11.16)%	0.00%

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

December 31, 2000, 1999 and 1998

At December 31, 1998, the Company had determined that it was more likely than not the deferred tax assets would not be realized. During 1998, the valuation allowance increased by $5.5 million. At December 31, 1999, however, the Company determined that it was more likely than not the deferred tax assets would be realized based on current projections of taxable income due to higher commodity prices at year-end and the valuation allowance was decreased to zero.

Significant components of the Company's deferred tax assets (liabilities) as of December 31, 2000 and 1999 are as follows (in thousands):

	December 31,	
	2000	1999
Deferred tax assets (liabilities):		
Net operating loss carryforwards	$3,826	$ 3,800
Minimum tax credit carryforwards	229	229
Fixed asset basis differences	554	(2,379)
State taxes	17	17
Unrealized book losses	2,537	—
Other	489	391
Total deferred tax assets	7,652	2,058
Valuation allowance for deferred tax assets	—	—
Net deferred tax assets	$7,652	$ 2,058

At December 31, 2000, 1999 and 1998 the Company had net operating loss carryforwards for federal income tax purposes of approximately $11 million, $11 million, and $22 million respectively, which are available to offset future federal taxable income through 2019.

(8) Commitments and Contingencies

From time to time, the Company may be a party to various legal proceedings. We currently are not a party to any material litigation.

In October 2000, we entered into a letter of intent to acquire interests in three properties (five blocks) in the Southern Gas Basin of the U.K. North Sea, two of which we have since acquired. Under the letter of intent, we would acquire a 50% interest in one block, a 100% interest in one block and an 86% interest in three blocks. The letter of intent provides that we would pay an aggregate of £2,500,000, approximately $3.6 million, for the three properties at closing. We will make additional payments on a property by property basis at first production and thereafter at designated production levels. The aggregate payments at first production for all three fields would total £2,300,000, approximately $3.3 million. We do not expect first production to occur until at least 2002. The aggregate payments for achieving designated production levels for all three fields would total up to £1,650,000, approximately $2.4 million. Based on currently available information we cannot estimate when such production levels may be achieved.

In March 2001 we acquired two of the three properties covered by the October 2000 letter of intent. Total proved reserves net to our interest in these two properties is approximately 40.0 Bcfe. Initial acquisition costs were £1.6 million, approximately $2.3 million. Neither of the properties were producing when we acquired them. We expect to begin development operations in 2001 with first production scheduled for late 2002 or early 2003. The third property remains under the letter of intent.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

December 31, 2000, 1999 and 1998

The Company has commitments under an operating lease agreement for office space. Total rent expense for the year ended December 31, 2000, 1999 and 1998 was approximately $0.2 million, $0.1 million and $0.1 million respectively. At December 31, 2000, the future minimum rental payments due under the lease are as follows (in thousands amounts):

2001	$234
2002	226
2003	230
2004	230
2005 and beyond	71
Total	$991

(9) ATP Energy Gas Purchase Transaction

ATP Energy entered an agreement in December 1998 with American Citigas Company to purchase gas over a ten-year period commencing January 1999. The amount of gas to be purchased was 9,000 MMBtu per day for the first year and 5,000 MMBtu per day for years two through ten. The contract requires ATP Energy to purchase on a monthly basis the gas at a premium of approximately $2.50 per MMBtu to the *Gas Daily* Henry Hub Index. American Citigas Company is required to reimburse ATP Energy on a monthly basis for a portion of this premium during the term of the contract. This portion of the reimbursement is accomplished by a note receivable in favor of the Company. The note receivable bears interest at 6% and has monthly payments of $373,000 commencing January 1999 and ending January 2009. The balance of the note receivable at December 31, 2000 was $28.8 million. At December 31, 2000, the present value of the remaining premium payments to be made by ATP Energy, using a discount rate of 6%, was $28.7 million. The note receivable and the premium payable to American Citigas have been offset in the consolidated financial statements in accordance with the prescribed accounting in Financial Accounting Standards Board Interpretation No. 39. The aggregate amount of premium payments to be paid by ATP Energy over the term of the contract is approximately $49.0 million and the aggregate amount of payments to be paid to ATP Energy over the term of the note is approximately $45.0 million. At December 31, 2000, the remaining premium to be paid was $ million which will be reimbursed by the monthly reimbursement from American Citigas and the remaining deferred obligation discussed below. The terms provide for the immediate termination of the agreement upon non-performance by American Citigas. ATP Energy entered into a contract with El Paso Energy Marketing in December 1998 to sell an identical quantity of natural gas at the *Gas Daily* Henry Hub index price less $0.015 until December 2001.

