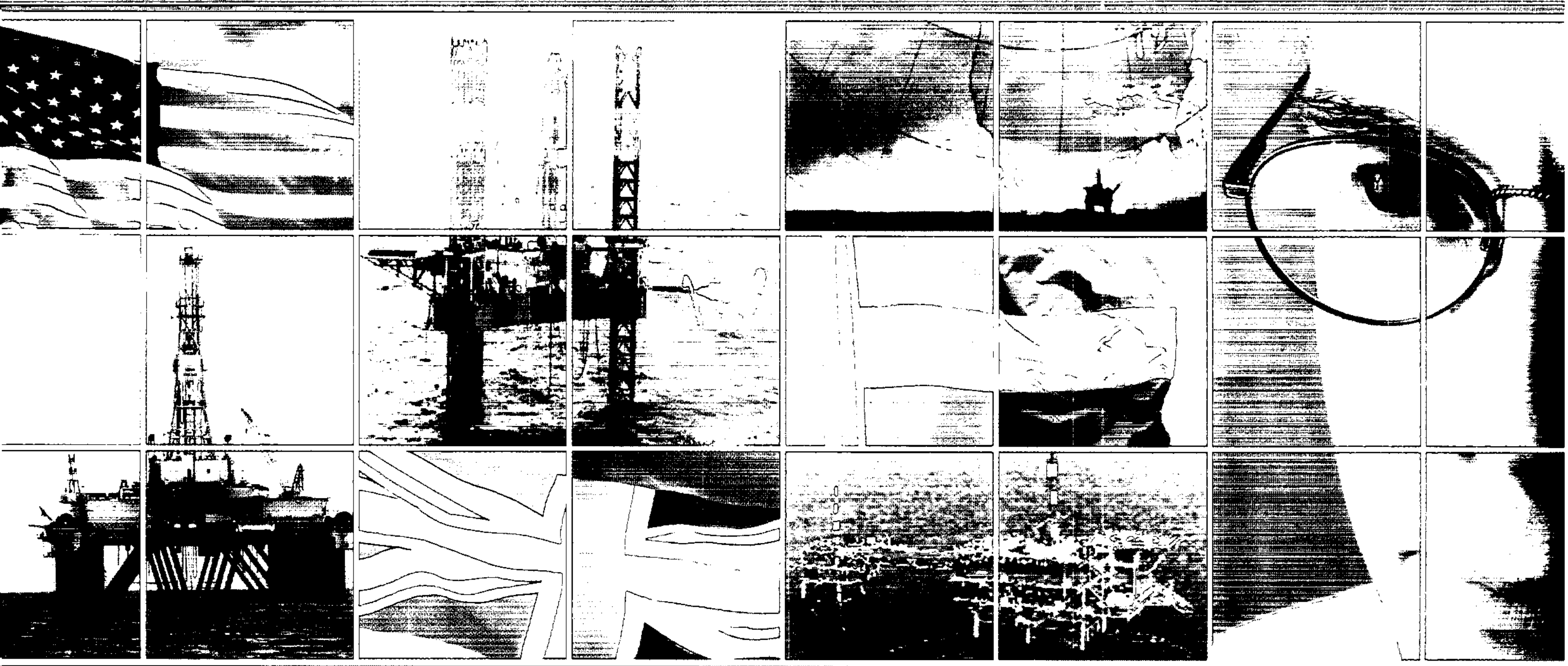
ATP
Oil & Gas Corporation



A LOGICAL PROGRESSION >>

Corporate Profile

ATP Oil & Gas Corporation ("ATP") is a focused development and production company operating in the Gulf of Mexico and the North Sea. The Company's strategy is to provide a high rate of return for investors by

- Acquiring lower-risk proven reserves
- Aggressively applying development and production technology to reduce project costs
- Operating development projects to ensure greater control of timing and costs
- Maximizing return on capital by moving quickly to property development, reducing time to first production

ATP Oil & Gas Corporation was established in 1991, and became a public company in February, 2001. The Company's common stock is traded on the NASDAQ under the symbol "ATPG."

Financial and Operating Highlights

Years ended December 31,	2002	2001	2000
($ in thousands, except per share amounts)			
Financial			
Revenues	$ 94,423	$113,174	$ 83,988
Net income (loss)	(4,700)	(21,383)	(10,398)
Basic & dilutive earnings (loss) per common share	(0.23)	(1.09)	(0.73)
Cash & cash equivalents	6,944	5,294	18,136
Net oil & gas properties	119,036	133,033	98,725
Total assets	182,055	177,564	161,993
Total debt	86,387	100,111	116,529
Stockholders' equity (deficit)	38,547	44,992	(13,179)
Operating:			
Capital expenditures	$ 34,873	$110,264	$ 76,474
Proved reserves			
Gas (MMcf)	195,538	194,509	101,570
Oil & condensate (MBbls)	5,740	6,753	3,977
Total (MMcfe)	229,979	235,027	125,433
Gulf of Mexico reserves	60%	66%	100%
North Sea reserves	40%	34%	–
Annual Production			
Gas (MMcf)	17,732	20,957	22,410
Oil & condensate (MBbls)	1,454	790	345
Total (MMcfe)	26,457	25,696	24,477

On the cover

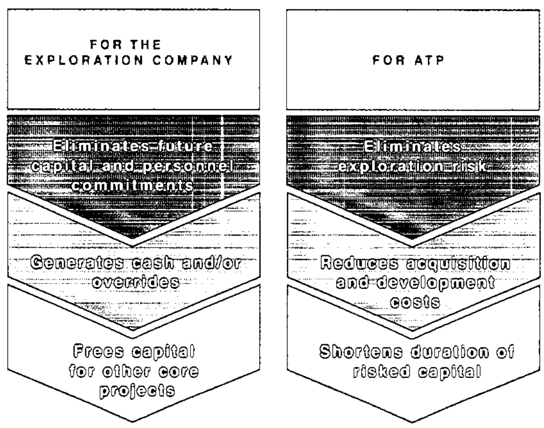
Leveraging our experience in the Gulf of Mexico, ATP has begun acquisition and development of gas properties in the UK and Dutch sectors of the North Sea. These relatively low risk basins are a logical next step for the Company, enabling us to maintain our rate-of-return focus while we diversify production. From left: South Marsh Island 190 in the Gulf of Mexico; Helvellyn Block 47/10 in the UK North Sea; infrastructure in the Dutch North Sea.

A LOGICAL PROGRESSION

ATP Oil & Gas Corporation is a proven provider of offshore oil and gas development solutions, dominating the niche we pioneered more than a decade ago. Our talented staff, strong technical capabilities and record of stable growth in the Gulf of Mexico are enabling us to successfully export our strategy to the UK and Dutch sectors of the North Sea – low risk basins with vast potential for increasing reserves and revenue.

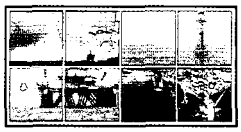
FOR YEARS, IT WAS THE SAME STORY: Exploration-oriented oil and gas companies would successfully discover hydrocarbons offshore they could not immediately develop.

That would leave two options. Temporarily suspend the well until the project could be budgeted and, thus, flirt with potential loss of lease issues. Or, the company could plug and abandon the property, incurring the attendant costs without ever capturing an ounce of revenue. Clearly, neither choice made good economic sense.



That scenario changed dramatically in 1991, when ATP Oil & Gas Corporation began to acquire and develop those non-strategic proved reserves. Our unique solution relieves the exploration company of capital, carrying costs, personnel and abandonment commitments while allowing them to "keep the dot on the map." More importantly, it provides assets for ATP to develop and produce without the time, cost or risk of exploration.

As operator of these properties, ATP controls the timing of development and the nature of expenditures. By applying innovative development technologies, we can bring these projects to production fairly quickly, which maximizes rate of return.



A BUSINESS MODEL WITH UNIVERSAL APPEAL

Our business model of offshore development solutions is unique, effective, repeatable and exportable. It allows us to operate effectively where there are

» A number of properties that exploration companies consider to be non-strategic

» Existing infrastructure and geographic proximity to markets and

» A consistently applied governmental regulatory framework for offshore development and production.

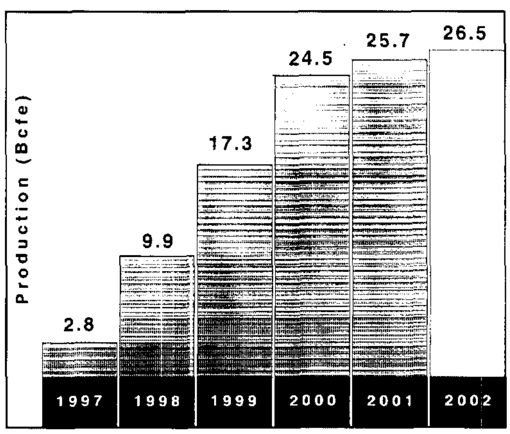
We are effectively positioned in the Gulf of Mexico, our initial area of operation, with substantial holdings in both shallow and deep water depths ranging from 12' to 1360'. **Over the last four years, ATP's reserve growth has averaged 292% per year, and in 2002 ATP recorded its seventh consecutive year in which the company increased production.**

The Gulf is also where we literally stretched our technical capabilities, setting the record for the longest subsea oil tieback (more than 17 miles of pipeline and umbilical in 1360 feet of water at Ladybug well No.1 in Garden Banks Block 409). We focus on utilizing cost-efficient development techniques and methods. Our ability to adapt current technology to new situations opens opportunities for us. ATP also set the record for the longest direct hydraulic umbilical (11.7 miles).

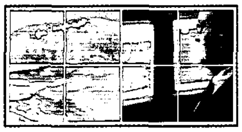
Prospects in the Gulf of Mexico remain healthy – we're evaluating more properties there than ever before – however, ATP has now established a presence in the UK and Dutch sectors of the North Sea. Activities in those areas are additive to what ATP is doing in the Gulf.

Production

(1997 - 2002)



5-Year Compounded Annual Growth Rate: ATP = 57%

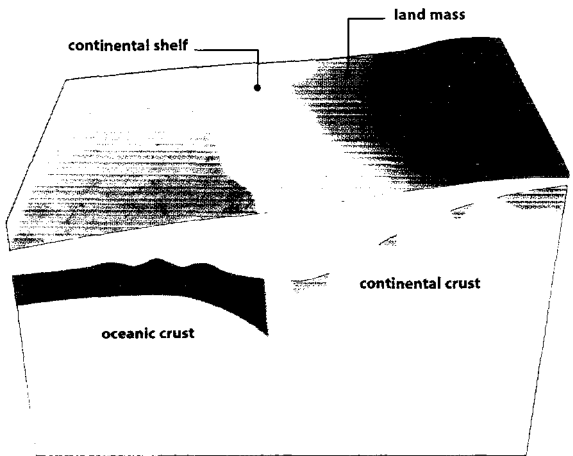


AN EASY TRANSITION TO THE NORTH SEA

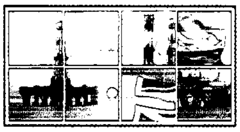
The image of the North Sea is one of rugged waters whipped furiously by treacherous winds. In the Northern North Sea off Norway, for example, that depiction is on point. But in the Southern Gas Basin, where ATP inaugurated in 2000 its international expansion, the conditions are actually quite similar to what we know in the Gulf. We understand the geologic and climatic variables; the area's water depths of 50 to 200 feet are well within our expertise.

UK SECTOR. An invitation from Britain's Department of Trade and Industry (DTI) accelerated our move into the UK North Sea. The DTI had been wrestling with what to do with its "fallow field list" – natural gas reservoirs with proved reserves that had not been developed within a six-year time frame. Large exploration companies considered these fields non-strategic or marginal and there was no one with an offshore developmental strategy like ours.

Cognizant of our accomplishments in the Gulf, the DTI determined that our approach would fit the government's model for producing developments. We established a local office with technically proficient UK nationals and the DTI acted to approve ATP Oil & Gas (UK) Limited as an operator. It was unusual for the DTI to grant operator status to a company that had not first served as the non-operating partner of a major exploration company in the North Sea. That is a testimonial to the operating prowess of ATP in the Gulf of Mexico and to the high caliber personnel of the company in the Gulf and North Sea.



There are a number of similarities between the Southern Gas Basin of the North Sea and the Gulf of Mexico, including a continental shelf.



We pride ourselves in finding and selecting top-flight individuals with practical experience who can use available technology to solve problems.

DUTCH SECTOR. Our steady progress in the UK provided the practical foundation for our entry into the North Sea Dutch sector.

For nearly 40 years, the giant Groningen field has been the source of most natural gas production in the Netherlands. However, in order to keep from depleting Groningen, the country of the Netherlands has encouraged development of other resources. ATP believes its expertise as an offshore operator of oil and gas developments is appropriate for the continuing production of Dutch offshore reserves.

ATP Oil & Gas (Netherlands) B.V. has been approved as an operator in the Dutch sector and development of ATP's initial project is already underway.

Though ATP is relatively young in the North Sea, we bring established talent and techniques with us. We are experienced at controlling expenses and are able to transfer to the North Sea the cost-effective and fit-for-purpose techniques we perfected in the Gulf.

DEAR FELLOW SHAREHOLDER:

The year 2002 will be remembered for the ATP expansion in the North Sea into the Dutch sector, for a continuation of seven (7) consecutive years of production increases, and for financially strengthening the company's balance sheet.

As I sat down to write this letter to you, my in-box contained an industry press release. The headline announced a proposed natural gas pipeline to be constructed by the Netherlands' gas transmission operator, Gastransport, from the Netherlands to Bacton, England. One sentence was particularly significant: "Gastransport's pipeline proposal underscores the growing importance of the UK gas market to European companies **as the UK's locally-derived supplies of gas dwindle.**"

To positively address gas supply is the reason ATP is an offshore development operator in the Southern Gas Basin of the North Sea. As a logical progression from our Gulf of Mexico activities, we are focusing on acquisition and development in an area with significant undeveloped gas discoveries near England and the Netherlands. The strategy ATP perfected in the Gulf of Mexico, to develop proved reserves non-strategic to the exploration companies which discovered them, is particularly effective in a mature area with pipeline infrastructure, growing demand and decreasing natural gas supplies. An experienced development operator, like ATP, able to bring its repeatable strategy from the Gulf to the UK and the Netherlands can deliver a necessary ingredient to bolster the dwindling gas supplies.

Foremost among our UK sector North Sea activities in 2002 was the development of a subsea well in Helvellyn Field which flow-tested at 60 MMcfe per day. This figure is highly significant in that our share will materially increase ATP's company-wide production. We expect production at Helvellyn to commence in the second quarter of 2003, a scant 10 months after government approval of ATP's development plan. Development activities have also already begun at the UK Venture reservoir and, in 2002 ATP was awarded two additional blocks near the UK Tors reservoirs which serve to enhance a "hub" development concept for the offshore blocks already acquired by the company.

At year-end 2002, our stock was ranked the industry's third-best performer by one of the nation's leading full-service retail brokerages.

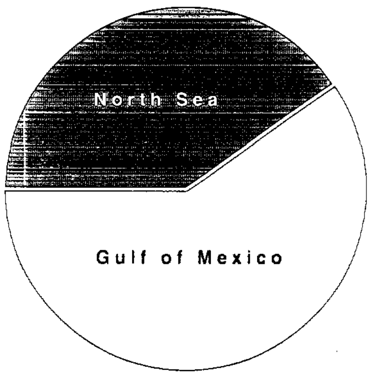
In the Dutch sector of the North Sea ATP has already acquired one block on which the company immediately began development activities. ATP anticipates first production from that Netherlands project in 2004. Its growing experience in the region enables ATP to optimize development strategies.

