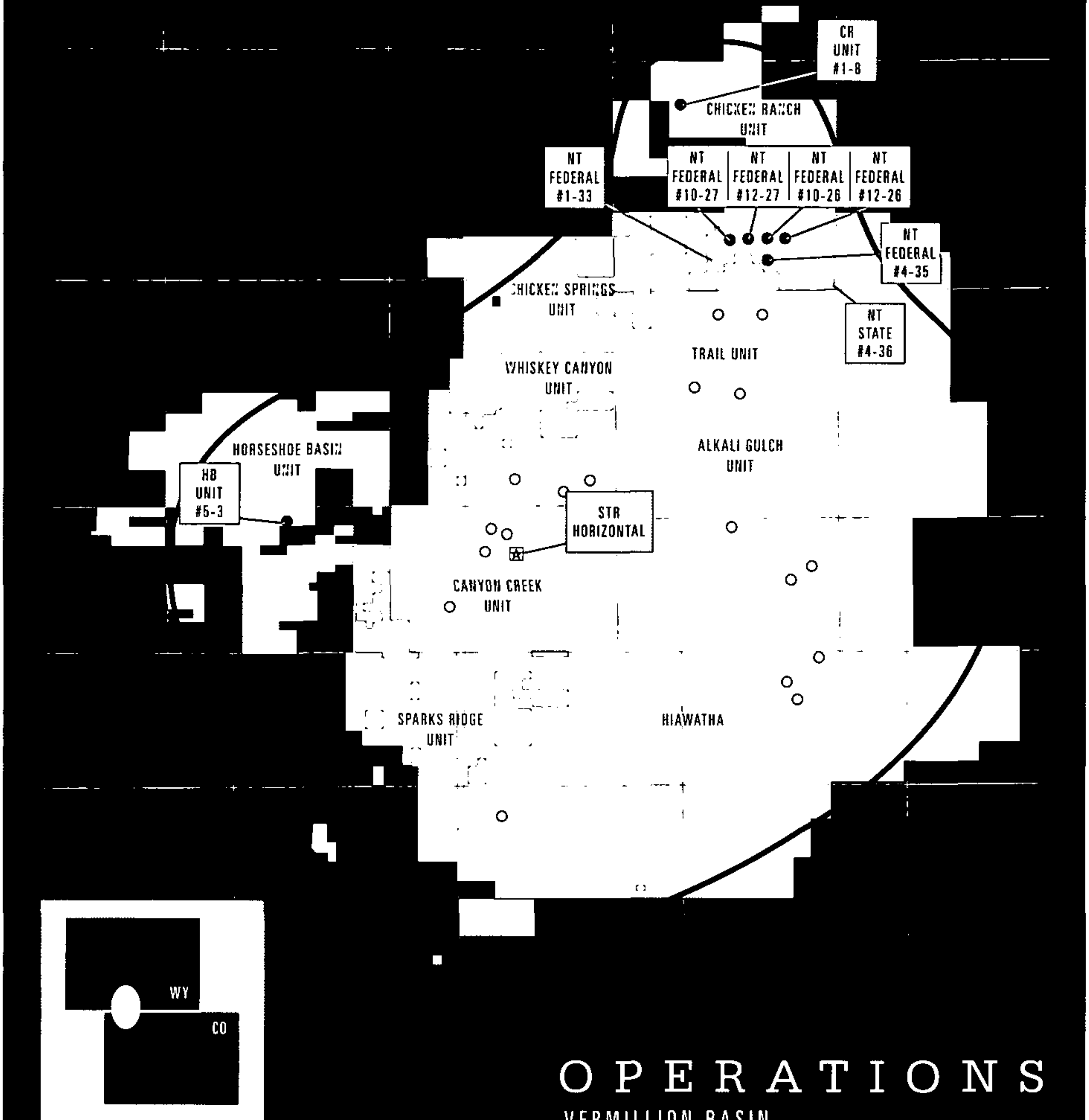
KODIAK

OIL & GAS CORP.

CAPTURING OPPORTUNITY

2006 ANNUAL REPORT



OPERATIONS

VERMILLION BASIN

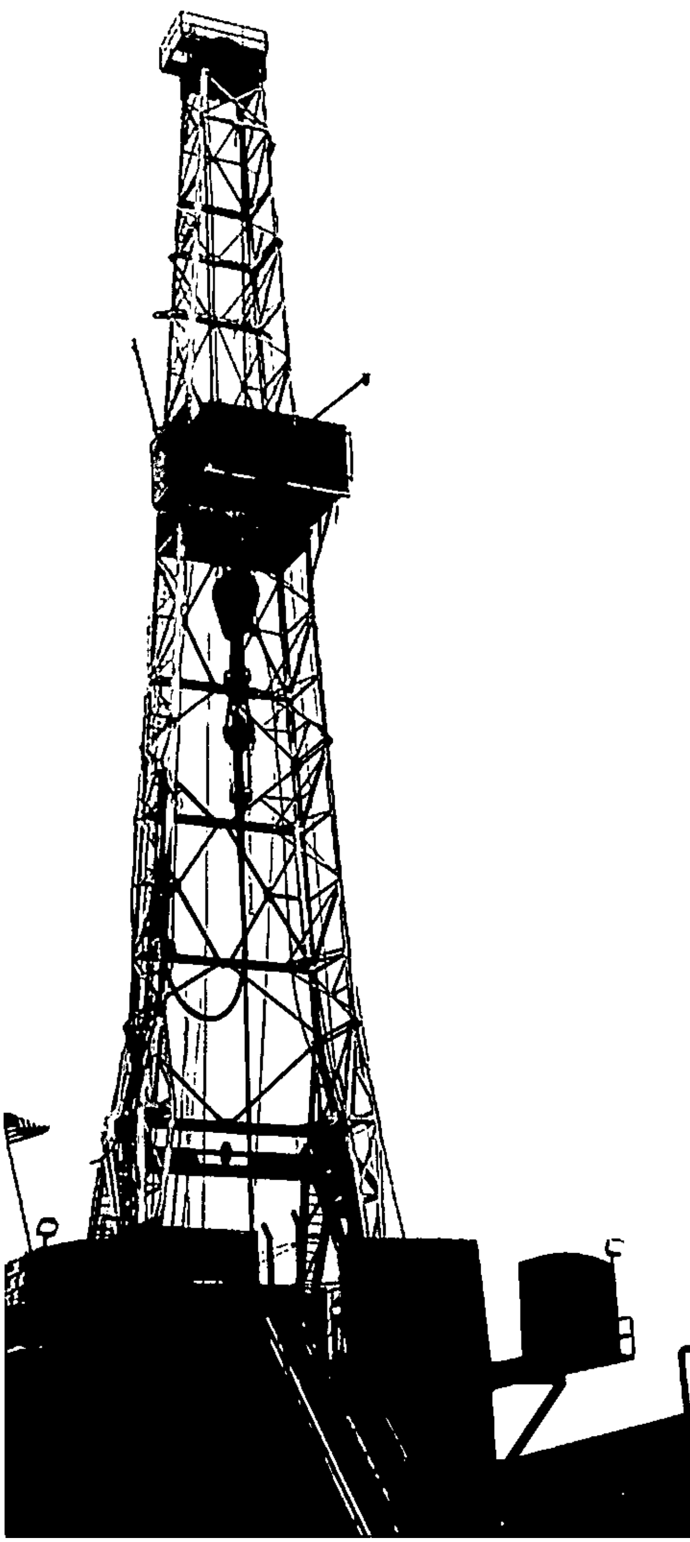
- ○ BAXTER FRONTIER PRODUCER
- ● KODIAK PROPOSED LOCATION
- ○ KODIAK LEASEHOLD
- — DEEP GAS PLAY AREA