ATP Energy received $6.0 million in connection with these transactions, of which $2.0 million was recorded as deferred revenue and $4.0 million was recorded as deferred obligations as of December 31, 1998. The deferred revenue amount of $2.0 million is a non-refundable fee received by ATP Energy and is recognized into income as earned over the life of the contract. At December 31, 2000 and 1999 the deferred revenue amount was $1.5 million and $1.7 million, respectively. The deferred obligation amount of $4.0 million represented the difference between the premium we agreed to pay for natural gas under the American Citigas contract and the obligation of American Citigas to partially reimburse us for such premium. Any deferred obligation amount not utilized is refundable if the contract is terminated. The transaction is structured with American Citigas such that there is no financial impact to ATP Energy associated with the premium paid and reimbursement received other than the $2.0 million realized by ATP Energy. The remaining balance of the deferred obligation was $0.1 million and $0.2 million at December 31, 2000 and 1999, respectively. The premium we pay to American Citigas will be approximately the same as the reimbursement obligation for the remainder of the contract. ATP Energy entered into the transactions to earn the fee for agreeing to market the volumes of natural gas specified in the American Citigas contract. At the end of its agreement with El Paso in December 2001 the Company may renew the agreement or enter into another marketing arrangement having similar terms.

Officers of the Company were paid $152,125 and $97,875 for the periods ended December 31, 2000 and 1999, respectively, for negotiating and monitoring ATP Energy's gas supply contract. The Company has recognized these amounts in general and administrative expense in the respective periods. The Company does not intend to pay any further bonuses in connection with this transaction.

(10) Related Party Transactions

The Company has granted to certain officers of the Company overriding royalty interests ranging in amounts from 0.2% to 3.0% in four of its oil and gas properties. The overriding royalty interest entitles the holder to a portion, 0.2% to 3.0%, of the future revenue for the life of each property. As a result, the Company has recognized $0.3 million, $0.6 million and $0.5 million in general and administrative expense for the periods ended December 31, 2000, 1999 and 1998.

ATP OIL & GAS CORPORATION

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES

(Unaudited)

The following tables set forth certain historical costs and operating information related to the Company's natural gas and oil producing activities as of and for the periods ended December 31, 2000, 1999 and 1998.

Costs Incurred

Costs incurred in natural gas and oil property acquisition, exploration and development activities are summarized below (in thousands):

	Years ended December 31,		
	2000	1999	1998
Property costs:			
Acquisition costs	$ 7,534	$25,274	$12,070
Development costs	68,982	30,777	23,866
Total costs incurred	$76,516	$56,051	$35,936

Natural Gas and Oil Reserves

Proved reserves are estimated quantities of natural gas and oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods.

Proved natural gas and oil reserve quantities at December 31, 2000, 1999, and 1998, and the related discounted future net cash flows before income taxes are based on estimates prepared by Ryder Scott Company, L.P. and Schlumberger Holditch-Reservoir Technologies Consulting Services, independent petroleum engineers. Such estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission.