Even with our expanding emphasis in the North Sea, the Gulf of Mexico remains at the core of the company and our domestic operations continue to perform reliably and dependably. Because of that consistency ATP, for the seventh consecutive year, increased its annual production. Production was 26.5 Bcfe resulting in a five-year compounded annual growth rate of 57%. That ATP also met its production guidance on a modest capital budget attests to our operating efficiency. Further, ATP commenced to develop West Cameron 101, recompleted High Island A354, began initial production at Eugene Island 71 and South Marsh Island 189/190, acquired West Cameron 284 and became the successful high bidder on South Padre Island 1151 in the Western Gulf of Mexico. For 2003 ATP expects to approximately double its capital expenditures in the Gulf.

ATP also continues to perform consistently in other material ways. Our cash flow increase to $51 million was sufficient to fully fund all 2002 capital commitments. The company strengthened its balance sheet in 2002 by reducing long-term bank debt $14 million and improving its working capital by over $15 million. ATP's greater financial flexibility should allow it to take advantage of future opportunities at attractive terms.

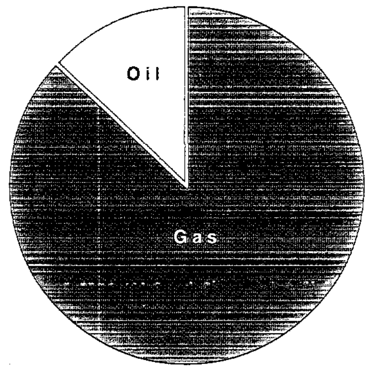
PROVED RESERVES

40% North Sea



PROVED RESERVES

85% Gas



Other highlights of the year:

- ATP's average growth each year of Reserve Replacement over the last four years was 292%.
- ATP, for conducting its offshore operations in a safe and environmentally responsible manner, was nominated for the **National Safety Award of Excellence (SAFE)** by the Minerals Management Service (MMS) of the U.S. Department of the Interior for a second consecutive year.
- ATP recorded a 3-year Finding and Development (F&D) cost of $1.09/Mcfe, better than most peer and median comparisons.

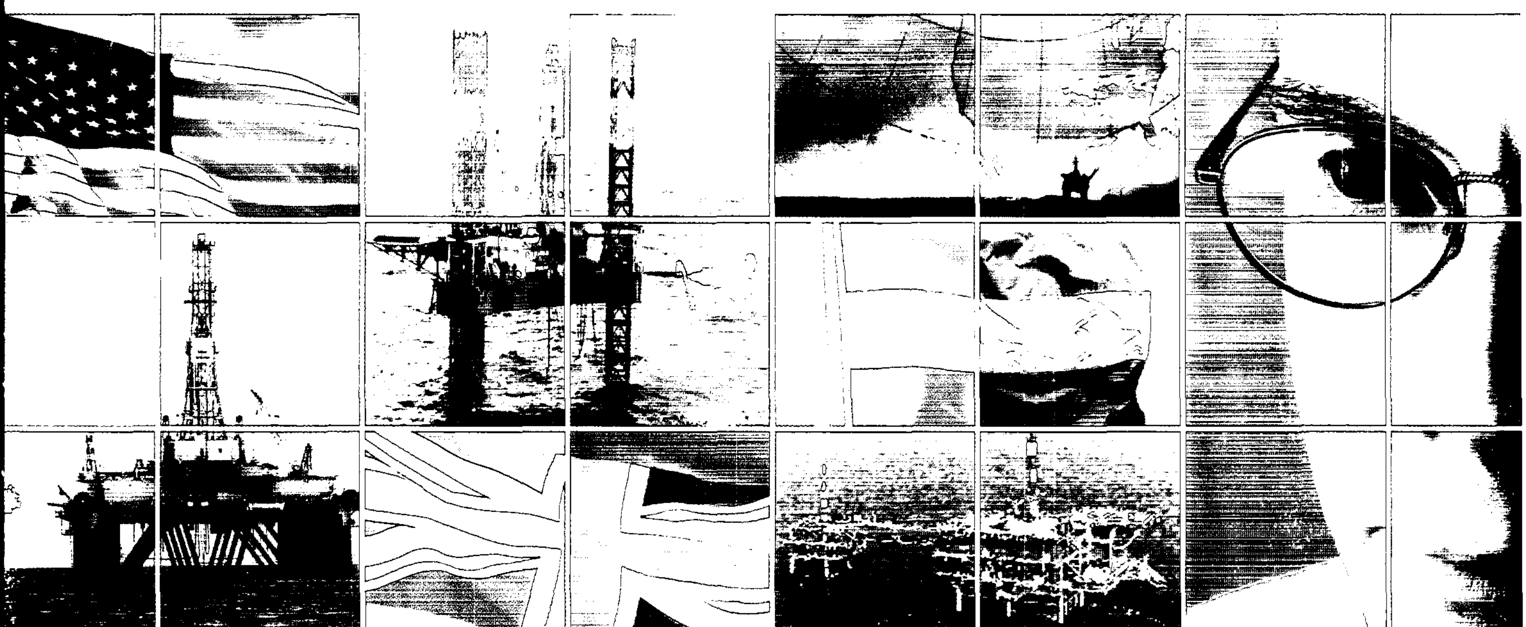
Our business plan has been validated on an international level as we have gained momentum in our North Sea expansion. As we move forward with both domestic and international programs, we believe ATP will continue to be acknowledged as innovative leaders and problem solvers. Our level of technical expertise is especially well regarded in the industry – not only for using new technologies but also for utilizing existing technologies to obtain greater effectiveness and productivity. It is not unusual for ATP to operate and own 100% of its projects. As ATP has moved to deeper water and the international arena, ATP has joined with major industry players, for example, Royal Dutch/Shell, ConocoPhillips, Unocal, Gaz de France, to develop these new horizons. That ATP is the operator of each of the various projects, with these major industry co-owners, is recognition of ATP's talent on a very high plane.

As always, I'd like to thank our shareholders for their continuing confidence. I wish also to express my appreciation to the ATP staff around the world for their tremendous efforts. We look forward to continuing to enhance equity value in 2003.

Sincerely,

T. Paul Bulmahn
Chairman & President

ATP
OIL & GAS
CORPORATION



2002 ANNUAL REPORT >>

2002 FINANCIAL REVIEW

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SELECTED FINANCIAL DATA

The selected historical financial information was derived from, and is qualified by reference to our consolidated financial statements, including the notes thereto, appearing elsewhere in this report. The following data should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations".

	Years Ended December 31,				
	2002	2001	2000	1999	1998
(In thousands, except per share data)					
Statement of Operations Data:					
Revenues:					
Oil and gas production	$ 88,151	$105,757	$ 75,940	$ 34,981	$ 20,410
Gas sold – marketing	6,272	7,417	8,015	7,703	–
Gain on sale of oil and gas properties	–	–	33	287	–
Total revenues	94,423	113,174	83,988	42,971	20,410
Cost and operating expenses:					
Lease operating	16,764	14,806	11,559	5,587	3,193
Gas purchased – marketing	6,087	7,218	7,788	7,402	–
Geological and geophysical expenses	154	1,068	–	–	–
General and administrative	10,287	9,981	5,409	3,541	2,591
Non-cash compensation expense (general and administrative)	595	3,364	–	–	–
Depreciation, depletion and amortization	43,390	53,428	40,569	22,521	17,442
Impairment of oil and gas properties	6,844	24,891	10,838	7,509	5,072
Loss on unsuccessful property acquisition	–	3,147	–	–	–
Other expense	–	–	450	–	–
Total operating expenses	84,121	117,903	76,613	46,560	28,298
Income (loss) from operations	10,302	(4,729)	7,375	(3,589)	(7,888)
Other income (expense):					
Interest income	73	884	451	202	141
Interest expense	(10,418)	(10,039)	(11,907)	(9,399)	(7,963)
Other income	1,081	–	–	–	–
Realized loss on derivative instruments	(153)	(19,348)	(4,662)	–	–
Unrealized gain (loss) on derivative instruments	(8,166)	1,265	(7,249)	–	–
Loss before income taxes and extraordinary item	(7,281)	(31,967)	(15,992)	(12,786)	(15,710)
Income tax benefit – deferred	2,581	11,186	5,594	1,829	–
Loss before extraordinary item	(4,700)	(20,781)	(10,398)	(10,957)	(15,710)
Extraordinary item, net of tax	–	(602)	–	29,185	–
Net income (loss)	$ (4,700)	$ (21,383)	$ (10,398)	$ 18,228	$(15,710)
Weighted average number of common shares outstanding – basic and diluted	20,315	19,704	14,286	14,286	11,926
Loss per common share before extraordinary item – basic and diluted	$ (0.23)	$ (1.06)	$ (0.73)	$ (0.77)	$ (1.32)
Net income (loss) per common share:					
Basic and diluted	$ (0.23)	$ (1.09)	$ (0.73)	$ 1.28	$ (1.32)
Balance Sheet Data:					
Cash and cash equivalents	$ 6,944	$ 5,294	$ 18,136	$ 17,779	$ 3,411
Working capital	(13,699)	(29,071)	(3,835)	14,115	(5,106)
Net oil and gas properties	119,036	133,033	98,725	72,278	47,612
Total assets	182,055	177,564	161,993	107,054	61,354
Total debt	86,387	100,111	116,529	91,723	62,690
Total liabilities	143,508	132,572	175,172	109,835	82,363
Shareholders' equity (deficit)	38,547	44,992	(13,179)	(2,781)	(21,009)

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

We are engaged in the acquisition, development and production of natural gas and oil properties in the Gulf of Mexico and in the 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.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our consolidated financial statements are prepared in conformity with accounting principles generally accepted in the U.S., which require management to make estimates and assumptions that affect the reported amounts of the assets and liabilities and disclosures of contingent assets and liabilities as of the date of the balance sheet as well as the reported amounts of revenues and expenses during the reporting period. We routinely make estimates and judgments about the carrying value of our assets and liabilities that are not readily apparent from other sources. Such estimates and judgments are evaluated and modified as necessary on an ongoing basis. We believe that of our significant accounting policies (see Note 2, Summary of Significant Accounting Policies and Estimates, to our Consolidated Financial Statements), the following may involve a higher degree of judgment and complexity.

OIL AND GAS RESERVES

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

OIL AND GAS PRODUCING ACTIVITIES

We follow 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 units-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 geological and geophysical testing costs are generally charged to expense unless the costs can be specifically attributed to determining the placement for a future developmental well location.

Expenditures for repairs and maintenance are charged to expense as incurred; renewals and betterments are capitalized. The costs and related accumulated depreciation, depletion, and amortization of properties sold or otherwise retired are eliminated from the accounts, and gains or losses on disposition are reflected in the statements of operations.

We perform an impairment analysis whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. An impairment allowance is provided on an unproved property when we determine that the property will not be developed. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management's estimates of future oil and gas prices to the estimated future production of oil and gas reserves over the economic life of the property. Future net cash flows are based upon our independent reservoir 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 or other development activities. For a property determined to be impaired, an impairment loss equal to the difference between the carrying value and the estimated fair value of the impaired property will be recognized. Fair value, on a depletable unit basis, is estimated to be the present value of the aforementioned expected future net cash flows. Any impairment charge incurred is recorded in accumulated depreciation, depletion, impairment and amortization to reduce our recorded basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units' estimated reserves, future cash flows and fair value.

CONTINGENT LIABILITIES

In preparing financial statements at any point in time, management is periodically faced with uncertainties, the outcomes of which are not within its control and will not be known for prolonged periods of time. As discussed in the Notes to Consolidated Financial Statements, we are involved in actions, which if determined adversely, could have a material negative impact on our financial position, results of operations and cash flows. Management, with the assistance of counsel makes estimates, if determinable, of ATP's probable liabilities and records such amounts in the consolidated financial statements. Such estimates may be the minimum amount of a range of probable loss when no single best estimate is determinable. Disclosure is made, when determinable, of any additional possible amount of loss on these claims, or if such estimate cannot be made, that fact is disclosed. Along with our counsel, we monitor developments related to these legal matters and, when appropriate, we make adjustments to recorded liabilities to reflect current facts and circumstances. Although it is difficult to predict the ultimate outcome of these matters, management believes that the recorded amounts, if any, are reasonable.

PRICE RISK MANAGEMENT ACTIVITIES

As of July 1, 2002, we performed the requisite steps to qualify our derivative instruments for hedge accounting treatment under the provisions of Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standard ("SFAS") No. 133, *"Accounting for Derivative Instruments and Hedging Activities"* ("SFAS 133"), as amended. Under SFAS 133 all derivative instruments are recorded on the balance sheet at fair value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective. For qualifying fair value hedges, the gain or loss on the derivative is offset by related results of the hedged item in the statement of operations. Gains and losses on hedging instruments included in accumulated other comprehensive income (loss) are reclassified to oil and gas revenues in the period that the related production is delivered. Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at market value in the consolidated balance sheet, and the associated unrealized gains and losses are recorded as current expense or income in the consolidated statement of operations. Prior to July 1, 2002, gains or losses from our derivative instruments were included in other income (expense).

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

RESULTS OF OPERATIONS

The following table sets forth selected financial and operating information for our natural gas and oil operations inclusive of the effects of price risk management activities:

	Years Ended December 31,		
	2002	2001	2000
Production:			
Natural gas (MMcf)	17,732	20,957	22,410
Oil and condensate (MBbls)	1,454	790	345
Total (MMcfe)	26,457	25,696	24,477
Revenues (in thousands):			
Natural gas	$56,659	$ 88,908	$ 94,051
Effects of risk management activities (1)	(2,764)	(19,751)	(26,729)
Total	$53,895	$ 69,157	$ 67,322
Oil and condensate	$32,756	$ 16,849	$ 10,112
Effects of risk management activities (1)	(615)	–	(1,494)
Total	$32,141	$ 16,849	$ 8,618
Natural gas, oil and condensate	$89,415	$105,757	$104,163
Effects of risk management activities (1)	(3,379)	(19,751)	(28,223)
Total	$86,036	$ 86,006	$ 75,940
Average sales price per unit:			
Natural gas (per Mcf)	$ 3.20	$ 4.24	$ 4.20
Effects of risk management activities (per Mcf)	(0.16)	(0.94)	(1.19)
Total (per Mcf)	$ 3.04	$ 3.30	$ 3.01
Oil and condensate (per Bbl)	$ 22.53	$ 21.33	$ 29.35
Effects of risk management activities (per Mcf)	(0.42)	–	(4.34)
Total (per Bbl)	$ 22.11	$ 21.33	$ 25.01
Natural gas, oil and condensate (per Mcfe)	$ 3.38	$ 4.12	$ 4.26
Effects of risk management activities (per Mcfe)	(0.13)	(0.77)	(1.16)
Total (per Mcfe)	$ 3.25	$ 3.35	$ 3.10
Expenses (per Mcfe):			
Lease operating	$ 0.63	$ 0.58	$ 0.47
General and administrative	0.39	0.39	0.22
Depreciation, depletion and amortization	1.64	2.08	1.66

(1) *Represents the net loss on the settlement of derivatives attributable to actual production.*

YEAR ENDED DECEMBER 31, 2002 COMPARED TO YEAR ENDED DECEMBER 31, 2001

For the year ended December 31, 2002, we reported a net loss of $4.7 million, or $0.23 per share as compared to a net loss of $21.4 million, or $1.09 per share in 2001.