KODIAK

OIL & GAS CORP.

CAPTURING OPPORTUNITY

We are pleased to recap what was the most pivotal year in Kodiak's six-year history. We were afforded many opportunities during 2006, and they all contributed to help position Kodiak as a leading independent oil and gas company operating in the Rocky Mountains. Timely core-area acquisitions, access to capital, a senior listing on a U.S. exchange and the hiring of key technical personnel all contributed to our transformation from early-stage E&P to a company taken seriously by investors and industry alike. We now have the people, the projects, the capital, and most important, the momentum to make 2007 an even better year for Kodiak.



Consider the following 2006 events:

In March, we completed a US$37 million private placement of common shares allowing us to begin proving our Vermillion Basin geologic model by fully funding our 2006 CAPEX

In June, we began trading on the American Stock Exchange, providing greater liquidity and access to U.S. institutions

In July, our extensive geological & geophysical program culminated in the permitting of several locations prospective for the Baxter Shale in our Vermillion Basin operating area

Throughout the year, we enjoyed success in the Williston Basin Bakken Shale play, providing the Company with meaningful cash flow as we prepared the Vermillion for 2007 drilling

In October, we spud our initial Baxter Shale test followed by our second well in December

Also in October, we bolstered our technical team by hiring an engineer, who had spent the bulk of his career perfecting completions in over-pressured Rockies gas formations

In December, we raised an additional US$47 million through a successful public offering which, along with operating cash flow, will fund our 2007 drilling program

By year-end, we were over 70% held by institutions and were covered by seven sell-side analysts

Our formative years, while decidedly fast and furious, are largely behind us. Through hard work by each of Kodiak's 12 employees, we have shaped Kodiak into a company that is ready to capitalize on the opportunities we generated in 2005, and, even more so, in 2006. While 2006 was a success by any measure, we now must convert the capital invested in the Company into strong operational and financial performance. We now enter a phase whereby investors will begin measuring our success by growth in reserves, production and other metrics by which we are judged against our peers.

In order to deliver results, we like where we stand with regard to existing assets in both people and properties. At December 31, 2006, we owned or controlled 123,000 gross (80,000 net) acres. Our leasehold in the Vermillion Basin, 42,000 gross acres (26,000 net) acres, is an important catalyst for generating growth and value for our shareholders. Our leasehold here includes several hundred gross unrisked locations, with a strong 65% average working interest, and is prospective for over-pressured natural gas bearing formations. The inventory presents Kodiak and its shareholders high-potential, drill-bit growth going forward.

At a time where acquiring high-quality leasehold in most North American plays is prohibitively expensive to small companies, the location inventory is even more valuable. To begin leveraging the resource potential here, we have set an initial capital expenditure budget of $36 million to target 7.5 net Vermillion deep wells. Our first two wells drilled here in 2006, the North Trail State #4-36 and the NT Federal #1-33, provided our technical team with invaluable experience to further refine drilling and completion operations in future wells. We recognize the value of the Vermillion as an important asset for Kodiak, and continue to hone our techniques to deliver optimal performance to enhance overall well economics in the play.

Our drill-bit growth strategy also extends to the Williston Basin, where we exited December 2006 operating 700 barrels of light sweet crude per day. We maintain an inventory of locations here, some of which we will drill as part of our active drilling program. The 2007 CAPEX for the Williston is $18.7 million for 4.8 net wells which should, as it has in the past, provide a stable source of cash flow in 2007.

Financials

We exited 2006 with a rate of 400 BOEPD net, 85% of which was Williston oil. Oil and gas sales for the year totaled $4.2 million with total revenues of nearly $5 million, which compares to $0.366 million and $0.453 million respectively for 2005. At December 31, 2006, Kodiak had estimated proved reserves of 5.6 Bcfe, 57% of which was crude oil and 97% was classified as proved developed. The SEC PV-10 value at year-end 2006 was $19.7 million. We closed the year with $51.2 million of working capital, which should allow us to execute our planned drilling program and achieve additional reserve growth in 2007.

On behalf of the Board of Directors, we would like to thank Kodiak's employees and our growing investor base for their on-going efforts and dedication to the Company's growth. We are confident that we have the technical team in place that will advance our growth initiative in a meaningful way in 2007. Together, we will capture the opportunities that we generated in the formative years, while creating additional opportunities for Kodiak's future.