ATP OIL & GAS CORPORATION

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES—(Continued)

(Unaudited)

The Company's net ownership in estimated quantities of proved natural gas and oil reserves and changes in net proved reserves, all of which are located in the U.S. waters of the Gulf of Mexico, are summarized below:

	Millions of cubic feet of natural gas at December 31,		
	2000	1999	1998
Proved developed and undeveloped reserves:			
Beginning of the year	93,997	46,424	40,526
Revisions of previous estimates	(19,423)	3,033	(8,411)
Extensions and discoveries	7,239	2,257	—
Purchase of properties	42,318	58,816	24,059
Disposition of properties	(151)	—	(724)
Production	(22,410)	(16,533)	(9,026)
Proved reserves at the end of the year	101,570	93,997	46,424
Proved developed reserves:			
Beginning of year	67,314	39,728	31,080
End of year	42,502	67,314	39,728

	Barrels of oil, condensate, and natural gas liquids at December 31,		
	2000	1999	1998
Proved developed and undeveloped reserves (in thousands):			
Beginning of the year	1,689	586	942
Revisions of previous estimates	(46)	(131)	29
Extensions and discoveries	77	—	—
Purchase of properties	2,602	1,362	9
Disposition of properties	—	—	(243)
Production	(345)	(128)	(151)
Proved reserves at the end of the year	3,977	1,689	586
Proved developed reserves:			
Beginning of year	710	579	678
End of year	851	710	579

ATP OIL & GAS CORPORATION

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES—(Continued)

(Unaudited)

Standardized Measure

The standardized measure of discounted future net cash flows relating to the Company's ownership interests in proved natural gas and oil reserves as of year-end is shown below (in thousands):

	Years ended December 31,		
	2000	1999	1998
Future cash inflows	$1,139,404	$272,047	$106,772
Future operating expenses	(70,719)	(40,794)	(18,730)
Future development costs	(137,453)	(48,204)	(18,432)
Future net cash flows	931,232	183,049[2]	69,610
Future income taxes	(285,587)	(27,611)	—
Future net cash flows after income taxes	645,645	155,438	69,610
10% annual discount per annum	(121,164)	(26,732)	(8,302)
Standardized measure of discounted future net cash flows	$ 524,481	$128,706	$ 61,308[1]

(1) Net operating loss carryforwards and basis in natural gas and oil properties have eliminated the requirement for future income taxes.

(2) At December 31, 1999, future net cash flows totaling $112.5 million from ten properties, are committed to repayment of the Company's non-recourse borrowings.

Future cash inflows are computed by applying year-end prices of oil and gas to the year-end estimated future production of proved oil and gas reserves. The base prices used for the Pretax PV-10 calculation were public market prices on December 31 adjusted by differentials to those market prices. These price adjustment were done on a property-by-property basis for the quality of the oil and natural gas and for transportation to the appropriate location. The Henry Hub and Koch West Texas New Mexico Intermediate prices, before adjustment for quality and transportation, utilized in the Pretax PV-10 value at December 31, 2000 were $9.52 per mmbtu of natural gas and $23.75 per barrel of oil. At February 28, 2001, the Henry Hub and Koch West Texas New Mexico Intermediate prices were $5.10 per mmbtu of natural gas and $24.25 per barrel of oil. Estimates of future development and production costs are based on year-end costs and assume continuation of existing economic conditions and year-end prices. The estimated future net cash flows are then discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. The standardized measure of discounted cash flows is the future net cash flows less the computed discount.

ATP OIL & GAS CORPORATION

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES—(Continued)

(Unaudited)

Changes in Standardized Measure

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

	Years ended December 31,		
	2000	1999	1998
Beginning of year	$128,706	$61,308	$ 64,698
Sales of oil and gas, net of production costs	(64,381)	(29,394)	(17,217)
Net changes in income taxes	(193,613)	(27,611)	13,708
Net changes in price and production costs	416,738	9,931	(20,272)
Revisions of quantity estimates	(147,777)	4,176	(12,318)
Accretion of discount	15,632	6,131	7,841
Development costs incurred	18,134	15,550	19,780
Changes in estimated future development	(14,709)	(15,664)	(13,129)
Purchases of minerals-in-place	300,706	105,514	25,136
Sales of minerals-in-place	(525)	—	(4,886)
Extensions and discoveries	51,795	218	—
Changes in production rates, timing and other	13,775	(1,453)	(2,033)
Total changes in standardized increases	395,775	67,398	(3,390)
End of year	$ 524,481	$128,706	$ 61,308

Sales of natural gas and oil, net of natural gas and oil operating expenses, are based on historical pre-tax results. Sales of natural gas and oil properties, 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.