Oil and Gas Revenue / Excluding the effects of settled derivatives, our revenue from natural gas and oil production for 2002 decreased 16% compared to 2001, from $105.8 million to $89.4 million. This decrease was primarily due to an approximate 18% decrease in our average sales price per Mcfe from $4.12 per Mcfe in 2001 to $3.38 in 2002. This decrease was partially offset by a 3% increase in production volumes from 25.7 Bcfe to 26.5 Bcfe due primarily to two properties that were completed and began production in 2002. Additionally, one property was completed in September 2001 but did not contribute a full year of production until 2002.

Early in the fourth quarter, we were forced to shut-in a majority of our Gulf of Mexico production when Hurricane Lili, a Category 4 storm, blew through the central Gulf. Our current production continues to be hampered by the damage wrought by Hurricane Lili and we estimated a fourth-quarter impact of approximately 1.0 Bcfe. We carry insurance, subject to normal deductibles, that covers both the physical damage and loss of production income, which will partially mitigate the financial impact of this hurricane.

Marketing Revenue / Revenues from natural gas marketing activities decreased to $6.3 million in 2002 as compared to $7.4 million in 2001. This decrease was due to a decrease in the sales price per MMBtu. The average sales price per MMBtu decreased from $4.06 in 2001 to $3.44 in 2002. For more information regarding this marketing activity, see Note 13 to the Consolidated Financial Statements.

Lease Operating Expense / Our lease operating expense for 2002 increased 13% from $14.8 million ($0.58 per Mcfe) to $16.8 million ($0.63 per Mcfe). This increase was primarily the result of an increase in the number of producing wells we own and an increase in their total production volume. Lease operating expense per Mcfe increased due to higher than expected repairs and maintenance costs on our platforms and costs incurred related to the hurricane and tropical storm.

Gas Purchased-Marketing / Our cost of purchased gas was $6.1 million for 2002 compared to $7.2 million for 2001. The average gas cost decreased from $3.96 per MMBtu in 2001 to $3.34 per MMBtu in 2002. For more information regarding this marketing activity, see Note 13 to the Consolidated Financial Statements.

Geological and Geophysical / In 2002, we recorded approximately $0.2 million of costs related to the acquisition of 3-D seismic data purchased for certain properties in the U.K. Sector – North Sea. In 2001, we recorded $1.1 million of these same costs on properties in both the Gulf of Mexico and the U.K. Sector – North Sea.

General and Administrative Expense / General and administrative expense increased to $10.3 million for 2002 compared to $10.0 million for 2001. The primary reason for the increase was the result of higher compensation related costs in 2002 which was substantially offset by a bad debt allowance recorded in 2001.

Non-Cash Compensation Expense / In 2002, we recorded a non-cash charge to compensation expense of approximately $0.6 million for options granted since September 1999 through the date of our initial public offering ("IPO") on February 5, 2001 (the "measurement date"). The total expected expense as of the measurement date is recognized in the periods in which the option vests. Each option is divided into three equal portions corresponding to the three vesting dates (April 10, 2001, February 9, 2002, and February 9, 2003), with the related compensation cost for each portion amortized straight-line over the period to the vesting date. In 2001, we recorded a non-cash compensation expense of $2.9 million for the above options and an additional non-cash compensation expense of $0.5 million related to certain options granted prior to September 1999 and exercised during 2001. The additional expense was recorded as a result of the manner in which those shares were exercised.

Depreciation, Depletion and Amortization Expense / Depreciation, depletion and amortization expense ("DD&A") decreased 19% from $53.4 million in 2001 to $43.4 million in 2002. The average DD&A rate was $1.64 per Mcfe during 2002 compared to $2.08 per Mcfe during 2001. This decrease in the rate was attributable to (1) impairments taken in 2001, (2) higher than expected costs of an abandonment completed in 2001 and (3) a new property brought on line in 2002 with a lower average DD&A rate than those properties producing in 2001.

Impairment Expense / On two of our properties in 2002 and eight of our properties in 2001, the future undiscounted cash flows were less than their individual net book value. As a result, we recorded impairments of $6.8 million in 2002 and $24.9 million in 2001. The impairments in 2002 were primarily the result of reductions in recoverable reserves. The impairments in 2001 were primarily the result of drilling a non-commercial development well ($8.3 million), a decrease in expected future gas prices and reductions in recoverable reserves. The impairments were calculated as the difference between the carrying value and the estimated fair value of the impaired depletable unit.

Other Income (Expense) / Effective July 1, 2002, we qualified for hedge accounting treatment under the provisions of SFAS 133 and began recording any gains or losses on settled derivative instruments as a component of oil and gas revenue. The effective portion of any changes in the fair market value of open positions at the end of the period is recorded in other comprehensive income (loss). The loss on derivative instruments of $8.3 million in 2002 represents amounts recorded prior to July 1, 2002 and is comprised of a realized loss of $0.1 million for derivative contracts settled in the first half of 2002 and an unrealized loss of $8.2 million representing the change in fair market value of the open derivative positions at June 30, 2002. In 2001, we recorded a loss on derivative instruments of $18.1 million. The net loss in 2001 was comprised of a realized loss of $19.3 million for derivative contracts settled in the period and an unrealized gain of $1.2 million representing the change in fair market value of the open derivative positions at December 31, 2001.

Interest expense increased by $0.4 million over 2001 due to amounts owed on a long-term contract with a third party and we capitalized $0.3 million of interest for the year ended December 31, 2002 related to one property in the U.K. Sector – North Sea.

Other income includes $0.6 million of accrued insurance proceeds related to the loss of production from Hurricane Lili in October 2002 and the forgiveness of interest of $0.4 million related to amounts owed on a long-term contract with a third party. We filed an insurance claim during the fourth quarter of 2002 covering the estimated damages and lost production from the Gulf of Mexico region resulting from the effects of Hurricane Lili in October 2002. Our financial statements reflect probable amounts recoverable, net of deductibles, of approximately $1.5 million for damages to ten properties and lost production on four properties through December 31, 2002. The total claim will be determined when the final documentation is received and approved and any remaining payment related to 2003 will be recorded when we have a firm settlement commitment from the insurance company.

YEAR ENDED DECEMBER 31, 2001 COMPARED TO YEAR ENDED DECEMBER 31, 2000

For the year ended December 31, 2001, we reported a net loss of $21.4 million, or $1.09 per share as compared to a net loss of $10.4 million, or $0.73 per share in 2000.

Oil and Gas Revenue / Excluding the effects of settled derivatives, our revenue from natural gas and oil production for 2001 increased 2% over 2000, from $104.2 million to $105.8 million. This increase resulted from a slight increase in the price of natural gas and a 5% increase in production, partially offset by a 27% decrease in the price of oil. The increase in production volumes from 24.4 Bcfe to 25.7 Bcfe was attributable to 13 properties that were on production during 2001 that were not on production during 2000. This increase in production was offset by the natural decline in our existing offshore properties. Risk management activities, which were included in oil and gas revenues in 2000 would have decreased oil and natural gas revenues by $24.4 million, or $0.95 per Mcfe in 2001 and decreased $28.2 million, or $1.16 per Mcfe in 2000.

Marketing Revenue / Revenues from natural gas marketing activities decreased to $7.4 million in 2001 as compared to $8.0 million in 2000. This decrease was due to a decrease in the sales price per MMBtu. The average sales price per MMBtu decreased from $4.38 in 2000 to $4.06 in 2001. For more information regarding this marketing activity, see Note 13 to the Consolidated Financial Statements.

Lease Operating Expense / Our lease operating expense for 2001 increased 28% from $11.6 million to $14.8 million. This increase was primarily the result of an increase in the number of producing wells we own and an increase in their total production volume. Additionally, the lease operating expense per Mcfe on those properties acquired in 2001 was higher due to cost structures and contract obligations in place at the time of acquisition. Transportation related costs increased ($0.6 million) and workover spending decreased ($0.9 million) as compared to 2000.

Gas Purchased-Marketing / Our cost of purchased gas was $7.2 million for 2001 compared to $7.8 million for 2000. The average gas cost decreased from $4.26 per MMBtu in 2000 to $3.96 per MMBtu in 2001. For more information regarding this marketing activity, see Note 13 to the Consolidated Financial Statements.

Geological and Geophysical / In 2001, we recorded $1.1 million of costs related to the acquisition of 3-D seismic data purchased for certain properties in the Gulf of Mexico and the U.K. Sector – North Sea.

General and Administrative Expense / General and administrative expense increased to $10.0 million for 2001 compared to $5.4 million for 2000. The primary reason for the increase was the result of compensation and related expenses due to an increase in the number of employees in our Houston office from 28 at the end of 2000 to 39 at the end of 2001 ($0.9 million) and the opening of our U.K. office in the third quarter of 2000 ($1.7 million). As a result of becoming a public company in 2001, we incurred costs such as insurance, filing fees, professional fees, investor relations expenses and other expenses related to public company requirements ($1.3 million).

Non-Cash Compensation Expense / In 2001, we recorded a non-cash compensation expense of $3.4 million. A portion of the expense ($2.9 million) is related to options granted from September 1999 to the date of our IPO and is based on the difference between the exercise price for those options and the fair market value of our stock as determined by the IPO price of $14.00 per share. The expense is 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. The remaining expense ($0.5 million) was related to certain options granted prior to September 1999 and exercised in the current year. The expense was recorded on those exercises as the method in which those shares were exercised required us to account for the options under variable accounting.

Depreciation, Depletion and Amortization Expense / Depreciation, depletion and amortization expense increased 32% from $40.6 million in 2000 to $53.4 million in 2001. The average DD&A rate was $2.08 per Mcfe during 2001 compared to $1.66 per Mcfe during 2000.

Impairment Expense / As of December 31, 2001, the future undiscounted cash flows for our properties were $354.2 million and the net book value for the properties was $157.9 million before current year impairment expense. At 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. However, on eight of our properties in 2001 and three of our properties in 2000, the future undiscounted cash flows were less than their individual net book value. As a result, we recorded impairments of $24.9 million in 2001 and $10.8 million in 2000. The impairments in 2001 were primarily the result of drilling a non-commercial development well at our Main Pass 282 property ($8.3 million), a decrease in expected future gas prices and reductions in recoverable reserves. In 2000, the impairments were primarily the result of a reduction in recoverable reserves individually attributable to the particular properties.

Other Income (Expense) / In 2001, we recorded a loss on derivative instruments of $18.1 million comprised of a realized loss of $19.3 million and an unrealized gain of $1.2 million. The realized loss represents derivative contracts settled in 2001, while the offsetting gain represents the fair market value of the open derivative positions at December 31, 2001. Prior to the adoption of SFAS 133, realized gains or losses were recorded as a component of revenue. 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 addition, we recorded an expense of $7.6 million ($3.0 million realized and $4.6 million unrealized) related to losses associated with our written call option contracts. In both of these situations in 2000, we were required to account for the positions using the mark-to-market method.

Interest expense decreased from $11.9 million in 2000 to $10.0 million in 2001 primarily due to lower debt levels following the use of proceeds from our IPO and as a result of lower interest rates. We capitalized zero and $0.7 million of interest for the years ended December 31, 2001 and 2000, respectively.

LIQUIDITY AND CAPITAL RESOURCES

General / We have financed our acquisition and development activities through a combination of project-based development arrangements, bank borrowings and proceeds from our February 2001 IPO, as well as cash from operations and the sale on a promoted basis of interests in selected properties. We intend to finance our near-term development projects in the Gulf of Mexico and North Sea through available cash flows and the potential sell down of interests in the development projects. As operator of all of our projects in development, we have the ability to significantly control the timing of most of our capital expenditures. We believe the cash flows from operating activities combined with our ability to control the timing of substantially all of our future development and acquisition requirements will provide us with the flexibility and liquidity to meet our future planned capital requirements.

However, future cash flows are subject to a number of variables including changes in the borrowing base, the level of production from our properties, oil and natural gas prices and the impact, if any, of commitments and contingencies. Future borrowings under credit facilities are subject to variables including the lenders' practices and policies, changes in the prices of oil and natural gas and changes in our oil and gas reserves. A material reduction in the borrowing base or the institution of a monthly reduction amount by our lenders would have a material negative impact on our cash flows and our ability to fund future obligations. No assurance can be given that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of operations and capital expenditures. Historically, in periods of reduced availability of funds from either cash flows or credit sources we have delayed planned capital expenditures and will continue do to so when necessary. While the delay decreases the amount of capital expenditures in the current period, it could negatively impact our future revenues and cash flows.

Cash Flows

	Years Ended December 31,		
	2002	2001	2000
(in thousands)			
Cash provided by (used in):			
Operating activities	$ 51,298	$ 41,356	$ 57,157
Investing activities	(35,167)	(110,810)	(76,835)
Financing activities	(14,481)	56,612	20,035

Operating activities / Net cash provided by operating activities in 2002 was $51.3 million compared to $41.4 million in 2001. The change in accounts payable reflects the primary reason for this increase as we utilized a substantial portion of our operating cash flow in 2001 to reduce amounts owed to third parties. This increase was partially offset by an 18% decrease in our average sales price per Mcfe. Restricted cash of $0.4 million represents funds set aside to satisfy payment conditions in our drilling contract for development in the U.K.

Investing activities / Cash used in investing activities decreased in 2002 to $35.2 million of which $34.9 was for acquisition and development activities. We incurred no costs for two acquisitions made in 2002 and approximately $1.0 million for the acquisition of an undeveloped block in the Gulf of Mexico. Developmental capital expenditures in the Gulf of Mexico and the North Sea were approximately $17.5 million and $16.4 million, respectively. In 2001, capital expenditures for acquisition and development were $25.9 million and $78.8 million, respectively, and $5.6 million was used to purchase the overriding royalty interests associated with the repayment of our non-recourse debt.

Financing activities / Cash used in financing activities in 2002 represents net principal payments on our credit facility. Cash provided from financing activities in 2001 included the proceeds from our initial public offering in February 2001 of $78.3 million, repayment of prior credit facilities of $119.9 million and proceeds of $100.0 million from our credit facility and promissory note.

Amounts borrowed under our credit agreements were as follows for the dates indicated (in thousands):

	December 31,	
	2002	2001
Credit facility	*$56,000*	*$ 70,000*
Note payable, net of unamortized discount of $863 and $1,139	30,387	30,111
Total debt	$86,387	$100,111

Credit Facility / We have a $100.0 million senior-secured revolving credit facility which is secured by substantially all of our U.S. oil and gas properties, as well as by approximately two-thirds of the capital stock of our foreign subsidiaries and is guaranteed by our wholly owned subsidiary, ATP Energy, Inc. The amount available for borrowing under the credit facility is limited to the loan value, as determined by the bank, of oil and gas properties pledged under the facility. At December 31, 2002, the borrowing base was $56.0 million with no further scheduled borrowing base reduction. If our outstanding balance exceeds our borrowing base at any time, we are required to repay such excess within 30 days and our interest rate during the time an excess exists is increased by 2.00%.

On March 25, 2003, we entered into an agreement with our lenders to defer our scheduled borrowing base redetermination until the next scheduled redetermination in May 2003. This agreement reaffirmed the current borrowing base of $56.0 million and the borrowing base reduction amount of zero. As part of this agreement we committed to reduce the amount outstanding under our borrowing base by $6.0 million between March 28, 2003 and May 31, 2003. Additionally, if the aggregate principal amount of the loan exceeds the required month-end reductions of $1.5 million, $2.5 million and $2.0 million during the period from March 28, 2003 to May 31, 2003, such principal amounts in excess of the applicable period limits shall bear interest at a per annum rate of interest equal to the adjusted reference rate plus 2%. Further, the lenders agreed to raise the limit of advances available to be made to our foreign subsidiaries and specified certain future events which would require our foreign subsidiaries to return the incremental advances to the parent. On March 28, 2003, we made a payment of $1.5 million reducing our outstanding principal to $54.5 million. At the next scheduled redetermination in May 2003, the lenders can increase or decrease the borrowing base and re-establish the monthly reduction amount. A material reduction in the borrowing base or a material increase in the monthly reduction amount by the lender would have a material negative impact on our cash flows and our ability to fund future operations.