Lynn A. Peterson
President, Chief Executive Officer and Director

James E. Catlin
Chief Operating Officer and Chairman of the Board

OPERATIONS

VERMILLION BASIN

Profile

- Targeting over-pressured, tight-gas formations including the Baxter Shale, the Frontier and Dakota Sandstones, and normal-pressured Almond, Ericson and Rock Springs sands
- Core Vermillion area comprises 41,845 gross (26,293 net) acres at 12/31/06
- Potential for over 650 net Baxter/Frontier/Dakota locations based on 40-acre spacing
- Federal Units provide for orderly plan of development
- Multi-company Environmental Impact Study (EIS) ongoing
- 65% average working interest, 75% operated

2006 Activity

- Invested $20.5 million
- Spudded two 100% WI Baxter Shale tests
- Drilled and completed 3 gross (1.5 net) shallow gas wells
- Continued adding to acreage position
- Developed and permitted new prospects for additional drilling in 2007 and beyond

2007 Plans

- $36.2 million drilling CAPEX targets 9 gross (7.5 net) Baxter Shale wells
- $5 million allocated for acquiring modern, high-fold, 3-D seismic
- Infrastructure improvements and compression
- Seek additional acquisition opportunities and undeveloped acreage

OPERATING AREAS

Kodiak Oil & Gas concentrates its operations in two core Rocky Mountain basins— the Vermillion Basin of the Greater Green River Basin in Wyoming and the Williston Basin of North Dakota and Montana. The basins offer disparate commodity product mix, with the Vermillion prospective for tight-gas sands and shales and the Williston typically an oil-prone basin. Together, our operations include 123,000 gross acres (80,000 net); 11 operated wells and proved reserves net to Kodiak of 5.6 billion cubic feet of natural gas equivalents. On average, Kodiak controls a 65% working interest over our acreage position.

Maintaining a high working interest and operating our properties are equally important to Kodiak. As a lean operation, we are especially keen on controlling our destiny with regard to the timing of the development of our oil and gas fields. All of Kodiak's operations are run from our Denver headquarters where we employ geological and geophysical staff, engineers, and landmen with broad-based Rockies oil and tight-gas experience.

Vermillion Basin of the Greater Green River Basin

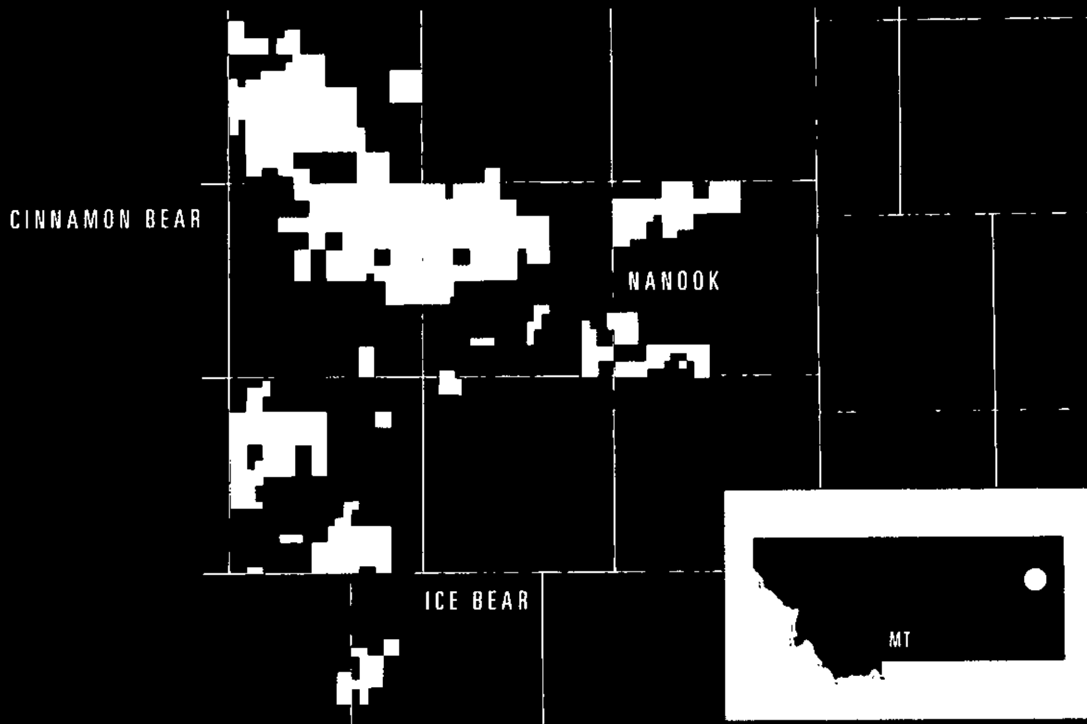
Sweetwater, Wyoming and Moffat County, Colorado

Kodiak gained entry into the area in 2001 with acreage prospective for coalbed methane (CBM) and shallow gas sands. Early exploration efforts focused on the shallower Mesaverde sands and coals. Since that time, Kodiak has added to its lands though a series of swaps and transactions resulting in today's 41,845 gross and 26,293 net acres in the Vermillion Basin.

By monitoring industry activity in the basin, Kodiak further identified Baxter Shale potential underlying its leasehold. The Baxter/Frontier/ Dakota play is now the focus of Kodiak's exploration and development plans in the Vermillion Basin. The Company is currently participating in an ongoing environmental impact study that should help determine the ultimate pace at which the acreage can best be developed. The study, performed by the Bureau of Land Management, is expected to be completed in 2008. Elsewhere in the Green River Basin, Kodiak has acquired over 10,000 gross acres covering several prospect areas targeting the Frontier, Muddy and Lewis sands and the Mancos Shale.

Williston Basin of North Dakota and Montana

Kodiak's land department worked diligently to assemble fee leasehold in the oil-prone Williston Basin over the past two years. Our exploration focuses on the Mission Canyon, Bakken and Red River formations which can be found across our 59,239 gross (38,212 net) acres. We have run one rig continuously for nearly two years and anticipate similar activity in 2007. Recently, Kodiak acquired an additional 8,000 acres in North Dakota that we believe is prospective for Bakken Shale oil.