ATP OIL & GAS CORPORATION

SUPPLEMENTARY QUARTERLY INFORMATION
(unaudited)

	First Quarter	Second Quarter(5)	Third Quarter(5)	Fourth Quarter
2000				
Revenues	$15,127	$24,558	$20,462	$ 23,841
Costs and operating expenses	11,682	25,743 (1)(2)	23,778 (1)(2)	27,321 (1)(2)
Net income (loss) from operations	3,445	(1,185)	(3,316)	(3,480)
Net income (loss)	1,029	(2,742)	(4,251)	(4,434)
Income (loss) per common share:				
Basic and diluted	$ 0.07	$ (0.19)	$ (0.30)	$ (0.31)
1999				
Revenues	$10,498	$11,248	$11,325	$ 9,900
Costs and operating expenses	10,649	11,855 (3)	13,984 (3)	10,072 (3)
Net income (loss) from operations	(151)	(607)	(2,659)	(172)
Income (loss) before extraordinary item	(2,050)	(5,019)	(2,586)	(1,302)
Net income (loss)	(2,050)	24,166 (4)	(2,586)	(1,302)
Income (loss) per common share before extraordinary item:				
Basic and diluted	$ (0.14)	$ (0.35)	$ (0.18)	$ (0.09)
Income (loss) per common share:				
Basic and diluted	$ (0.14)	$ 1.69	$ (0.18)	$ (0.09)

(1) Includes impairment charges of $6.2 million, $0.8 million and $3.8 million during the second, third and fourth quarters respectively for three properties.

(2) Includes loss on speculative derivative position of $2.5 million, $3.7 million and $5.7 million during the second, third and fourth quarters respectively.

(3) Includes impairment charges of $2.5 million, $3.9 million and $1.1 million during the second, third and fourth quarters respectively for four properties.

(4) Includes extraordinary gain in the amount of $29.2 million recognized as a result of the discounted extinguishment of debt under our development program credit agreement.

(5) Results for the second and third quarters of 2000 have been revised to reflect the Company's written call option contracts on a mark-to-market basis. The Company recently determined that such contracts do not qualify for hedge accounting. The impact of the revision increased the previously reported amounts as follows:

	Second Quarter	Third Quarter
Revenues	$ 481	$ 319
Cost and operating expenses	1,764	1,531
Net loss from operations	1,283	1,212
Net loss	839	780
Basic and diluted loss per share	0.06	0.05

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 CO.

By: /s/ ALBERT L. REESE, JR.

Albert L. Reese, Jr.
Senior Vice President and Chief Financial Officer

POWER OF ATTORNEY

KNOWN ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints T. Paul Bulmahn and Albert L. Reese, Jr., and each of them, his or her true and lawful attorneys-in-fact and agents with full power of substitution and resubstitution for him or her and in his or her name, place and stead, in any and all capacities, to sign any or all amendments to this Form 10-K and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission granting unto said attorneys-in-fact and agents and each of them full power and authority to do and perform each and every act and thing requisite or necessary to be done in and about the premises, to all intents and purposes and as fully as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or their substitutes may lawfully do or cause to be done by virtue thereof.

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 30, 2001.