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 0.25%, 0.50%, 0.75% or 1.00% depending on the amount outstanding under the credit agreement. The interest on a Eurodollar loan is equal to the Eurodollar rate, plus a margin of 2.25%, 2.50%, 2.875%, or 3.125% depending on the amount outstanding under the credit facility. The credit facility matures in May 2004. Our credit facility contains conditions and restrictive provisions, among other things, (1) limiting us to enter into any arrangement to sell or transfer any of our material property, (2) prohibiting a merger into or consolidation with any other person or sell or dispose of all or substantially all of our assets, (3) maintaining certain financial ratios and (4) limitations on advances to our foreign subsidiaries.

Note Payable / Effective June 29, 2001, we issued a note payable to a purchaser for a face principal amount of $31.3 million which matures in June 2005 and bears interest at a fixed rate of 11.5% per annum. The note is secured by second priority liens on substantially all of our U.S. oil and gas properties and is subordinated in right of payment to our existing senior indebtedness. We executed an agreement in connection with the note which contains conditions and restrictive provisions and requires the maintenance of certain financial ratios. Upon consent of the purchaser, which shall not be unreasonably withheld, the note may be repaid prior to the maturity date with an additional repayment premium based on the percentage of the principal amount paid, ranging from 4.5% during the first year to 16.5% in the final year of payment. If the note is paid at maturity, the maximum payment premium of 16.5% is required. The expected repayment premium is being amortized to interest expense straight-line, over the term of the note which approximates the effective interest method. The resulting liability is included in other long-term liabilities on the consolidated balance sheet. In July 2001, we received proceeds of $30.0 million in consideration for the issuance of the note. The discount of $1.3 million is being amortized to interest expense using the effective interest method. The amount available for borrowing under the note is limited to the loan value of oil and gas properties pledged under the note, as determined by the purchaser. The purchaser has the right to make a redetermination of the borrowing base at least once every six months. We were not notified of any change in the borrowing base in 2002. If our outstanding balance exceeds the borrowing base at any time, we are required to repay such excess within 10 days subject to the provisions of the agreement. A material reduction in the borrowing base by the lender would have a material negative impact on our cash flows and our ability to fund future obligations. As of December 31, 2002, all of our borrowing base under the agreement was outstanding.

As of December 31, 2002, we were in compliance with all of the financial covenants of our credit facility and note payable agreements.

Working Capital / At December 31, 2002, we had a working capital deficit of approximately $13.7 million, an improvement over our working capital deficit of $29.1 million at December 31, 2001. In compliance with the definition of working capital in our credit facility, which excludes current maturities of long-term debt and the current portion of assets and liabilities from derivatives, we had working capital of approximately $0.3 million at December 31, 2002 as compared to a deficit of approximately $9.0 million at December 31, 2001. We believe the cash flows from operating activities combined with our ability to control the timing of substantially all of our future development and acquisition requirements will provide us with the flexibility and liquidity to meet our future planned capital requirements.

Our 2003 planned development and acquisition programs are projected to be substantially funded by available cash flow from our 2003 operations. We believe the cash flows from operating activities combined with our ability to control the timing of substantially all of our future development and acquisition requirements will provide us with the flexibility and liquidity to meet our future capital requirements. In addition to these measures, we are currently in discussions with potential investors to provide additional capital. These discussions involve increases to our current credit facilities, new credit facilities and the sale of interests in selected properties. We have also explored the possibility of the issuance of new debt or equity. Completion of any of these potential financings would expand our capabilities to further reduce our outstanding indebtedness, improve our working capital position and may allow us to expand or accelerate our future development and acquisition programs. There can be no assurance however, that we will be successful in negotiating any of these transactions or that the form of the transaction will be acceptable to both the potential investor and our management or our board of directors.

Commitments / We have various commitments primarily related to leases for office space, other property and equipment and other agreements. We expect to fund these commitments with cash generated from operations.

The following table summarizes certain contractual obligations at December 31, 2002 (in thousands):

	Payments Due By Period				
Contractual Obligation (1)	Total	Less Than 1 Year	1-2 Years	3-4 Years	After 4 Years
Total debt	$ 87,250	$ 6,000	$ 81,250	$ –	$ –
Interest expense on credit facility (2)	3,971	2,940	1,031	–	–
Interest expense on promissory note (3)	12,332	4,940	7,392	–	–
Non-cancelable operating leases	2,949	539	910	503	997
Contractor commitment (4)	11,146	–	11,146	–	–
Total contractual obligations	$117,648	$14,419	$101,729	$503	$997

(1) *Does not include any amounts related to contingencies discussed below.*

(2) *Includes interest based on rates and monthly reduction amounts in effect at December 31, 2002.*

(3) *Includes 11.5% interest and repayment premium.*

(4) *Includes 12% interest.*

Contingencies / On August 28, 2001 ATP entered into a written agreement to acquire a property in the Gulf of Mexico during September 2001. On October 9, 2001 the agreement was amended to ultimately extend the closing date until October 31, 2001 in exchange for payments made by ATP totaling $3.0 million. This amendment also contained an arrangement whereby if ATP did not close on the property, and if sellers sold the property to a third party with a sale that met specific contract requirements, ATP would be required to execute a six month note for payment of the differential. Since ATP did not obtain the financing for the acquisition by October 31, 2001, the transaction did not close by that date; however, the parties' intensive work toward closing continued beyond that date without interruption.

While working on the closing for the property with ATP, the sellers sold the property to a third party without informing ATP until after the closing had taken place. ATP filed an action in the District Court of Harris County, Texas against the sellers, generally alleging improper sale of the offshore property to a third party and breach of contract, and seeking unspecified damages from the sellers. The case is encaptioned *ATP Oil & Gas Corporation vs. Legacy Resources Co., L.P. et al,* No. 2001-63224 in the 269th Judicial District Court of Harris County, Texas. At the same time sellers notified ATP of their sale to a third party, the sellers had a demand made upon ATP for execution of a six month note for the amount of an alleged differential of approximately $12.3 million plus interest at 16%. Substantiation of the amount and validity of the demand could not be ascertained based on the content of the demand received. ATP contested the entire demand. The judge has abated the litigation, until arbitration pursuant to the underlying agreements between the sellers and ATP is completed. A tentative date of May 19, 2003 has been scheduled for the arbitration with an alternative date in September 2003. Due to the inherent uncertainties involving contested facts and legal issues a prediction as to the likely outcome cannot be made with any degree of certainty, and we have not accrued any amount related to this matter. While we are seeking recovery of the amounts previously paid and discussed above, the $3.0 million has been charged to earnings along with other costs related to this matter. ATP intends to vigorously defend against the sellers' claims and forcefully pursue its own claims in this matter.

In August 2001, Burlington Resources Inc. filed suit against ATP alleging formation of a contract with ATP and our breach of the alleged contract. The complaint seeks compensatory damages of approximately $1.1 million. We believe that this claim is without merit, and we intend to defend it vigorously.

In 2001 we purchased three properties in the U.K. Sector – North Sea for approximately $3.1 million. In accordance with the purchase agreement, we also committed to pay future consideration contingent upon the successful development and operation of the properties. The contingent consideration for each property includes amounts to be paid upon achieving first commercial production and upon achieving designated cumulative production levels. Active development is in progress on our Helvellyn property and future development is planned on the other two properties. First commercial production from the Helvellyn property may occur sometime in the first half of 2003. Although a significant portion of the work required has been completed, there remains significant additional work to be performed before this property can produce commercially. That work includes completion, hook-up, and testing of the pipeline and production facilities and final negotiation of certain terms in our transportation and processing agreements. Accordingly, there can be no assurance of eventual production from this development until the aforementioned activities are completed successfully. At such time, the required amount will be accrued for payment to the seller and capitalized as acquisition costs.

We are also, in the ordinary course of business, a claimant and/or defendant in various legal proceedings. Management does not believe that the outcome of these legal proceedings, individually, and in the aggregate will have a materially adverse effect on our financial condition, results of operations or cash flows.

RECENT ACCOUNTING PRONOUNCEMENTS

In June 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 143 *"Accounting for Asset Retirement Obligations"* ("SFAS 143"). SFAS 143 provides accounting requirements for retirement obligations associated with tangible long-lived assets, including: 1) the timing of liability recognition; 2) initial measurement of the liability; 3) allocation of asset retirement cost to expense; 4) subsequent measurement of the liability; and 5) financial statement disclosures. SFAS 143 requires that an asset retirement cost should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The statement is effective for fiscal years beginning after June 15, 2002 and we adopted the statement on January 1, 2003. The transition adjustment resulting from the adoption of SFAS 143 will be reported as a cumulative effect of a change in accounting principle. We have not yet completed our assessment of the impact of SFAS 143 on our financial condition and results of operations. However, we expect that adoption of the statement will result in increases in the capitalized costs of our oil and properties and in the recognition of additional liabilities related to asset retirement obligations.

In April 2002, the FASB issued SFAS No. 145, *"Rescission of FASB Statements No. 4, No. 44, and No. 64, Amendment of FASB Statement No. 13, and Technical Corrections"* ("SFAS 145"). Among other things, SFAS 145 requires gains and losses from early extinguishment of debt to be included in income from continuing operations instead of being classified as extraordinary items as previously required by generally accepted accounting principles. SFAS 145 is effective for fiscal years beginning after May 15, 2002 and we adopted the statement on January 1, 2003. Any gain or loss on early extinguishment of debt that was classified as an extraordinary item in periods prior to adoption must be reclassified into income from continuing operations. The adoption of SFAS 145 will require the $0.6 million (net of tax) of extraordinary loss for the year ended December 31, 2001 to be reclassified to interest expense and income tax benefit.

In June 2002, the FASB issued SFAS No. 146, *"Accounting for Costs Associated with Exit or Disposal Activities"* ("SFAS 146"). SFAS 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullified Emerging Issues Task Force Issue No. 94-3, *"Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring"*. SFAS 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. SFAS 146 also establishes that fair value is the objective for initial measurement of the liability. The provisions of this statement are effective for exit or disposal activities that are initiated after December 31, 2002. We adopted the provisions of SFAS 146 on January 1, 2003 and the adoption did not have an effect on our financial position or results of operations.

In December 2002, the FASB issued SFAS No. 148, *"Accounting for Stock-Based Compensation – Transition and Disclosure an amendment of FASB Statement No. 12"* ("SFAS 148"). This statement amends SFAS No. 123, *"Accounting for Stock-Based Compensation"* ("SFAS 123"), to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation. It also amends the disclosure provisions of that statement to require prominent disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation. Finally, this statement amends Accounting Principles Board Opinion No. 28, "Interim Financial Reporting" ("APB 28"), to require disclosure about those effects in interim financial information. We intend to continue to account for stock-based compensation based on the provisions of APB Opinion No. 25. The amended disclosure requirements have been incorporated in Note 2 to the Consolidated Financial Statements.

In November 2002, the FASB issued FASB Interpretation No. 45 *"Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantee of Indebtedness of Others"* ("FIN 45"). FIN 45 requires that upon issuance of a guarantee, the guarantor must recognize a liability for the fair value of the obligation it assumes under that guarantee. FIN 45's provisions for initial recognition and measurement should be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure provisions apply to financial statements for periods ending after December 15, 2002. We do not currently have guarantees that require disclosure. We adopted the measurement provisions of this statement in the first quarter of 2003 and the adoption did not have an effect on our financial position or results of operations.

In January 2003, the FASB issued FASB Interpretation No. 46, *"Consolidation of Variable Interest Entities"* ("FIN 46"). FIN 46 requires a company to consolidate a variable interest entity if it is designated as the primary beneficiary of that entity even if the company does not have a majority of voting interest. A variable interest entity is generally defined as an entity where its equity is unable to finance its activities or where the owners of the entity lack the risk and rewards of ownership. The provisions of FIN 46 apply immediately to variable interest entities created after January 31, 2003 and to variable interest entities in which an enterprise obtains an interest after that date. The adoption of FIN 46 is not currently expected to have an effect on our financial position or results of operations when adopted.

Emerging Issues Task Force ("EITF") Issue No. 02-03, *"Recognition and Reporting of Gains and Losses on Energy Trading Contracts"* under EITF Issues No. 98-10, *"Accounting for Contracts Involved in Energy Trading and Risk Management Activities"* was issued in June 2002. EITF Issue No. 02-03 addresses certain issues related to energy trading activities, including (a) gross versus net presentation in the income statement, (b) whether the initial fair value of an energy trading contract can be other than the price at which it was exchanged, and (c) accounting for inventory utilized in energy trading activities. As of January 1, 2003, we will present our gas sold and purchased activities in the statement of operations for all periods on a net rather than a gross basis. The change will decrease reported revenues and costs and operating expenses, but will have no effect on operating income or cash flow. The remaining provisions effective January 1, 2003 will have no impact on our financial statements. For more information regarding this marketing activity, see Note 13 to the Consolidated Financial Statements.

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 facility. Under our current policies, we do not use interest rate derivative instruments to manage exposure to interest rate changes.

Foreign Currency Risk / The net assets, net earnings and cash flows from our wholly owned subsidiary in the U.K. are based on the U.S. dollar equivalent of such amounts measured in the applicable functional currency. These foreign operations have the potential to impact our financial position due to fluctuations in the local currency arising from the process of re-measuring the local functional currency in the U.S. dollar. We have not utilized derivatives or other financial instruments to hedge the risk associated with the movement in foreign currencies.

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 a portion of our natural gas and oil production under price sensitive or market price contracts. We periodically use derivative instruments to hedge our commodity price risk. We hedge a portion of our projected natural gas and oil production through a variety of financial and physical arrangements intended to support natural gas and oil prices at targeted levels and to manage our exposure to price fluctuations. We may use futures contracts, swaps and fixed price physical contracts to hedge our commodity prices. Realized gains and losses from our price risk management activities are recognized in oil and gas sales when the associated production occurs. For derivatives designated as cash flow hedges, the unrecognized gains and losses are included as a component of other comprehensive income (loss) to the extent the hedge is effective. See Note 12 to the Consolidated Financial Statements for additional information. We do not hold or issue derivative instruments for trading purposes.

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 management's estimated value of the estimated proved reserves at the then current natural gas and oil prices. We may enter into short-term hedging arrangements if (1) 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 or (2) if deemed necessary by the terms of our existing credit agreements. During 2002, we hedged approximately 51% of our natural gas and oil production.

To calculate the potential effect of the derivative and fixed-price contracts on future income (loss) before taxes, we applied the NYMEX oil and gas strip prices as of December 31, 2002 to the quantity of our oil and gas production covered by those contracts as of that date. The following table shows the estimated potential effects of the derivative and fixed-price contracts on future income (loss) before taxes (in thousands):

	Estimated Increase (Decrease) In Income (Loss) Before Taxes Due to	
Instrument	10% Decrease in Prices	10% Increase in Prices
Natural gas swaps	$2,772	$(2,772)
Oil swaps	504	(504)
Natural gas fixed price contracts	2,374	(2,374)
Oil fixed price contracts	642	(642)

REPORT OF MANAGEMENT

The consolidated financial statements of ATP Oil & Gas Corporation and subsidiary and the related information included in this Annual Report have been prepared by management in conformity with accounting principles generally accepted in the United States of America. The financial statements include certain estimates and judgments which management believes are reasonable under the circumstances.