OPERATIONS

WILLISTON BASIN

Profile

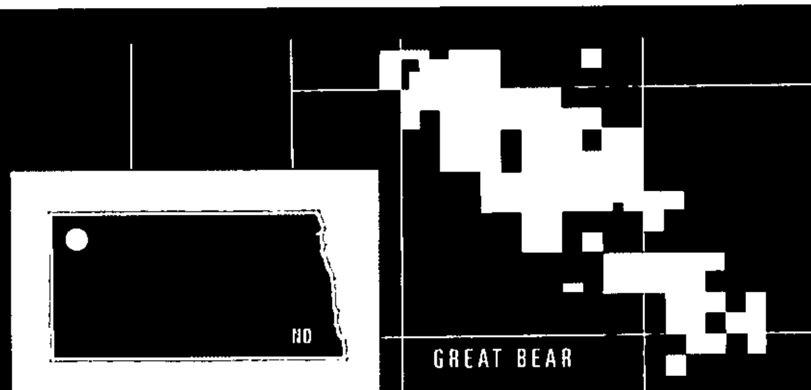
- Targeting limestones and dolomites in Paleozoic-aged oil-bearing formations
- Prospects are 2-D and 3-D defined
- Provides stable, predictable cash flow in high crude oil price environment
- State and fee leasehold is desirable for permitting and year-round operations
- 50% average working interest, 100% operated
- 25,150 net Montana acres; 13,062 net North Dakota acres

2006 Activity

- Invested $16.3 million to drill 4 gross (2.38 net) wells
- Continued adding to acreage position
- Shot seismic, reprocessed seismic and identified an inventory of Mission Canyon, Bakken and Red River locations

2007 Plans

- $15.75 million CAPEX targets 6 (3 net) Mission Canyon/Red River and 3 (1.88 net) Bakken wells
- $3 million seismic program will help identify new play concepts and locations
- Seek additional acquisition opportunities and undeveloped acreage



THE WILLISTON BASIN CONTINUES TO PROVIDE MEANINGFUL CASH FLOW
AS KODIAK PLANS TO DRILL SEVEN NET VERMILLION BASIN WELLS IN 2007 TO FURTHER TEST
THE PRODUCTIVE POTENTIAL OF THE BAXTER, FRONTIER AND DAKOTA FORMATIONS.

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

FORM 10-K

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

For the fiscal year ended December 31, 2006
Commission file number: 001-32920

KODIAK
OIL & GAS CORP.

(Exact name of registrant as specified in its charter)

Yukon Territory (State or other jurisdiction of incorporation or organization)	**N/A** (I.R.S. Employer Identification No.)
1625 Broadway, Suite 330 **Denver, Colorado 80202** (Address of principal executive offices)	**(303) 592-8075** (Registrant's telephone number, including area code)

Securities pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock	**American Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act:

Title of Each Class
N/A

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

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

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

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

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

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ☐ NO ☒

At June 30, 2006, the aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $322,820,107.

The number of shares of the registrant's Common Stock outstanding as of March 12, 2007 was 87,548,426.

DOCUMENTS INCORPORATED BY REFERENCE

Certain portions of the registrant's definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A not later than April 30, 2007, in connection with the Registrant's 2007 Annual Meeting of Shareholders, are incorporated herein by reference into Part III of this Annual Report on Form 10-K.

KODIAK OIL & GAS CORP.
FORM 10-K
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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Form 10-K under "Item 1. Business," "Item 2. Properties," "Item 3. Legal Proceedings," and "Item 7. Management's Discussion and Analysis" and other factors may cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others, the following: general economic and business conditions, competition; success of operating initiatives; the success of the Company's exploration and development operations on its properties, the Company's ability to raise capital and the terms thereof, the acquisition of additional properties; the continuity, experience and quality of the Company's management; changes in or failure to comply with government regulations or the lack of government authorization to continue the Company's projects, and other factors referenced in this Form 10-K. The use in this Form 10-K of such words as "believes," "plans," "anticipates," "expects," "intends" and similar expressions are intended to identify forward-looking statements, but are not the exclusive means of identifying such statements. The success of the Company is dependent on the efforts of the Company, its employees and many other factors including, primarily, its ability to raise additional capital and establishing the economic viability of its exploration properties.

PART I

ITEM 1. BUSINESS

General Development of the Business

We were incorporated as a company on March 17, 1972 in the Province of British Columbia, Canada, under the name "Pacific Talc Ltd." pursuant to the Company Act (British Columbia). On November 12, 1998, we changed our name to "Columbia Copper Company Ltd." and consolidated our share capital on the basis of four old shares for one new share. On September 28, 2001, we were continued from British Columbia to the Yukon Territory and changed our name to "Kodiak Oil & Gas Corp." On September 23, 2003 we incorporated a wholly-owned subsidiary, Kodiak Oil & Gas (USA) Inc., in Colorado to hold all of our U.S. oil and natural gas properties. Our current management acquired control of our company early in 2001.

Our common shares began trading on the TSX Venture Exchange on September 28, 2001 and on the American Stock Exchange on June 21, 2006. Unless otherwise indicated, all dollar amounts reported in this 10-K are United States dollars.

Our principal executive offices are located at 1625 Broadway, Suite 330, Denver, Colorado 80202, and our telephone number is (303) 592-8075. We maintain a website at http://www.kodiakog.com. The information contained on or accessible through our website is not part of this 10-K.

In March 2006, we raised net proceeds of $36,537,239 in a private placement of 19,514,268 shares of common stock to accredited investors. We have used a portion of the net proceeds, and expect to use the remainder, to fund exploration and drilling programs and for working capital and general corporate purposes.

In December 2006, we raised net proceeds of $46,672,212 in a public offering of 12,075,000 shares of common stock. We expect to use the net proceeds to fund a portion of our 2007 exploration and drilling programs and for working capital and general corporate purposes.

Narrative Description of the Business

We are an independent energy company focused on the exploration, exploitation, acquisition and production of natural gas and crude oil in the United States. Our oil and natural gas reserves and operations are concentrated in two Rocky Mountain Basins. Our corporate strategy is to internally identify prospects, acquire lands encompassing those prospects and evaluate those prospects using subsurface geology and geophysical data and exploratory drilling. Using this strategy, we have developed a portfolio of proved reserves, development and exploratory drilling opportunities on conventional and non-conventional oil and natural gas prospects.

Generally, the demand for and the price of natural gas increase during the colder winter months and decrease during the warmer summer months. Pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Crude oil and the demand for heating oil are also impacted by seasonal factors, with generally higher prices in the winter. Seasonal anomalies, such as mild winters, sometimes lessen these fluctuations.