Signature	Title
/s/ T. PAUL BULMAHN **T. Paul Bulmahn**	Chairman, President and Director (Principal Executive Officer)
/s/ ALBERT L. REESE, JR. **Albert L. Reese, Jr.**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ KEITH R. GODWIN **Keith R. Godwin**	Vice President and Controller (Principal Accounting Officer)
/s/ Carol E. Overbey **Carol E. Overbey**	Director
/s/ GERARD SWONKE **Gerard Swonke**	Director
/s/ ARTHUR H. DILLY **Arthur H. Dilly**	Director
/s/ ROBERT C. THOMAS **Robert C. Thomas**	Director
/s/ WALTER WENDLANDT **Walter Wendlandt**	Director

INDEX OF EXHIBITS

Exhibit No.	Description
3.1	Amended and Restated Articles of Incorporation (incorporated by reference to Exhibit 3.1 of ATP's registration statement No. 333-46034 on Form S-1)
3.2	Restated Bylaws (incorporated by reference to Exhibit 3.2 of ATP's registration statement No. 333-46034 on Form S-1)
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 4.1 of ATP's registration statement No. 333-46034 on Form S-1)
10.1	Amended and Restated Credit Agreement, dated as of September 21, 1999, among ATP Oil & Gas Corporation, Chase Bank of Texas, National Association as Agent, and the Lenders Signatory thereto (incorporated by reference to Exhibit 10.1 of ATP's registration statement No. 333-46034 on Form S-1)
10.2	First Amendment to Amended and Restated Credit Agreement, dated as of September 21, 1999, among ATP Oil & Gas Corporation, Chase Bank of Texas, National Association, as Agent, and the Lenders Signatory thereto, effective as of June 30, 2000 (incorporated by reference to Exhibit 10.2 of ATP's registration statement No. 333-46034 on Form S-1)
10.3	Credit Agreement between ATP Oil & Gas Corporation and Aquila Energy Capital Corporation, dated April 9, 1999, effective as of March 31, 1999 (incorporated by reference to Exhibit 10.3 of ATP's registration statement No. 333-46034 on Form S-1)
10.4	First Amendment to Credit Agreement, dated April 9, 1999, by and between ATP Oil & Gas Corporation and Aquila Energy Capital Corporation (incorporated by reference to Exhibit 10.4 of ATP's registration statement No. 333-46034 on Form S-1)
10.5	Second Amendment to Credit Agreement, dated April 9, 1999, by and between ATP Oil & Gas Corporation and Aquila Energy Capital Corporation (incorporated by reference to Exhibit 10.5 of ATP's registration statement No. 333-46034 on Form S-1)
10.6	Gas Service Agreement, dated December 31, 1998, between American Citigas Company and ATP Energy, Inc. (incorporated by reference to Exhibit 10.6 of ATP's registration statement No. 333-46034 on Form S-1)
10.7	Marketing & Natural Gas Purchase Agreement, dated December 1, 1998, between ATP Energy, Inc. and El Paso Energy Marketing Company (incorporated by reference to Exhibit 10.7 of ATP's registration statement No. 333-46034 on Form S-1)
10.8	Purchase and Sale Agreement, effective as of May 1, 1999, between Eugene Offshore Holdings, LLC and ATP Oil & Gas Corporation (incorporated by reference to Exhibit 10.8 of ATP's registration statement No. 333-46034 on Form S-1)
10.9	ATP Oil & Gas Corporation 1998 Stock Option Plan (incorporated by reference to Exhibit 10.9 of ATP's registration statement No. 333-46034 on Form S-1)
10.10	First Amendment to the ATP Oil & Gas Corporation 1998 Stock Option Plan (incorporated by reference to Exhibit 10.10 of ATP's registration statement No. 333-46034 on Form S-1)
10.11	ATP Oil & Gas Corporation 2000 Stock Plan
21.1	Subsidiaries of ATP Oil & Gas Corporation (incorporated by reference to Exhibit 21.1 of ATP's registration statement No. 333-46034 on Form S-1)
24.1	Power of Attorney (included on the signature page to this Registration Statement)