Management maintains a system of internal control including internal accounting controls that provide management with reasonable assurance that our assets are protected and that published financial statements are reliable and free of material misstatement. Management is responsible for the effectiveness of internal controls. This is accomplished through established codes of conduct, accounting and other control systems, policies and procedures, employee selection and training, appropriate delegation of authority and segregation of responsibilities.

The Audit Committee of the Board of Directors, composed solely of directors who are not officers or employees, meets periodically with the independent certified accountants, financial management and counsel. To ensure complete independence, the certified public accountants have full and free access to the Audit Committee to discuss the results of their audits, the adequacy of internal controls and the quality of financial reporting.

Our independent certified public accountants provide an objective independent review by their audit of the Company's financial statements. Their audit is conducted in accordance with generally accepted auditing standards and includes a review of the system of internal accounting controls to the extent deemed necessary for the purpose of their audit.

T. Paul Bulmahn
Chairman & President

Albert L. Reese, Jr.
Senior Vice President & CFO

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, 2002 and 2001, and the related consolidated statements of operations, shareholders' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2002. 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, 2002 and 2001, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for derivative financial instruments.

KPMG LLP

KPMG LLP

Houston, Texas
March 26, 2003

CONSOLIDATED BALANCE SHEETS

	December 31,	
	2002	2001
(In Thousands, Except Share Amounts)		
Assets		
Current assets:		
Cash and cash equivalents	$ 6,944	$ 5,294
Restricted cash	414	-
Accounts receivable (net of allowance of $1,266 and $1,423, respectively)	24,998	10,371
Deferred tax asset	1,628	-
Derivative asset	-	1,936
Other current assets	3,245	1,754
Total current assets	37,229	19,355
Oil and gas properties (using the successful efforts method of accounting)	355,088	319,506
Less: Accumulated depletion, impairment and amortization	(236,052)	(186,473)
Oil and gas properties, net	119,036	133,033
Furniture and fixtures (net of accumulated depreciation)	810	794
Deferred tax asset	21,580	19,228
Other assets, net	3,400	5,154
Total assets	$ 182,055	$ 177,564
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accruals	$ 35,336	$ 26,426
Current maturities of long-term debt	6,000	22,000
Derivative liability	9,592	-
Total current liabilities	50,928	48,426
Long-term debt	80,387	78,111
Long-term derivative liability	-	671
Deferred revenue	1,111	1,296
Other long-term liabilities and deferred obligations	11,082	4,068
Total liabilities	143,508	132,572
Commitments and Contingencies		
Shareholders' equity:		
Preferred stock: $0.001 par value, 10,000,000 shares authorized; none issued	-	-
Common stock: $0.001 par value, 100,000,000 shares authorized in December 31, 2002 and 2001	20	20
Additional paid in capital	81,087	80,478
Accumulated deficit	(39,314)	(34,614)
Accumulated other comprehensive income (loss)	(2,335)	19
Treasury stock, at cost	(911)	(911)
Total shareholders' equity	38,547	44,992
Total liabilities and shareholders' equity	$ 182,055	$ 177,564

See accompanying notes to the consolidated financial statements.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2002	2001	2000
(In Thousands, Except Per Share Amounts)			
Revenues:			
Oil and gas production	$ 88,151	$105,757	$ 75,940
Gas sold – marketing	6,272	7,417	8,015
Gain on sale of oil and gas properties	–	–	33
	94,423	113,174	83,988
Costs and operating expenses:			
Lease operating expenses	16,764	14,806	11,559
Gas purchased – marketing	6,087	7,218	7,788
Geological and geophysical expenses	154	1,068	–
General and administrative expenses	10,287	9,981	5,409
Non-cash compensation expense (general and administrative)	595	3,364	–
Depreciation, depletion and amortization	43,390	53,428	40,569
Impairment of oil and gas properties	6,844	24,891	10,838
Loss on unsuccessful property acquisition	–	3,147	–
Other expense	–	–	450
	84,121	117,903	76,613
Income (loss) from operations	10,302	(4,729)	7,375
Other income (expense):			
Interest income	73	884	451
Interest expense	(10,418)	(10,039)	(11,907)
Other	1,081	–	–
Loss on derivative instruments	(8,319)	(18,083)	(11,911)
	(17,583)	(27,238)	(23,367)
Loss before income taxes and extraordinary item	(7,281)	(31,967)	(15,992)
Income tax benefit	2,581	11,186	5,594
Loss before extraordinary item	(4,700)	(20,781)	(10,398)
Extraordinary item, net of tax	–	(602)	–
Net loss	(4,700)	(21,383)	(10,398)
Other comprehensive income (loss):			
Cumulative effect of change in accounting principle	–	(34,252)	–
Reclassification adjustment for settled contracts	627	34,252	–
Change in fair value of outstanding hedging positions	(3,651)	–	–
Foreign currency translation adjustment	670	19	–
Other comprehensive income (loss)	(2,354)	19	–
Comprehensive loss	$ (7,054)	$ (21,364)	$(10,398)
Basic and diluted loss per common share:			
Loss before extraordinary item	$ (0.23)	$ (1.06)	$ (0.73)
Extraordinary item, net of tax	–	(0.03)	–
Net loss per common share	$ (0.23)	$ (1.09)	$ (0.73)
Weighted average number of common shares:			
Basic and diluted	20,315	19,704	14,286

See accompanying notes to the consolidated financial statements.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In Thousands)	2002	2001	2000
	Years Ended December 31,		
Cash flows from operating activities:			
Net loss	$ (4,700)	$ (21,383)	$(10,398)
Adjustments to reconcile net loss to net cash provided by operating activities –			
Depreciation, depletion and amortization	43,390	53,428	40,569
Impairment of oil and gas properties	6,844	24,891	10,838
Amortization of deferred financing costs	1,429	797	376
Extraordinary item	–	926	–
Other comprehensive loss	(3,024)	–	–
Deferred tax assets	(2,352)	(11,576)	(5,594)
Non-cash compensation expense	595	3,364	–
Gain on sale of oil and gas properties	–	–	(33)
Other expense	–	–	450
Other non-cash items	746	196	431
Changes in assets and liabilities –			
Accounts receivable and other	(14,659)	23,014	(22,772)
Restricted cash	(414)	–	471
Net (assets) liabilities from risk management activities	9,229	(8,513)	7,249
Accounts payable and accruals	8,910	(23,436)	37,309
Other long-term assets	(1,525)	(4,183)	(1,462)
Other long-term liabilities and deferred credits	6,829	3,831	(277)
Net cash provided by operating activities	51,298	41,356	57,157
Cash flows from investing activities:			
Additions and acquisitions of oil and gas properties	(34,873)	(110,264)	(76,474)
Additions to furniture and fixtures	(294)	(546)	(361)
Net cash used in investing activities	(35,167)	(110,810)	(76,835)
Cash flows from financing activities:			
Proceeds of initial public offering	–	78,330	–
Payment of offering costs	–	(893)	(621)
Proceeds from long-term debt	1,000	119,000	15,800
Payments of long-term debt	(15,000)	(46,750)	(8,250)
Proceeds from non-recourse borrowings	–	3,359	42,745
Payments of non-recourse borrowings	–	(92,138)	(29,239)
Deferred financing costs	(495)	(3,586)	(400)
Treasury stock purchases	–	(911)	–
Other	14	201	–
Net cash provided by (used in) financing activities	(14,481)	56,612	20,035
Increase (decrease) in cash and cash equivalents	1,650	(12,842)	357
Cash and cash equivalents, beginning of period	5,294	18,136	17,779
Cash and cash equivalents, end of period	$ 6,944	$ 5,294	$ 18,136
Supplemental disclosures of cash flow information:			
Cash paid during the period for interest	$ 7,361	$ 4,177	$ 2,531
Cash paid during the period for taxes	$ –	$ –	$ 497

See accompanying notes to the consolidated financial statements.

ATP OIL & GAS CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (DEFICIT)

	2002		2001		2000	
	Shares	Amount	Shares	Amount	Shares	Amount
(In Thousands)						
Common Stock						
Balance, beginning of year	20,313	$ 20	14,286	$ 14	14,286	$ 14
Issuances of common stock						
Public offering	–	–	6,000	6	–	–
Exercise of stock options	9	–	103	–	–	–
Purchase of treasury stock	–	–	(76)	–	–	–
Balance, end of year	20,322	$ 20	20,313	$ 20	14,286	$ 14
Paid-in Capital						
Balance, beginning of year		$ 80,478		$ 38		$ 38
Issuances of common stock						
Public offering			–	76,809		–
Exercise of stock options		14		267		–
Non-cash compensation expense		595		3,364		–
Balance, end of year		$ 81,087		$ 80,478		$ 38
Accumulated Deficit						
Balance, beginning of year		$(34,614)		$(13,231)		$ (2,833)
Net loss		(4,700)		(21,383)		(10,398)
Balance, end of year		$(39,314)		$(34,614)		$(13,231)
Accumulated Other Comprehensive Income (Loss)						
Balance, beginning of year		$ 19		$ –		$ –
Other comprehensive income (loss)		(2,354)		19		–
Balance, end of year		$ (2,335)		$ 19		$ –
Treasury Stock						
Balance, beginning of year	76	$ (911)	–	$ –	–	$ –
Purchase of treasury stock	–	–	76	(911)	–	–
Balance, end of year	76	$ (911)	76	$ (911)	–	$ –
Total Shareholders' Equity (Deficit)		$ 38,547		$ 44,992		$(13,179)

See accompanying notes to the consolidated financial statements.

NOTE 1 – ORGANIZATION AND BASIS OF PRESENTATION

Organization / 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 Gulf of Mexico and the U.K. and Dutch Sectors of the North Sea (the "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 rate of return on our investment in these properties by limiting our up-front acquisition costs and by developing our acquisitions quickly.

Basis of Presentation / The consolidated financial statements include our accounts and our wholly-owned subsidiaries, ATP Energy, Inc. (ATP Energy), ATP Oil & Gas (UK) Limited and ATP Oil & Gas Netherlands (B.V.). All significant intercompany transactions are eliminated upon consolidation. Certain reclassifications have been made to the prior year statements to conform to the current year presentation.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

Use of Estimates / The preparation of financial statements in accordance with generally accepted accounting principles and pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC") requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosure of contingent assets and liabilities in the financial statements, 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.

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.

Oil and Gas Producing Activities / We follow 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 geological and geophysical data are generally charged to expense unless the costs can be specifically attributed to determining the placement for a future developmental well location.

Expenditures for repairs and maintenance are charged to expense as incurred; renewals and betterments are capitalized. The costs and related accumulated depreciation, depletion, and amortization of properties sold or otherwise retired are eliminated from the accounts, and gains or losses on disposition are reflected in the statements of operations.

We perform 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 in accordance with Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standard ("SFAS") No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets"* ("SFAS 144"). To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management's estimates of future oil and gas prices to the estimated future production of oil and gas reserves over the economic life of the property. Future net cash flows are based upon our independent reservoir 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 or other development activities. For a property determined to be impaired, an impairment loss equal to the difference between the carrying value and the estimated fair value of the impaired property will be recognized. Fair value, on a depletable unit basis, is estimated to be the present value of the aforementioned expected future net cash flows. Any impairment charge incurred is recorded in accumulated depreciation, depletion, impairment and amortization to reduce our recorded basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units' reserves, future cash flows and fair value. We recorded impairments during the years ended December 31, 2002, 2001 and 2000 of $6.8 million, $24.9 million and $10.8 million, respectively, primarily due to either depressed oil and natural gas prices, unfavorable operating performance or downward revisions of recoverable reserves or a combination of all. The impairments were calculated as the difference between the carrying value and the estimated fair value of the impaired depletable unit.

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 five years.

Other Assets / Other assets consist of the following (in thousands):

	December 31,	
	2002	2001
Debt financing costs	$ 3,767	$3,584
Spare parts inventory	1,000	2,138
Long-term portion of receivable	629	–
Other	10	9
	5,406	5,731
Accumulated amortization	(2,006)	(577)
	$ 3,400	$5,154

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized to interest expense over the term of the related agreement, using the effective interest or straight-line method (which approximates the effective interest method).

Environmental Liabilities / Environmental liabilities are recognized when the expenditures are considered probable and can be reasonably estimated. Measurement of liabilities is based on currently enacted laws and regulations, existing technology and undiscounted site-specific costs. Generally, such recognition coincides with our commitment to a formal plan of action.

Revenue Recognition / We use the sales method of accounting for natural gas and oil revenues. Under this method, revenues are recognized based on actual volumes of gas and oil sold to purchasers. The volumes sold may differ from the volumes to which we are entitled based on our interests in the properties. Differences between volumes sold and entitled volumes create gas imbalances which are generally reflected as adjustments to reported proved gas reserves and future cash flows in the our supplemental oil and gas disclosures. Adjustments for gas imbalances totaled approximately 0.25 percent of our proved gas reserves at December 31, 2002. If our excess takes of natural gas or oil exceed our estimated remaining proved reserves for a property, a natural gas or oil imbalance liability is recorded in the consolidated balance sheet. No such amount was recorded in 2002.

Major Customers / We sell a portion of our oil and gas to end users through various gas marketing companies. For the year ended December 31, 2002, revenues from four purchasers accounted for 34%, 26%, 14% and 14%, respectively, for oil and gas production revenues. For the year ended December 31, 2001, revenues from three purchasers accounted for 53%, 17% and 10%, respectively, of oil and gas production revenues. For the year ended December 31, 2000, revenues from two purchasers accounted for 41% each of oil and gas production revenues. Percentages are calculated on oil and gas revenues before any effects of price risk management activities.

Translation of Foreign Currencies / Financial statement amounts related to our U.K. subsidiary, which has a functional currency of the British pound sterling, are translated into the U.S. dollar equivalents at exchange rates as follows: (1) balance sheet accounts at year-end exchange rates and (2) statement of operations accounts at the weighted average exchange rate for the period. The gains or losses resulting from such translations are deferred and included in accumulated other comprehensive income as a separate component of shareholders' equity.

Income Taxes / Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences or benefits attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes that enactment date.

Comprehensive Loss / Comprehensive loss is net loss, plus certain other items that are recorded directly to shareholders' equity. In 2002 and 2001, comprehensive loss was $7.1 million and $21.4 million, respectively. In 2000, we had no comprehensive income (loss) other than net loss.

Stock Options / At December 31, 2002, we had stock-based compensation plans which are more fully described in Note 6. We account for these plans under the recognition and measurement principles of Accounting Principles Board Opinion No. 25, *"Accounting for Stock Issued to Employees"* ("APB 25") and related interpretations. Under APB 25, no compensation expense is recognized when the exercise price of options equals the fair value (market price) of the underlying stock on the date of grant. The following table illustrates the effect on net income and earnings per share if we had applied the fair value recognition provisions of SFAS No. 123 *"Accounting for Stock Based Compensation"* ("SFAS 123") to stock based compensation:

	Year Ended December 31,	
	2002	2001
Net loss before extraordinary item, as reported	$(4,700)	$(20,781)
Add: Stock based employee compensation expense included in reported net loss, determined under APB 25, net of related tax effects	387	2,187
Deduct: Total stock based employee compensation expense determined under fair value for all awards, net of related tax effects	(2,673)	(3,517)
Pro forma net loss before extraordinary item	$(6,986)	$(22,111)
Earnings per share:		
Basic and diluted – as reported	$ (0.23)	$ (1.06)
Basic and diluted – pro forma	$ (0.34)	$ (1.12)

Fair Value of Financial Instruments / The following methods and assumptions were used in estimating the fair value of each class of financial instruments for which it is practicable to estimate fair value.