Our results of operations and financial condition are significantly affected by oil and natural gas commodity prices, which can fluctuate dramatically. Commodity prices are beyond our control and are difficult to predict. We do not currently hedge any of our production. The oil and natural gas volumes that we produced and the prices that we received for that production for the years ended December 31, 2006 and 2005 are set forth below.

	Fiscal Year ended December 31,	
	2006	**2005**
Volume:		
Gas (Mcf)	116,316	31,751
Liquids (Mcf)	1,008	0
Oil (Bbls)	61,966	2,699
Price:		
Gas (Mcf)	$ 5.56	$ 7.11
Liquids (Gls)	$ 10.24	$ 0
Oil (Bbls)	$ 55.52	$ 51.89

The oil and gas industry is intensely competitive, particularly with respect to the acquisition of prospective oil and natural gas properties and oil and natural gas reserves. Our ability to effectively compete is dependent on our geological, geophysical and engineering expertise, and our financial resources. We must compete against a substantial number of major and independent oil and natural gas companies that have larger technical staffs and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also have refining operations, market refined products and generate electricity. We also compete with other oil and natural gas companies to secure drilling rigs and other equipment necessary for drilling and completion of wells. Consequently, drilling equipment may be in short supply from time to time. Currently, access to additional drilling equipment in certain regions is difficult.

The prices received for domestic production of oil and natural gas have increased significantly during the past several years, and are continuing to increase in response to global political issues and domestic shortages, which has resulted in increased demand for the equipment and services that we need to drill, complete and operate wells. As a result of this increased demand for oil field services, shortages have developed, and we have seen an escalation in drilling rig rates, field service costs, material prices and all costs associated with drilling, completing and operating wells. If oil and natural gas prices remain high relative to historical levels, we anticipate that the recent trends toward increasing costs and equipment shortages will continue.

Our oil and natural gas exploration, production and related operations, when developed, are subject to extensive rules and regulations promulgated by federal, state, tribal and local authorities and agencies. For example, some states in which we may operate require permits for drilling operations, drilling bonds and reports concerning operations, and impose other requirements relating to the exploration for and production of oil and natural gas. Such states may also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from wells, and the regulation of spacing, plugging and abandonment of wells. Failure to comply with any such rules and regulations can result in substantial penalties. The increasing regulatory burden on the oil and natural gas industry will most likely increase our cost of doing business and may affect our profitability. Although we believe we are currently in substantial compliance with all applicable laws and regulations, we are unable to predict the future cost or impact of complying with such laws because such rules and regulations are frequently amended or reinterpreted. We may be required to make significant expenditures to comply with governmental laws and regulations, which could have a material adverse effect on our business, financial condition and results of operations.

Our operations are subject to various types of regulation at the federal, state and local levels that:

- require certain permits for the drilling of wells, including permits to drill wells on federal lands, which generally require a minimum of 60-120 days and permits to drill wells on state land and fee lands, which generally require a minimum of 30-60 days;

- mandate that we maintain bonding requirements in order to drill or operate wells; and

- regulate the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, temporary storage tank operations, air emissions from flaring, compression, and access roads, sour gas management, and the disposal of fluids used in connection with operations.

Our operations are also subject to various conservation laws and regulations. These regulations govern the size of drilling and spacing units or proration units, the density of wells that may be drilled in oil and natural gas properties, and the unitization or pooling of natural gas and oil properties. In this regard, some states allow the forced pooling or integration of lands and leases to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is primarily or exclusively voluntary, it may be more difficult to form units and therefore more difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose specified requirements regarding the ratability of production. On some occasions, tribal and local authorities have imposed moratoria or other restrictions on exploration and production activities that must be addressed before those activities can proceed. The effect of all these regulations may limit the amount of oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. Where our operations are located on federal lands, the timing and scope of development may be limited by the National Environmental Policy Act, or environmental or species protection laws and regulations. The regulatory burden on the oil and natural gas industry increases our costs of doing business and, consequently, affects our profitability. Because these laws and regulations are frequently expanded, amended and reinterpreted, we are unable to predict the future cost or impact of complying with applicable environmental and conservation requirements.

The Federal Energy Regulatory Commission, or FERC, regulates interstate natural gas transportation rates and service conditions. Its regulations affect the marketing of natural gas produced by us, as well as the revenues that may be received by us for sales of such production. Since the mid-1980's, FERC has issued a series of orders, culminating in Order Nos. 636, 636-A and 636-B (collectively, Order 636) that have significantly altered the marketing and transportation of natural gas. Order 636 mandated a fundamental restructuring of interstate pipeline sales and transportation service, including the unbundling by interstate pipelines of the sale, transportation, storage and other services such pipelines previously performed. One of FERC's purposes in issuing Order 636 was to increase competition within the natural gas industry. The United States Court of Appeals for the District of Columbia Circuit has largely upheld Order 636 and the Supreme Court declined to hear the appeal from that decision. Generally, Order 636 has eliminated or substantially reduced the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation service, and has substantially increased competition and volatility in natural gas markets.

The price we receive from the sale of oil and natural gas liquids will be affected by the cost of transporting products to markets. Effective January 1, 1995, FERC implemented regulations establishing an indexing system for transportation rates for oil pipelines, which, generally, index such rates to inflation, subject to certain conditions and limitations. We are not able to predict with certainty the effect, if any, of these regulations on our intended operations. The regulations may, however, increase transportation costs or reduce well head prices for oil and natural gas liquids.

Our operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment, and relating to safety and health. The recent trend in environmental legislation and regulation generally is toward stricter standards, and we expect that this trend will continue. These laws and regulations:

- require the acquisition of permits or other authorizations before construction, drilling and certain other activities;
- limit or prohibit construction, drilling and other activities on specified lands within wilderness and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

The permits required for our operations may be subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce their regulations, and violations are subject to fines or injunctions, or both. We believe that we are in substantial compliance with current applicable environmental laws and regulations, and have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on us, as well as the oil and natural gas industry in general.

The Comprehensive Environmental, Response, Compensation, and Liability Act, or CERCLA, and comparable state statutes impose strict, joint and several liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. The Federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize the imposition of substantial fines and penalties for noncompliance. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," state laws affecting our operations may impose clean-up liability relating to petroleum and petroleum-related products. In addition, although RCRA classifies certain oil field wastes as "non-hazardous," such exploration and production wastes could be reclassified as hazardous wastes thereby making such wastes subject to more stringent handling and disposal requirements. CERCLA, RCRA and comparable state statutes can impose liability for clean-up of sites and disposal of substances found on drilling and production sites long after operations on such sites have been completed.

The Endangered Species Act, or ESA, seeks to ensure that activities do not jeopardize endangered or threatened animal, fish and plant species, or destroy or modify the critical habitat of such species. Under the ESA, exploration and production operations, as well as actions by federal agencies, may not significantly impair or jeopardize the species or its habitat. The ESA has been used to prevent or delay drilling activities and provides for criminal penalties for willful violations of its provisions. Other statutes that provide protection to animal and plant species and that may apply to our operations include, without limitation, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act, the National Historic Preservation Act and often their state, tribal or local counterparts. Projects can be denied or significantly modified to accommodate tribal burial sites, archeological sites or other historical sites. The National Environmental Policy Act, or NEPA, requires a thorough review of the environmental impacts of "major federal actions" and a determination of whether proposed actions on federal land would result in "significant impact." For purposes of NEPA, "major federal action" can be something as basic as issuance of a required permit. For oil and gas operations on federal lands or requiring federal permits, NEPA review can increase the time for obtaining approval and impose additional regulatory burdens on the natural gas and oil industry, thereby increasing our costs of doing business and our profitability. Although we believe that our operations are in substantial compliance with these statutes, any change in these statutes or any reclassification of a species as threatened or endangered or re-determination of the extent of "critical habit" could subject us to significant expenses to modify our operations or could force us to discontinue some operations altogether. Any new or additional NEPA analysis could also result in significant changes.

The Company has not incurred, and does not currently anticipate incurring, any material capital expenditures for environmental control facilities

As of December 31, 2006, we employed twelve full-time employees.

Financial Information about Geographic Areas

We derived natural gas production revenues of $718,925 and oil production revenues of $3,440,182 for the year ended December 31, 2006. Most of our gas production comes from six wells in the Green River Basin, three of which we operate and in three of which we have a non-operating economic interest. Our oil revenues are derived primarily from eight wells that we operate in the Williston Basin. As of December 31, 2006, we owned natural gas and oil leasehold interests covering approximately 123,371 gross acres and 80,128 net acres, of which 118,731 gross acres and 77,416 net acres are undeveloped.

Available Information

We make available, free of charge through our website, our annual report on Form 10-K, quarterly reports on Form 10-Q and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after such documents are electronically filed with, or furnished to, the SEC. Our internet address is http://www.kodiakog.com.

Capital Expenditures

We anticipate capital expenditures of $60 million in 2007 compared to capital expenditures of about $37 million in 2006. The following tables set forth our capital expenditures for the year ended December 31, 2006 and our planned capital expenditures for our principal properties in 2007.

Project Location	Working Interest (WI)	Gross Wells	Net Wells	Fiscal Year Ended 2006 Capital Expenditures
Green River Basin				
Vermillion Basin Shallow	50.0%	3	1.50	3,063,000
Vermillion Basin Deep	100%	2	2.00	8,000,000
Acreage/Seismic				931,000
Total Green River Basin		5	3.50	$20,462,000
Williston Basin				
Mission Canyon/Red River	50.0%	1	.50	4,212,000
Bakken	62.5%	3	1.88	11,121,000
Acreage/Seismic				931,000
Total Williston Basin		4	2.38	16,264,000
Total Kodiak Oil & Gas		9	5.88	$36,726,000

Our preliminary 2007 capital expenditures budget is approximately $60 million. The following table sets forth our planned capital expenditures for our principal properties in 2007:

Prospect Location	WI	Gross Wells	Net Wells	Estimated 2007 Expenditures
Green River Basin				
Vermillion Deep Operated	100.0%	7	7.00	31,500,000
Vermillion Deep Non-Op	25.0%	2	0.50	2,250,000
Other Projects	50.0%	2	1.00	2,500,000
Acreage/Seismic				5,000,000
Total Green River Basin		**11**	**8.50**	**$41,250,000**
Williston Basin				
Mission Canyon / Red River	50.0%	6	3.00	6,000,000
Bakken	62.5%	3	1.88	9,750,000
Acreage/Seismic				3,000,000
Total Williston Basin		**9**	**4.88**	**18,750,000**
Total Kodiak Oil & Gas		**20**	**13.38**	**$ 60,000,000**

Drilling Activity

All of our drilling activities are conducted on a contract basis by independent drilling contractors. We do not own any drilling equipment. The following table sets forth the number and type of wells that we drilled during the year ended December 31, 2006.

	2006	
	Gross	Net
Development:		
Oil	3	1.88
Gas	3	1.50
Non-Productive	0	0
Exploratory:		
Oil	0	0
Gas	2	2.0
Non-Productive	1	0.5
Total	**9**	**5.88**

As part of our corporate strategy, we plan to seek to operate our wells where possible and to maintain a high level of participation in our wells by investing our own capital in drilling operations. To date, our company has drilled two wells in the Green River Basin and eleven wells in the Williston Basin. Currently, we operate three wells in the Green River Basin and eight wells in the Williston Basin.

ITEM 1A. RISK FACTORS

Investing in shares of our common stock is highly speculative and involves a high degree of risk. In addition to the other information included in this Form 10-K, you should carefully consider the risks described below before purchasing shares of our common stock. If any of the following risks actually occur, our business, financial condition and results of operations could materially suffer. As a result, the trading price of our common stock could decline, and you might lose all or part of your investment.

Risks Relating to the Company

We will require significant additional capital, which may not be available to us on favorable terms, or at all.

We will need to expend significant capital in order to explore and develop our properties. Our plan of operation for 2007 contemplates capital expenditures of $60 million for the development of existing properties and anticipated property acquisitions. If our available sources of liquidity are insufficient to fund our expected capital needs for 2007, or our needs are greater than anticipated, we will be required to raise additional funds in the future through private or public sales of equity securities or the incurrence of indebtedness. In addition, we will be required to raise additional funds in the future to fund our plan of operation beyond 2007.