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

As of January 1, 2001, we adopted SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities"* ("SFAS 133"), as amended. SFAS 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and hedging activities. It requires the recognition of all derivative instruments as assets or liabilities in our balance sheet and measurement of those instruments at fair value. The accounting treatment of changes in fair value is dependent upon whether or not a derivative instrument is designated as a hedge and if so, the type of hedge. For derivatives designated as cash flow hedges, changes in fair value are recognized in other comprehensive income (loss) to the extent the hedge is effective, until the hedged item is recognized in earnings. Hedge effectiveness is measured quarterly based on the relative changes in fair value between the derivative instrument and the hedged item over time. Any change in fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in earnings.

The following table provides information on our debt (in thousands):

	December 31,			
	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Bank debt	$56,000	$56,000	$ 70,000	$ 70,000
Note payable	30,387	34,376	30,111	33,400
Total	$86,387	$90,376	$100,111	$103,400

Our bank debt is variable rate debt and as such, approximates fair values, as interest rates are variable based on prevailing market rates. Our note payable is a fixed rate note and the fair value has been determined by discounting the future payments using our incremental borrowing rate, based on the differential between the fixed interest rate and interest rates of long-term treasury securities at the date of the borrowing and the balance sheet date.

New Accounting Standards / In June 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 143 *"Accounting for Asset Retirement Obligations"* ("SFAS 143"). SFAS 143 provides accounting requirements for retirement obligations associated with tangible long-lived assets, including: 1) the timing of liability recognition; 2) initial measurement of the liability; 3) allocation of asset retirement cost to expense; 4) subsequent measurement of the liability; and 5) financial statement disclosures. SFAS 143 requires that an asset retirement cost should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The statement is effective for fiscal years beginning after June 15, 2002 and we adopted the statement on January 1, 2003. The transition adjustment resulting from the adoption of SFAS 143 will be reported as a cumulative effect of a change in accounting principle. We have not yet completed our assessment of the impact of SFAS 143 on our financial condition and results of operations. However, we expect that adoption of the statement will result in increases in the capitalized costs of our oil and properties and in the recognition of additional liabilities related to asset retirement obligations.

In April 2002, the FASB issued SFAS No. 145, *"Rescission of FASB Statements No. 4, No. 44, and No. 64, Amendment of FASB Statement No. 13, and Technical Corrections"* ("SFAS 145"). Among other things, SFAS 145 requires gains and losses from early extinguishment of debt to be included in income from continuing operations instead of being classified as extraordinary items as previously required by generally accepted accounting principles. SFAS 145 is effective for fiscal years beginning after May 15, 2002 and we adopted the statement on January 1, 2003. Any gain or loss on early extinguishment of debt that was classified as an extraordinary item in periods prior to adoption must be reclassified into income from continuing operations. The adoption of SFAS 145 will require the $0.6 million (net of tax) of extraordinary loss for the year ended December 31, 2001 to be reclassified to interest expense and income tax benefit.

In June 2002, the FASB issued SFAS No. 146, *"Accounting for Costs Associated with Exit or Disposal Activities"* ("SFAS 146"). SFAS 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullified Emerging Issues Task Force Issue No. 94-3, *"Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring"*. SFAS 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. SFAS 146 also establishes that fair value is the objective for initial measurement of the liability. The provisions of this statement are effective for exit or disposal activities that are initiated after December 31, 2002. We adopted the provisions of SFAS 146 on January 1, 2003 and the adoption did not have an effect on our financial position or results of operations.

In November 2002, the FASB issued FASB Interpretation No. 45 *"Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantee of Indebtedness of Others"* ("FIN 45"). FIN 45 requires that upon issuance of a guarantee, the guarantor must recognize a liability for the fair value of the obligation it assumes under that guarantee. FIN 45's provisions for initial recognition and measurement should be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure provisions apply to financial statements for periods ending after December 15, 2002. We do not currently have guarantees that require disclosure. We will adopt the measurement provisions of this statement in the first quarter of 2003 and the adoption is not expected to have a material effect on our financial position or results of operations.

In January 2003, the FASB issued FASB Interpretation No. 46, *"Consolidation of Variable Interest Entities"* ("FIN 46"). FIN 46 requires a company to consolidate a variable interest entity if it is designated as the primary beneficiary of that entity even if the company does not have a majority of voting interest. A variable interest entity is generally defined as an entity where its equity is unable to finance its activities or where the owners of the entity lack the risk and rewards of ownership. The provisions of FIN 46 apply immediately to variable interest entities created after January 31, 2003 and to variable interest entities in which an enterprise obtains an interest after that date. The adoption of FIN 46 is not currently expected to have an effect on our financial position or results of operations when adopted.

Emerging Issues Task Force ("EITF") Issue No. 02-03, *"Recognition and Reporting of Gains and Losses on Energy Trading Contracts"* under EITF Issues No. 98-10, *"Accounting for Contracts Involved in Energy Trading and Risk Management Activities"* was issued in June 2002. EITF Issue No. 02-03 addresses certain issues related to energy trading activities, including (a) gross versus net presentation in the income statement, (b) whether the initial fair value of an energy trading contract can be other than the price at which it was exchanged, and (c) accounting for inventory utilized in energy trading activities. As of January 1, 2003, we will present our gas sold and purchased activities in the statement of operations for all periods on a net rather than a gross basis. The change will decrease reported revenues and costs and operating expenses, but will have no effect on operating income or cash flow. The remaining provisions effective January 1, 2003 will have no impact on our financial statements. For more information regarding this marketing activity, see Note 13.

NOTE 3 – ACQUISITIONS AND DISPOSITIONS

Gulf of Mexico / During 2002, we entered into a farm-in agreement to acquire a 100% working interest in one block with associated proved reserves of approximately 4.7 Bcf (unaudited), based on third party reservoir engineering estimates at year-end. We plan to develop this block in 2003.

In addition, we acquired another block for approximately $1.0 million. This block, along with the block immediately to the south which we did not acquire, contains an accumulation of oil and gas. Since the well that identified proved reserves is located on the southern block and due to the strict limitations to declare reserves as proved, we are unable to record any proved reserves with this acquisition. The costs of this unproved property is included in oil and gas properties at December 31, 2002.

U.K. Sector – North Sea / In 2001, we acquired interests in three properties (five blocks) in the North Sea which included a 100% interest in one block ("Helvellyn"), a 50% interest in one block ("Venture") and an 86% interest in three blocks ("Tors"). We are the operator of all of these blocks.

Helvellyn / In August 2002 we entered into an agreement, which was completed on September 30, 2002, whereby we assigned 50% of our working interest in the Helvellyn development in the U.K. Sector – North Sea to a joint venture partner. The terms of the agreement required the other party to pay a disproportionate share of the development costs on the project. The partner's share of development costs totaled $28.9 million through December 31, 2002, of which $17.3 million was paid to us in cash, $11.0 million is included in accounts receivable and $0.6 million is included as a receivable in other long term assets. We retained a 50% working interest and continued as the operator of the field.

Tors / In February 2002 the U.K. Department of Trade and Industry directly awarded us a 75% working interest in two lease blocks. The lease sale in the U.K. is referred to as a "round" and the award is known as an "out of round" award. We paid no acquisition costs and net proved reserves for these properties at December 31, 2002, were approximately 20.3 Bcf (unaudited), based on third party reservoir engineering estimates at year-end. These two blocks will become a component of our Tors development.

In October 2002 we entered into an earn-in agreement whereby we assigned an 11% interest in three blocks acquired in 2001 to a joint venture partner in return for them funding part of the block's development costs. We retained a 75% working interest and continued as the operator of the block. As of December 31, 2002, these blocks had not yet been developed.

Dutch Sector – North Sea / In February 2003, we acquired a 50% working interest in a block located in the Dutch Sector – North Sea. The remaining 50% interest is owned by a Dutch company who participates on behalf of the Dutch state.

NOTE 4 - FINANCING AND DEBT

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

	December 31, 2002	December 31, 2001
Credit facility, bearing interest at 5.25% and 5.26% at December 31, 2002 and 2001, respectively	$56,000	$ 70,000
11.5 % Note payable, net of unamortized discount of $863 and $1,139 at December 31, 2002 and 2001, respectively	30,387	30,111
Total debt	86,387	100,111
Less current maturities	(6,000)	(22,000)
Total long-term debt	$80,387	$ 78,111

Credit Facility / We have a $100.0 million senior-secured revolving credit facility which is secured by substantially all of our U.S. oil and gas properties, as well as by approximately two-thirds of the capital stock of our foreign subsidiaries and is guaranteed by our wholly owned subsidiary, ATP Energy, Inc. The amount available for borrowing under the credit facility is limited to the loan value, as determined by the bank, of oil and gas properties pledged under the facility. At December 31, 2002, the borrowing base was $56.0 million with no further scheduled borrowing base reduction. If our outstanding balance exceeds our borrowing base at any time, we are required to repay such excess within 30 days and our interest rate during the time an excess exists is increased by 2.00%.

On March 25, 2003, we entered into an agreement with our lenders to defer our scheduled borrowing base redetermination until the next scheduled redetermination in May 2003. This agreement reaffirmed the current borrowing base of $56.0 million and the borrowing base reduction amount of zero. As part of this agreement we committed to reduce the amount outstanding under our borrowing base by $6.0 million between March 28, 2003 and May 31, 2003. Additionally, if the aggregate principal amount of the loan exceeds the required month-end reductions of $1.5 million, $2.5 million and $2.0 million during the period from March 28, 2003 to May 31, 2003, such principal amounts in excess of the applicable period limits shall bear interest at a per annum rate of interest equal to the adjusted reference rate plus 2%. Further, the lenders agreed to raise the limit of advances available to be made to our foreign subsidiaries and specified certain future events which would require our foreign subsidiaries to return the incremental advances to the parent. At the next scheduled redetermination in May 2003, the lenders can increase or decrease the borrowing base and re-establish the monthly reduction amount. A material reduction in the borrowing base or a material increase in the monthly reduction amount by the lender would have a material negative impact on our cash flows and our ability to fund future operations.

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 0.25%, 0.50%, 0.75% or 1.00% depending on the amount outstanding under the credit agreement. The interest on a Eurodollar loan is equal to the Eurodollar rate, plus a margin of 2.25%, 2.50%, 2.875%, or 3.125% depending on the amount outstanding under the credit facility. The credit facility matures in May 2004. Our credit facility contains conditions and restrictive provisions, among other things, (1) limiting us to enter into any arrangement to sell or transfer any of our material property, (2) prohibiting a merger into or consolidation with any other person or sell or dispose of all or substantially all of our assets, (3) maintaining certain financial ratios and (4) limitations on advances to our foreign subsidiaries.

Note Payable / Effective June 29, 2001, we issued a note payable to a purchaser for a face principal amount of $31.3 million which matures in June 2005 and bears interest at a fixed rate of 11.5% per annum. The note is secured by second priority liens on substantially all of our U.S. oil and gas properties and is subordinated in right of payment to our existing senior indebtedness. We executed an agreement in connection with the note which contains conditions and restrictive provisions and requires the maintenance of certain financial ratios. Upon consent of the purchaser, which shall not be unreasonably withheld, the note may be repaid prior to the maturity date with an additional repayment premium based on the percentage of the principal amount paid, ranging from 4.5% during the first year to 16.5% in the final year of payment. If the note is paid at maturity, the maximum payment premium of 16.5% is required. The expected repayment premium is being amortized to interest expense straight-line, over the term of the note which approximates the effective interest method. The resulting liability is included in other long-term liabilities on the consolidated balance sheet. In July 2001, we received proceeds of $30.0 million in consideration for the issuance of the note. The discount of $1.3 million is being amortized to interest expense using the effective interest method. The amount available for borrowing under the note is limited to the loan value of oil and gas properties pledged under the note, as determined by the purchaser. The purchaser has the right to make a redetermination of the borrowing base at least once every six months. We were not notified of any change in the borrowing base in 2002. If our outstanding balance exceeds the borrowing base at any time, we are required to repay such excess within 10 days subject to the provisions of the agreement. A material reduction in the borrowing base by the lender would have a material negative impact on our cash flows and our ability to fund future obligations. As of December 31, 2002, all of our borrowing base under the agreement was outstanding.

As of December 31, 2002, we were in compliance with all of the financial covenants of our credit facility and note payable agreements.

Maturities / The aggregate amount of maturities of our long-term debt for the next five years is: 2003 – $6.0 million, 2004 – $50.0 million and 2005 – $31.3 million.

NOTE 5 – EQUITY

Common Stock / At December 31, 2002, we had 100,000,000 shares authorized, 20,398,007 shares issued, 20,322,167 shares outstanding and 75,840 shares in treasury. At December 31, 2001, we had 100,000,000 shares authorized, 20,388,488 shares issued, 20,312,648 shares outstanding and 75,840 shares in treasury.

Treasury Stock / During the second quarter 2001, the first option vesting date occurred for certain options granted since September 1999 through the date of our initial public offering ("IPO") on February 5, 2001, as well as for certain options granted prior to September 1999. Of those options exercised during that period, certain optionees elected to receive cash upon exercise of their options, whereby we purchased 75,840 shares for approximately $0.9 million and recorded such purchase as treasury stock using the cost method.

NOTE 6 – STOCK OPTION PLANS

In May 1994, the Board of Directors approved the 1994 Stock Option Plan (the "1994 Plan") 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 Plan was not less than the greater of par value per share or fair market value, at date of grant. These options had a maximum term of 10 years, subject to vesting requirements in the individual option agreements. In April 2000, the only outstanding option to purchase 18,937,397 shares under the 1994 Plan 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 a majority of the shares, the number of shares exercisable as of April 2000 was zero. Upon the closing of the IPO in February 2001, the 1994 Plan and all outstanding options under this plan were cancelled.

In December 1998, the Board of Directors approved the 1998 Stock Option Plan (the "1998 Plan") to provide increased incentive for its employees and directors. The 1998 Plan authorizes the granting of incentive and nonqualified stock options for up to 2,678,571 shares of common stock to eligible participants and expires five years after the closing date of our IPO. One third of the options were exercisable on April 10, 2001 with each remaining third exercisable on the first and second anniversaries of the IPO. Options granted under this plan remain exercisable by the employees owning such options, but no new options will be granted under this plan.

In January 2001, the Board of Directors approved the 2000 Stock Option Plan (the "2000 Plan") to provide increased incentive for its employees and directors. The 2000 Plan authorizes the granting of options and awards for up to 4,000,000 shares of common stock. Generally, options are granted at prices equal to at least 100% of the fair value of the stock at the date of grant, expire not later than five years from the date of grant and vest ratably over a four-year period following the date of grant. From time to time, as approved by the Board of Directors, options with differing terms have also been granted.