There can be no assurance that we will obtain necessary additional financing on favorable terms or at all. If we borrow additional funds, we likely will be obligated to make periodic interest or other debt service payments and may be subject to additional restrictive covenants. Should we elect to raise additional capital through the issuance and sale of equity securities, the sales may be at prices below the market price of our stock, and our shareholders may suffer significant dilution. Our failure to obtain financing on a timely basis or on favorable terms could result in the loss or substantial dilution of our interests in our properties as disclosed in this Form 10-K. In addition, the failure of any of our joint venture partners to obtain any required financing could adversely affect our ability to complete the exploration or development of any of our joint venture projects on a timely basis.

We have historically incurred losses and expect to incur additional losses in the future. It is difficult for us to forecast when we will achieve profitability, if ever.

We have historically incurred losses from operations during our limited history in the oil and natural gas business. As at December 31, 2006, we had a cumulative deficit of $8,615,667. While we have developed some of our properties, most of our properties are in the exploration stage and to date we have established a limited volume of proved reserves on our properties. To become profitable, we would need to be successful in our acquisition, exploration, development and production activities, all of which are subject to many risks beyond our control. We cannot assure you that we will successfully implement our business plan or that we will achieve commercial profitability in the future. Even if we become profitable, we cannot assure you that our profitability will be sustainable or increase on a periodic basis. In addition, should we be unable to continue as a going concern, realization of assets and settlement of liabilities in other than the normal course of business may be at amounts significantly different from those in the financial statements included in this Form 10-K. Finally, due to our limited history in the oil and natural gas business, we have limited historical financial and operating information available to help you evaluate our performance or an investment in our common stock.

We may not be able to successfully drill wells that can produce oil or natural gas in commercially viable quantities.

We cannot assure you that we will be able to successfully drill wells that can produce commercial quantities of oil and natural gas in the future. The total cost of drilling, completing and operating a well is uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. Further, many factors may curtail, delay or cancel drilling, including the following:

- our limited history of drilling wells;
- delays and restrictions imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;

- adverse weather conditions;
- reductions in oil and natural gas prices;
- land title problems; and
- limitations in the market for oil and natural gas.

The occurrence of any of these events could negatively affect our ability to successfully drill wells that can produce oil or natural gas in commercially viable quantities.

The actual quantities and present value of our proved reserves may be lower than we have estimated.

This Form 10-K contains estimates of our proved oil and natural gas reserves and the estimated future net revenues from these reserves. The process of estimating oil and natural gas reserves is complex and requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Accordingly, these estimates are inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, development and operating expenses, and quantities of recoverable oil and natural gas reserves most likely will vary from these estimates and vary over time. Such variations may be significant and could materially affect the estimated quantities and present value of our proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, results of secondary and tertiary recovery applications, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues referred to in this Form 10-K is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any change in consumption by oil or natural gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of our oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor nor does it reflect discount factors used in the market place for the purchase and sale of oil and natural gas.

Our interests are held in the form of leases that we may be unable to retain.

Our properties are held under leases, and working interests in leases. Generally, the leases we are a party to are for a fixed term, but contain a provision that allows us to extend the term of the lease so long as we are producing oil or natural gas in quantities to meet the required payments under the lease. If we or the holder of a lease fails to meet the specific requirements of the lease regarding delay rental payments, continuous production or development, or similar terms, portions of the lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each lease will be met. The termination or expiration of our leases or the working interests relating to leases may reduce our opportunity to exploit a given prospect for oil and natural gas production and thus have a material adverse effect on our business, results of operation and financial condition.

We have limited control over activities in properties we do not operate, which could reduce our production and revenues.

We do not operate all of the properties in which we have an interest. As of December 31, 2006, we owned a non-operating interest in six wells in the Vermillion Basin and may acquire non-operating interests in additional wells in the future. As a result, we may have a limited ability to exercise influence over normal operating procedures, expenditures or future development of underlying properties and their associated costs. For all of the properties that are operated by others, we are dependent on their decision-making with respect to day-to-day operations over which we have little control. The failure of an operator of wells in which we have an interest to adequately perform operations, or an operator's breach of applicable agreements, could reduce production and revenues we receive from that well. The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including:

- timing and amount of capital expenditures;
- expertise and financial resources; and
- inclusion of other participants.

We have a limited experience as an operator of wells.

We are an independent energy company with a limited operating history and limited experience in drilling and operating wells in the Green River Basin and the Williston Basin. We currently conduct some of our oil and natural gas exploration, development and production activities in joint ventures with others. As part of our corporate strategy, we plan to seek to operate our wells where possible and to maintain a high level of participation in our wells by investing our own capital in drilling operations. While our management team has considerable industry experience, to date our company has drilled only two wells in the Green River Basin and eleven wells in the Williston Basin. Currently, we operate only three wells in the Green River Basin and eight wells in the Williston Basin. If we fail to successfully manage our drilling and exploration programs or fail to successfully operate our wells, we may never become profitable.

The title to our properties may be defective.

It is our practice in acquiring oil and natural gas leases or interests in oil and natural gas leases not to undergo the expense of retaining lawyers to fully examine the title to the interest to be placed under lease or already placed under lease. Rather, we rely upon the judgment of oil and natural gas lease brokers or landmen who actually do the field work in examining records in the appropriate governmental office before attempting to place under lease a specific interest. We believe that this practice is widely followed in the oil and natural gas industry.

Prior to drilling a well for oil and natural gas, it is the normal practice in the oil and natural gas industry for the person or company acting as the operator of the well to hire a lawyer to examine the title to the unit within which the proposed oil and natural gas well is to be drilled. Frequently, as a result of such examination, curative work must be done to correct deficiencies in the marketability of the title. The work entails expense and might include obtaining an affidavit of heirship or causing an estate to be administered. The examination made by the title lawyers may reveal that the oil and natural gas lease or leases are worthless, having been purchased in error from a person who is not the owner of the mineral interest desired. In such instances, the amount paid for such oil and natural gas lease or leases may be lost.

Our officers and directors may become subject to conflicts of interest.