The following table is a summary of stock option activity:

	2002		2001		2000	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	1,637,809	$8.520	646,608	$ 2.710	19,394,362	$0.040
Granted	86,500	3.430	1,117,000	11.200	368,215	3.690
Exercised	(9,519)	1.431	(102,774)	1.960	–	–
Forfeited	(29,643)	9.089	(23,025)	4.000	(178,572)	1.400
Cancelled	–	–	–	–	(18,937,397)	0.004
Outstanding at end of year	1,685,147	$8.290	1,637,809	$ 8.520	646,608	$2.710
Exercisable at end of year	563,344	$6.760	112,760	$ 3.370	–	$ –
Weighted average fair value of options granted during the year	$ 1.74		$ 4.65		$ –	

The following table summarizes information about all stock options outstanding at December 31, 2002:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$ 1.40 – $ 3.85	607,647	2.4 Years	$ 2.94	306,469	$ 3.37
$ 6.95 – $ 6.95	25,000	3.8 Years	6.95	6,250	6.95
$11.24 – $11.40	1,032,500	3.4 Years	11.37	245,625	11.37
$14.00 – $14.00	20,000	3.1 Years	14.00	5,000	14.00
$ 1.40 – $14.00	1,685,147	3.0 Years	$ 8.29	563,344	$ 6.76

We have elected to follow APB 25 and related interpretations in accounting for our stock option plans. Accordingly, no compensation expense, except as specifically described below, has been recognized for employee stock option plans. Since options granted under the 1998 Plan did not vest nor were exercisable until 60 days after the date of our IPO, under the provisions of SFAS No. 123 *"Accounting for Stock Based Compensation"* ("SFAS 123"), our pro forma net loss and per share amounts would have been unchanged for the year ended December 31, 2000. The pro forma effect on net income and earnings per share in 2002 and 2001, had we applied the fair-value-recognition provisions of SFAS 123, are shown in Note 2.

The fair value of options granted in 2002 was estimated at the date of grant using a Black-Scholes option-pricing model with the following weighted-average assumptions: zero dividend yield; risk-free interest rate of 2.8%, volatility of 92.8% and an expected life of 2.5 years.

The fair value of options granted prior to 2002 was estimated on the latter of the date of grant or date of our IPO using a Black-Scholes option-pricing model with the following weighted-average assumptions: zero dividend yield; risk-free interest rate of 4.5% and volatility of 80.2% and an expected life of 2.4 years.

Non-Cash Compensation Expense / In 2002, we recorded a non-cash charge to compensation expense of approximately $0.6 million for options granted since September 1999 through the date of our initial public offering on February 5, 2001 (the "measurement date"). The total expected expense as of the measurement date is recognized in the periods in which the option vests. Each option is divided into three equal portions corresponding to the three vesting dates (April 10, 2001, February 9, 2002, and February 9, 2003), with the related compensation cost for each portion amortized straight-line over the period to the vesting date. In 2001, we recorded a non-cash compensation expense of $2.9 million for the above options and an additional non-cash compensation expense of $0.5 million related to certain options granted prior to September 1999 and exercised during 2001. The additional expense was recorded as a result of the manner in which those shares were exercised.

We have a 401(k) Savings Plan which covers all domestic employees. At our discretion, we may match a certain percentage of the employees' contributions to the plan. The matching percentage is discretionary and is currently 50% of each participant's contributions up to 6% of the participant's compensation. Our matching contributions to the plan were approximately $97,000, $70,000 and $56,000, for the years ended December 31, 2002, 2001 and 2000, respectively.

We also have a defined contribution plan for our U.K. employees. We currently contribute 3% to the plan and such contributions are subject to the Pensions Act 1999 (U.K.) and to U.K. rules on taxation. For the years ended December 31, 2002 and 2001, we contributed approximately $15,500 and $14,000, respectively.

NOTE 7 - EARNINGS PER SHARE

Basic earnings per share is computed by dividing net 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 loss per share is computed based on the following information (in thousands, except per share amounts):

	Years Ended December 31,		
	2002	2001	2000
Net loss available to common shareholders	$ (4,700)	$(21,383)	$(10,398)
Weighted average shares – basic and diluted	20,315	19,704	14,286
Net loss per share – basic and diluted:			
Loss before extraordinary item	$ (0.23)	$ (1.06)	$ (0.73)
Extraordinary item, net of income taxes	–	(0.03)	-
Net loss per common share	$ (0.23)	$ (1.09)	$ (0.73)

NOTE 8 - EXTRAORDINARY ITEM

For the year ended December 31, 2001, we recognized an extraordinary loss of $0.6 million, net of income taxes, related to the early extinguishment of our non-recourse borrowings. This loss will be reclassified to interest expense and income tax benefit upon the adoption of SFAS 145.

NOTE 9 – INCOME TAXES

The benefit (provision) for income taxes before extraordinary item consisted of the following (in thousands):

	Years Ended December 31,		
	2002	2001	2000
Current:			
State	$ –	$ –	$ –
Federal	229	–	–
	229	–	–
Deferred:			
State	–	–	–
Federal	2,352	11,186	5,594
	2,352	11,186	5,594
Benefit for income taxes before extraordinary item	$2,581	$11,186	$5,594

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

	Years Ended December 31,		
	2002	2001	2000
Statutory federal income tax rate	(35.00)%	(35.00)%	(35.00)%
Nondeductible and other	(0.39)	0.01	0.02
	(35.39)%	(34.99)%	(34.98)%

Significant components of our deferred tax assets (liabilities) as of December 31, 2002 and 2001 are as follows (in thousands):

	December 31,	
	2002	2001
Deferred tax assets:		
Net operating loss carryforwards	$19,550	$ 3,809
Minimum tax credit carryforwards	–	229
Fixed asset basis differences	(5,427)	11,367
State taxes	17	17
Unrealized book (gains) losses	2,415	(443)
Stock based compensation expense	1,107	1,177
Litigation	1,101	1,050
Foreign equity in subsidiary	1,989	1,152
Deferred taxes related to SFAS 133	1,628	–
Other	828	870
Net deferred tax assets	$23,208	$19,228

At December 31, 2002, 2001 and 2000, we had net operating loss carryforwards for federal income tax purposes of approximately $55.9 million, $10.7 million, and $11.0 million respectively, which are available to offset future federal taxable income through 2021.

At December 31, 2002 we have determined that it is more likely than not the deferred tax assets will be realized based on current projections of future taxable income due to higher commodity prices at year-end.

A tax benefit related to the exercise of employee stock options of approximately $0.1 million was allocated directly to additional paid-in capital in 2001.

Additionally, a tax benefit of $0.3 million was recognized related to the extraordinary loss for the year ended December 31, 2001.

NOTE 10 – COMPREHENSIVE LOSS

Comprehensive loss consists of net loss, as reflected on the consolidated statement of operations, and other gains and losses affecting shareholders' equity that are excluded from net loss. We recorded other comprehensive income for the first time in 2001.

The components of comprehensive loss are as follows (in thousands):

	Year Ended December 31,	
	2002	2001
Net loss	$(4,700)	$(21,383)
Other comprehensive income (loss), net of tax:		
Cumulative effect of change in accounting principle – January 1, 2001	–	(34,252)
Reclassification adjustment for settled contracts	627	34,252
Change in fair value of outstanding hedging positions	(3,651)	–
Foreign currency translation adjustment	670	19
Other comprehensive income (loss)	(2,354)	19
Comprehensive loss	$(7,054)	$(21,364)

NOTE 11 – COMMITMENTS AND CONTINGENCIES

Operating Leases / We have commitments under an operating lease agreement for office space. Total rent expense for the years ended December 31, 2002, 2001 and 2000 was approximately $0.5 million, $0.3 million and $0.2 million respectively. At December 31, 2002, the future minimum rental payments due under the lease are as follows (in thousands amounts):

2003	$ 539
2004	539
2005	371
2006	289
2007	214
Later Years	997
Total	$ 2,949

Contingencies / In 2001 we purchased three properties in the U.K. Sector – North Sea for approximately $3.1 million. In accordance with the purchase agreement, we also committed to pay future consideration contingent upon the successful development and operation of the properties. The contingent consideration for each property includes amounts to be paid upon achieving first commercial production and upon achieving designated cumulative production levels. Active development is in progress on our Helvellyn property and future development is planned on the other two properties. First commercial production from the Helvellyn property may occur sometime in the second quarter of 2003. Although a significant portion of the work required has been completed, there remains significant additional work to be performed before this property can produce commercially. That work includes completion, hook-up, and testing of the pipeline and production facilities and final negotiation of certain terms in our transportation and processing agreements. Accordingly, there can be no assurance of eventual production from this development until the aforementioned activities are completed successfully. At such time, the required amount will be accrued for payment to the seller and capitalized as acquisition costs.

Litigation / On August 28, 2001 ATP entered into a written agreement to acquire a property in the Gulf of Mexico during September 2001. On October 9, 2001 the agreement was amended to ultimately extend the closing date until October 31, 2001 in exchange for payments made by ATP totaling $3.0 million. This amendment also contained an arrangement whereby if ATP did not close on the property, and if sellers sold the property to a third party with a sale that met specific contract requirements, ATP would be required to execute a six month note for payment of the differential. Since ATP did not obtain the financing for the acquisition by October 31, 2001, the transaction did not close by that date; however, the parties' intensive work toward closing continued beyond that date without interruption.

While working on the closing for the property with ATP, the sellers sold the property to a third party without informing ATP until after the closing had taken place. ATP filed an action in the District Court of Harris County, Texas against the sellers, generally alleging improper sale of the offshore property to a third party and breach of contract, and seeking unspecified damages from the sellers. The case is encaptioned *ATP Oil & Gas Corporation vs. Legacy Resources Co., L.P. et al,* No. 2001-63224 in the 269th Judicial District Court of Harris County, Texas. At the same time sellers notified ATP of their sale to a third party, the sellers had a demand made upon ATP for execution of a six month note for the amount of an alleged differential of approximately $12.3 million plus interest at 16%. Substantiation of the amount and validity of the demand could not be ascertained based on the content of the demand received. ATP contested the entire demand. The judge has abated the litigation, until arbitration pursuant to the underlying agreements between the sellers and ATP is completed. A tentative date of May 19, 2003 has been scheduled for the arbitration with an alternative date in September 2003. Due to the inherent uncertainties involving contested facts and legal issues a prediction as to the likely outcome cannot be made with any degree of certainty, and we have not accrued any amount related to this matter. While we are seeking recovery of the amounts previously paid and discussed above, the $3.0 million has been charged to earnings along with other costs related to this matter. ATP intends to vigorously defend against the sellers' claims and forcefully pursue its own claims in this matter.

In August 2001, Burlington Resources Inc. filed suit against ATP alleging formation of a contract with ATP and our breach of the alleged contract. The complaint seeks compensatory damages of approximately $1.1 million. We believe that this claim is without merit, and we intend to defend it vigorously.

We are also, in the ordinary course of business, a claimant and/or defendant in various legal proceedings. Management does not believe that the outcome of these legal proceedings, individually, and in the aggregate will have a materially adverse effect on our financial condition, results of operations or cash flows.

NOTE 12 – DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT ACTIVITIES

On January 1, 2001, we adopted SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities"* ("SFAS 133"), as amended, and recorded a cumulative transition loss of $34.3 million, net of tax, to accumulated other comprehensive income (loss) to account for the effect of the change in accounting principle. The standard requires that all derivatives be recorded on the balance sheet at fair value and establishes criteria for documentation and measurement of hedging activities.

We occasionally use derivative instruments with respect to a portion of our oil and gas production to manage our exposure to price volatility. These instruments may take the form of futures contracts, swaps or options.

Prior to July 1, 2002, we had not attempted to qualify our derivatives for the hedge accounting provisions under SFAS 133. Accordingly, we accounted for the changes in market value of these derivatives through current earnings. Gains and losses on all derivative instruments prior to July 1, 2002 were included in other income (expense) on the consolidated financial statements.

Loss on derivative instruments is comprised of the following components (in thousands):

	Years Ended December 31,		
	2002	2001	2000
Loss on settled contracts	$ (153)	$(19,348)	$ –
Loss on speculative positions [1]	–	–	(4,662)
Loss on open speculative positions [1]	–	–	(7,249)
Gain (loss) on open derivative positions	(8,166)	1,265	–
	$(8,319)	$(18,083)	$(11,911)

[1] *In 2000, we found ourselves in a speculative position 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. This position was accounted for using the mark-to-market method.*

As of July 1, 2002, we performed the requisite steps to qualify our existing derivative instruments for hedge accounting treatment under the provisions of SFAS 133. Derivative instruments designated as cash flow hedges are reflected at fair value on our consolidated balance sheets. Changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income (loss) until the hedged item is settled and is recognized in earnings. Any ineffective portion of the derivative instrument's change in fair value is recognized in revenues in the current period. Hedge effectiveness is measured at least quarterly.

Oil and gas revenues are comprised of the following components for the periods indicated (in thousands):

	Years Ended December 31,		
	2002	2001	2000
Oil and gas production	$89,415	$105,757	$104,163
Derivative settlements during the period	(3,225)	–	(28,223)
	86,190	105,757	75,940
Amounts previously recognized in earnings prior to July 1, 2002 qualification for hedge accounting [1]	3,225	–	–
Change in fair value of derivative hedging positions [2]	(964)	–	–
Ineffective portion of derivative hedging instruments	(300)	–	–
	$88,151	$105,757	$ 75,940

[1] *Represents the mark to market valuation of open positions at June 30, 2002 which were previously recognized in other income (expense).*

[2] *Represents the change in fair value of settled positions between the beginning and end of the period.*

At December 31, 2002, a $4.6 million loss ($3.0 million after tax) was recorded to accumulated other comprehensive loss for the effective portion of the change in fair market value during the last six months of 2002. All of this deferred loss will be reversed during the next twelve months as the forecasted transactions actually occur, assuming no further changes in fair market value. All forecasted transactions currently being hedged are expected to occur by December 2003. As of December 31, 2002, the fair value of the outstanding derivative instruments was a current liability of $9.6 million. This amount represents the difference between contract prices and future market prices on contracted volumes of the commodities as of December 31, 2002.

As of December 31, 2002, we had derivative contracts in place for the following natural gas and oil volumes:

Period	Volumes	Average Fixed Price
Natural gas (MMBtu):		
2003	6,080,000	$ 3.02
Oil (Bbl):		
2003	182,500	24.10

In addition to these derivative instruments, we also manage our exposure to oil and gas price risks by periodically entering into fixed-price delivery contracts. As of December 31, 2002, we had fixed-price contracts in place for the following natural gas and oil volumes:

Period	Volumes	Average Fixed Price (1)
Natural gas (MMBtu):		
2003	5,173,000	$ 3.83
Oil (Bbl):		
2003	227,500	26.41

The following table summarizes all derivative instruments and fixed-price contracts as of December 31, 2002:

Period	Volumes	Average Fixed Price (1)
Natural gas (MMBtu):		
2003	11,253,000	$ 3.39
Oil (Bbl):		
2003	410,000	25.38

(1) *Includes the effect of basis differentials.*

Thus far, in 2003 we have entered into the following fixed-price contracts:

Period	Volumes	Average Fixed Price [1]
Natural gas (MMBtu):		
2004	3,403,000	$ 4.32
Oil (Bbl):		
2003	44,500	31.61

[1] *Includes the effect of basis differentials.*

Additionally in 2003, we entered into a costless collar arrangement for 300,000 MMBtu of our natural gas production for the months of January through March 2004 with a floor of $4.40 per MMBtu and a ceiling of $5.80 MMBtu. Collar arrangements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. They provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price is below the floor.

NOTE 13 – ATP ENERGY GAS PURCHASE TRANSACTION

ATP Energy entered an agreement in December 1998 with American Citigas Company ("American Citigas") 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 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 ATP. The note receivable bears interest at 6% and has monthly payments of approximately $0.4 million until January 2009. The balance of the note receivable at December 31, 2002 and 2001 was $22.9 million and $25.9 million, respectively. At December 31, 2002 and 2001, the present value of the remaining premium payments to be made by ATP Energy, using a discount rate of 6%, was $22.7 million and $25.8 million, respectively. 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 FASB Interpretation No. 39, *"Offsetting of Amounts Related to Certain Contracts"*. 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, 2002 the remaining premium to be paid was $27.1 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 and has been renewed on a month-to-month basis since then.

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. 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, 2002 and 2001, the deferred revenue amount was $1.1 million and $1.3 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 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.

Our officers were paid $152,125 for the year ended December 31, 2000 for negotiating and monitoring ATP Energy's gas supply contract. We have recognized these amounts in general and administrative expense in the respective periods. No amounts were paid in 2002 and 2001 and we do not intend to pay any further amounts.

NOTE 14 – RELATED PARTY TRANSACTIONS

We have granted to certain of our officers 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, we recognized $0.3 million in general and administrative expense for the year ended December 31, 2000. No amounts were paid in 2002 and 2001 and we do not intend to pay any further amounts.

NOTE 15 – SEGMENT INFORMATION

We follow SFAS No. 131, "Disclosures About Segments of an Enterprise and Related Information," which requires that companies disclose segment data based on how management makes decisions about allocating resources to segments and measuring their performance. We manage our business and identify our segments based on geographic areas. We have two reportable segments: our operations in the Gulf of Mexico and our operations in the North Sea. Both of these segments involve oil and gas producing activities. Following is certain financial information regarding our segments for 2002, 2001 and 2000 (in thousands).

	Gulf of Mexico	North Sea	Total
2002			
Revenues	$ 94,423	$ –	$ 94,423
Depreciation, depletion and amortization	43,292	98	43,390
Impairment of oil and gas properties	6,844	–	6,844
Operating income (loss)	12,728	(2,426)	10,302
Total assets	144,069	37,986	182,055
Additions to oil and gas properties	18,520	16,353	34,873
2001			
Revenues	$113,174	$ –	$113,174
Depreciation, depletion and amortization	53,376	52	53,428
Impairment of oil and gas properties	24,891	–	24,891
Operating loss	(1,825)	(2,904)	(4,729)
Total assets	172,300	5,264	177,564
Additions to oil and gas properties	106,433	3,831	110,264
2000			
Revenues	$ 83,988	$ –	$ 83,988
Depreciation, depletion and amortization	40,563	6	40,569
Impairment of oil and gas properties	10,838	–	10,838
Operating income (loss)	7,813	(438)	7,375
Total assets	161,400	593	161,993
Additions to oil and gas properties	76,086	388	76,474

NOTE 16 – SUMMARIZED QUARTERLY FINANCIAL DATA (UNAUDITED)

(In Thousands, Except Per Share Amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2002				
Revenues	$19,790	$29,311	$24,668	$ 20,654
Costs and expenses	19,489	20,950	19,446	24,236 (1)
Income (loss) from operations	301	8,361	5,222	(3,582)
Net income (loss)	(6,363)	3,171	1,665	(3,173)
Net income (loss) per common share:				
Basic and diluted (3)	$ (0.31)	$ 0.16	$ 0.08	$ (0.16)
2001				
Revenues	$41,443	$31,035	$20,883	$ 19,813
Costs and expenses	28,701 (2)	29,694 (2)	24,659 (2)	34,849 (2)
Income (loss) from operations	12,742	1,341	(3,776)	(15,036)
Income (loss) before extraordinary item	(6,873)	3,813	(6,499)	(11,222)
Net income (loss)	(6,873)	3,211	(6,499)	(11,222)
Income (loss) per common share before extraordinary item, basic and diluted	$ (0.38)	$ 0.19	$ (0.32)	$ (0.55)
Net income (loss) per common share:				
Basic and diluted (3)	$ (0.38)	$ 0.16	$ (0.32)	$ (0.55)

(1) *Includes impairment charges of $6.8 million during the fourth quarter for two properties.*

(2) *Includes impairment charges of $8.5 million, $5.7 million, $3.7 million and $7.0 million during the first, second, third and fourth quarters, respectively, for eight properties.*

(3) *The sum of the per share amounts per quarter does not equal the year due to the changes in the average number of common shares outstanding*

OIL AND GAS RESERVES AND RELATED FINANCIAL DATA (UNAUDITED)

Costs Incurred / The following table summarizes costs incurred in natural gas and oil property acquisition, exploration and development activities are summarized below (in thousands):

	Gulf of Mexico	North Sea	Total
2002			
Property acquisition costs:			
Unproved	$ 959	$ –	$ 959
Proved	–	–	–
Development costs	17,561	16,353	33,914
	$ 18,520	$16,353	$ 34,873
2001			
Property acquisition costs:			
Proved	$ 28,344	$ 3,112	$ 31,456
Development costs	77,783	719	78,502
	$106,127	$ 3,831	$109,958
2000			
Property acquisition costs:			
Proved	$ 7,354	$ –	$ 7,354
Development costs	68,982	–	68,982
	$ 76,516	$ –	$ 76,516

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.

Reserves quantities as well as certain information regarding future production and discounted cash flows were prepared by independent petroleum engineers Ryder Scott Company, L.P. for all years presented and Schlumberger Holditch-Reservoir Technologies Consulting Services for one property for 2000. Our U.K. reserves at December 31, 2002 and 2001 were prepared by independent petroleum consultants Troy Ikoda Limited.

The following table sets forth our net proved oil and gas reserves at December 31, 1999, 2000, 2001 and 2002 and the changes in net proved oil and gas reserves for the years ended December 31, 2000, 2001 and 2002:

	Natural Gas (MMcf)			Oil, Condensate and Natural Gas Liquids (MBbls)		
	Gulf of Mexico	North Sea	Total	Gulf of Mexico	North Sea	Total
Proved Reserves at December 31, 1999	93,997	–	93,997	1,689	–	1,689
Revisions of previous estimates	(19,423)	–	(19,423)	(46)	–	(46)
Extensions and discoveries	7,239	–	7,239	77	–	77
Purchase of properties	42,318	–	42,318	2,602	–	2,602
Disposition of properties	(151)	–	(151)	–	–	–
Production	(22,410)	–	(22,410)	(345)	–	(345)
Proved Reserves at December 31, 2000	101,570	–	101,570	3,977	–	3,977
Revisions of previous estimates	(6,793)	–	(6,793)	134	–	134
Purchase of properties	40,060	80,629	120,689	3,432	–	3,432
Production	(20,957)	–	(20,957)	(790)	–	(790)
Proved Reserves at December 31, 2001	113,880	80,629	194,509	6,753	–	6,753
Revisions of previous estimates	1,594	9,314	10,908	441	–	441
Purchase of properties	4,696	20,272	24,968	–	–	–
Disposition of properties	–	(17,115)	(17,115)	–	–	–
Production	(17,732)	–	(17,732)	(1,454)	–	(1,454)
Proved Reserves at December 31, 2002	102,438	93,100	195,538	5,740	–	5,740

	Natural Gas (MMcf)			Oil, Condensate and Natural Gas Liquids (MBbls)		
	Gulf of Mexico	North Sea	Total	Gulf of Mexico	North Sea	Total
Proved Developed Reserves at						
December 31, 1999	67,314	–	67,314	710	–	710
December 31, 2000	42,502	–	42,502	851	–	851
December 31, 2001	56,704	–	56,704	3,115	–	3,115
December 31, 2002	34,068	–	34,068	2,318	–	2,318

Standardized Measure / The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves as of year-end is shown below (in thousands):

	Gulf of Mexico	North Sea	Total
2002			
Future cash inflows	$ 649,927	$ 205,629	$ 855,556
Future operating expenses	(69,215)	(78,131)	(147,346)
Future development costs	(128,803)	(109,510)	(238,313)
Future net cash flows	451,909	17,988	469,897
Future income taxes	(129,435)	(929)	(130,364)
Future net cash flows, after income taxes	322,474	17,059	339,533
10% annual discount per annum	(74,770)	(5,870)	(80,640)
Standardized measure of discounted future net cash flows	$ 247,704	$ 11,189	$ 258,893
2001			
Future cash inflows	$ 423,273	$ 302,894	$ 726,167
Future operating expenses	(59,722)	(100,330)	(160,052)
Future development costs	(100,919)	(111,044)	(211,963)
Future net cash flows	262,632	91,520	354,152
Future income taxes	(35,469)	(26,188)	(61,657)
Future net cash flows, after income taxes	227,163	65,332	292,495
10% annual discount per annum	(54,247)	(25,584)	(79,831)
Standardized measure of discounted future net cash flows	$ 172,916	$ 39,748	$ 212,664
2000			
Future cash inflows	$1,139,404	$ –	$1,139,404
Future operating expenses	(70,719)	–	(70,719)
Future development costs	(137,453)	–	(137,453)
Future net cash flows	931,232	–	931,232
Future income taxes	(285,587)	–	(285,587)
Future net cash flows, after income taxes	645,645	–	645,645
10% annual discount per annum	(121,164)	–	(121,164)
Standardized measure of discounted future net cash flows	$ 524,481	$ –	$ 524,481

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 PV-10 calculation were public market prices on December 31 adjusted by differentials to those market prices. These price adjustments 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 West Texas Intermediate prices, before adjustment for quality and transportation, utilized in the Pretax PV-10 value at December 31, 2002 were $4.74 per MMBtu of natural gas and $31.23 per barrel of oil. The National Balancing Point (the U.K. natural gas benchmark), before adjustment for quality and transportation, utilized in the PV-10 value at December 31, 2002 was $2.20 per MMBtu of natural gas. Estimates of future development and production costs are based on year-end costs and assume continuation of existing economic conditions and year-end prices. We will incur significant capital in the development of our Gulf of Mexico and North Sea oil and gas properties. We believe with reasonable certainty that we will be able to obtain such capital in the normal course of business. 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.

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):

	Gulf of Mexico	North Sea	Total
2002			
Beginning of year	$ 172,916	$ 39,748	$ 212,664
Sales of oil and gas, net of production costs	(72,658)	–	(72,658)
Net changes in income taxes	(68,837)	24,007	(44,830)
Net changes in price and production costs	192,111	(30,166)	161,945
Revisions of quantity estimates	13,666	10,893	24,559
Accretion of discount	20,001	6,427	26,428
Development costs incurred	13,163	14,413	27,576
Changes in estimated future development costs	(23,508)	(10,670)	(34,178)
Purchases of minerals-in-place	8,252	662	8,914
Sales of minerals-in-place	–	(13,664)	(13,664)
Changes in production rates, timing and other	(7,402)	(30,461)	(37,863)
	74,788	(28,559)	46,229
End of year	$ 247,704	$ 11,189	$ 258,893
2001			
Beginning of year	$ 524,481	$ –	$ 524,481
Sales of oil and gas, net of production costs	(90,951)	–	(90,951)
Net changes in income taxes	193,247	(24,517)	168,730
Net changes in price and production costs	(593,914)	–	(593,914)
Revisions of quantity estimates	(11,220)	–	(11,220)
Accretion of discount	74,483	–	74,483
Development costs incurred	57,119	–	57,119
Changes in estimated future development costs	22,413	–	22,413
Purchases of minerals-in-place	64,322	64,265	128,587
Changes in production rates, timing and other	(67,064)	–	(67,064)
	(351,565)	39,748	(311,817)
End of year	$ 172,916	$ 39,748	$ 212,664
2000			
Beginning of year	$ 128,706	$ –	$ 128,706
Sales of oil and gas, net of production costs	(64,381)	–	(64,381)
Net changes in income taxes	(193,613)	–	(193,613)
Net changes in price and production costs	416,738	–	416,738
Revisions of quantity estimates	(147,777)	–	(147,777)
Accretion of discount	15,632	–	15,632
Development costs incurred	18,134	–	18,134
Changes in estimated future development costs	(14,709)	–	(14,709)
Purchases of minerals-in-place	300,706	–	300,706
Sales of minerals-in-place	(525)	–	(525)
Extensions and discoveries	51,795	–	51,795
Changes in production rates, timing and other	13,775	–	13,775
	395,775	–	395,775
End of year	$ 524,481	$ –	$ 524,481

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.

Capitalized Costs Related to Oil and Gas Producing Activities / The following table summarizes capitalized costs related to our oil and gas operations (in thousands):

	Gulf of Mexico	North Sea	Total
2002			
Oil and gas properties:			
Unproved	$ 959	$ –	$ 959
Proved	333,082	21,047	354,129
Accumulated depletion, impairment and amortization	(236,052)	–	(236,052)
	$ 97,989	$21,047	$ 119,036
2001			
Oil and gas properties:			
Proved	$ 315,287	$ 4,219	$ 319,506
Accumulated depletion, impairment and amortization	(186,473)	–	(186,473)
	$ 128,814	$ 4,219	$ 133,033

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

This excerpt from our annual report on Form 10-K includes assumptions, expectations, projections, intentions or beliefs about future events. These statements are intended as "forward-looking statements" under the Private Securities Litigation Reform Act of 1995. We caution that assumptions, expectations, projections, intentions and beliefs about future events may and often do vary from actual results and the 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;
- 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
- estimates of quantities of our proved reserves and the present value thereof, 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;
- our ability to identify and acquire additional properties necessary to implement our business strategy and our ability to finance such 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;
- the political and economic climate in the foreign or domestic jurisdictions in which we conduct oil and gas operations, including risk of war or potential adverse results of military or terrorist actions in those areas; and
- other United States 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.

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 20,338,753 shares of common stock and no shares of preferred stock outstanding as of March 21, 2003. There were 61 holders of record of our common stock as of March 21, 2003. 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 following tables sets forth the range of high and low closing sales prices for the common stock as reported on the Nasdaq National Market for the periods indicated below:

	High	Low
2002:		
4th Quarter	$ 4.49	$ 2.78
3rd Quarter	3.40	2.51
2nd Quarter	4.77	2.50
1st Quarter	5.00	1.47
2001:		
4th Quarter	$ 7.15	$ 2.00
3rd Quarter	12.00	6.61
2nd Quarter	12.96	8.71
1st Quarter	14.56	9.88

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.

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Chairman and President

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Senior Vice President

Leland E. Tate
Senior Vice President, Operations

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

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

Carol E. Overbey
Vice President, Corporate Secretary

Adrian Turner
Managing Director, ATP Oil & Gas (UK) Limited

Hans Ryckborst
Managing Director, ATP Oil & Gas (Netherlands) B.V.

G. Ross Frazer
Vice President, Engineering

Robert M. Shivers
Vice President, Special Projects

Mickey W. Shaw
Vice President, Production Operations

George R. Morris
Vice President, Acquisitions

Keith R. Godwin
Vice President, Controller

Isabel M. Plume
Assistant Corporate Secretary

Directors

T. Paul Bulmahn
Chairman of the Board and President
ATP Oil & Gas Corporation

Arthur H. Dilly
Chairman and CEO
Austin Geriatrics Center, Inc.
Former Executive Secretary
Board of Regents of the University of Texas System

Chris A. Brisack
Partner
Norquest & Brisack, LLP

Robert C. Thomas
Chairman
The Sarkeys Energy Center of the University of Oklahoma
Former Chairman and CEO of Tenneco Gas

Walter Wendlandt
Former Director
Railroad Commission of Texas

Gerard J. Swonke
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SHAREHOLDER INFORMATION

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NASDAQ

Ticker
ATPG

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Form 10K
A copy of the company's 2002 Form 10K, as filed with the Securities and Exchange Commission, is available on our website www.atpog.com under Investor Info/Annual Quarterly Reports and SEC Reports, or may be obtained at no charge by written request to Isabel Plume, Investor Relations at the company's address listed above.

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