Some of our directors and officers may also become directors, officers, contractors, shareholders or employees of other companies engaged in oil and natural gas exploration and development. To the extent that such other companies may participate in ventures in which we may participate, our directors may have a conflict of interest in negotiating and concluding terms respecting the extent of such participation. In the event that such a conflict of interest arises at a meeting of our directors, a director who has such a conflict will declare his interest and abstain from voting for or against the approval of such participation or such terms. In appropriate cases, we will establish a special committee of independent directors to review a matter in which several directors, or management, may have a conflict. From time to time, several companies may participate in the acquisition, exploration and development of oil and natural gas properties thereby allowing for their participation in larger programs, permitting involvement in a greater number of programs and reducing financial exposure in respect of any one program. A particular company may assign all or a portion of its interest in a particular program to another of these companies due to the financial position of the company making the assignment.

In accordance with the laws of the Yukon Territory, our directors are required to act honestly, in good faith and in the best interests of our company. In determining whether or not we will participate or acquire an interest in a particular program, our officers will primarily consider the potential benefits to our company, the degree of risk to which we may be exposed and our financial position at the time. See "Related Party Transactions."

We depend on our current management team, the loss of any member of which could delay the further implementation of our business plan or cause business failure.

We are heavily dependent upon the expertise of our management team, especially our executive officers, Lynn Peterson and James Catlin. The loss of Mr. Peterson or Mr. Catlin would have a material adverse effect on us. Neither Mr. Peterson nor Mr. Catlin have entered into an employment agreement with us. We have obtained "key man" insurance for our management. In addition, the loss of the services of either of our executive officers, or any other member of our management team, through incapacity or otherwise, would be costly to us and would require us to seek and retain other qualified personnel. We cannot assure you that we could find a suitable replacement for any member of our management team. See "Management."

Oil and natural gas reserves decline once a property becomes productive, and we may need to find new reserves to sustain revenue growth.

Even if we add oil and natural gas reserves through our exploration activities, our reserves will decline as they are produced. We will be constantly challenged to add new reserves through further exploration and development of our existing properties. We cannot assure you that our exploration and development activities will be successful in adding new reserves. If we fail to replace reserves, our business, results of operations and financial condition will be adversely impacted.

We will need to make substantial financial and man-power investments in order to assess our internal controls over financial reporting and our internal controls over financial reporting may be found to be deficient.

Section 404 of the Sarbanes-Oxley Act of 2002 requires management to assess our internal controls over financial reporting and requires auditors to attest to that assessment. Current regulations of the Securities and Exchange Commission, or SEC, will require us to include this assessment and attestation in our annual report commencing with the annual report we file with the SEC for our fiscal year ended December 31, 2007.

We will incur significant increased costs in implementing and responding to these requirements. In particular, the rules governing the standards that must be met for management to assess its internal controls over financial reporting under Section 404 are complex, and require significant documentation, testing and possible remediation. Our process of reviewing, documenting and testing our internal controls over financial reporting may cause a significant strain on our management, information systems and resources. We may have to invest in additional accounting and software systems. We may be required to hire additional personnel and to use outside legal, accounting and advisory services. In addition, we will incur additional fees from our auditors as they perform the additional services necessary for them to provide their attestation. If we are unable to favorably assess the effectiveness of our internal control over financial reporting when we are required to, or if our independent auditors are unable to provide an unqualified attestation report on such assessment, we may be required to change our internal control over financial reporting to remediate deficiencies. In addition, investors may lose confidence in the reliability of our financial statements causing our stock price to decline.

Our focus on exploration activities exposes us to greater risks than are generally encountered in later-stage oil and natural gas property development businesses.

Much of our current activity involves drilling exploratory wells on properties with no proved oil and natural gas reserves. While all drilling, whether developmental or exploratory, involves risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of oil and natural gas. The economic success of any project will depend on numerous factors, including:

- our ability to drill, complete and operate wells;
- our ability to estimate the volumes of recoverable reserves relating to individual projects;
- rates of future production;
- future commodity prices; and

- investment and operating costs and possible environmental liabilities.

All of these factors may impact whether a project will generate cash flows sufficient to provide a suitable return on investment. If we experience a series of failed drilling projects, our business, results of operations and financial condition could be materially adversely affected.

We rely on independent experts and technical or operational service providers over whom we may have limited control.

We use independent contractors to provide us with technical assistance and services. We rely upon the owners and operators of rigs and drilling equipment, and upon providers of field services, to drill and develop our prospects to production. In addition, we rely upon the services of other third parties to explore or analyze our prospects to determine a method in which the prospects may be developed in a cost-effective manner. Our limited control over the activities and business practices of these providers, any inability on our part to maintain satisfactory commercial relationships with them or their failure to provide quality services could materially and adversely affect our business, results of operations and financial condition.

We have not insured and cannot fully insure against all risks related to our operations, which could result in substantial claims for which we are underinsured or uninsured.

We have not insured and cannot fully insure against all risks and have not attempted to insure fully against risks where coverage is prohibitively expensive. We do not carry business interruption insurance coverage. Our exploration, drilling and other activities are subject to risks such as:

- fires and explosions;
- environmental hazards, such as uncontrollable flows of natural gas, oil, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical failures of drilling equipment;
- personal injuries and death, including insufficient worker compensation coverage for third-party contractors who provide drilling services; and
- natural disasters, such as adverse weather conditions.

Losses and liabilities arising from uninsured and underinsured events, which could arise from even one catastrophic accident, could materially and adversely affect our business, results of operations and financial condition.

Properties that we acquire may not produce oil or natural gas as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them, which could cause us to incur losses.

One of our growth strategies is to pursue selective acquisitions of oil and natural gas reserves. If we choose to pursue an acquisition, we will perform a review of the target properties that we believe is consistent with industry practices. However, these reviews are inherently incomplete. Generally, it is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. We may not perform an inspection on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we may not be able to obtain effective contractual protection against all or part of those problems, and we may assume environmental and other risks and liabilities in connection with the acquired properties.

Our operations in North Dakota, Montana and Wyoming could be adversely affected by abnormally poor weather conditions.

Our operations in North Dakota, Montana and Wyoming are conducted in areas subject to extreme weather conditions and often in difficult terrain. Primarily in the winter and spring, our operations are often curtailed because of cold, snow and wet conditions. Unusually severe weather could further curtail these operations, including drilling of new wells or production from existing wells, and depending on the severity of the weather, could have a material adverse effect on our business, financial condition and results of operations.

In addition, our federal leases generally include restrictions on drilling during the period of November 15 to April 30. These restrictions are intended to protect big game winter habitat and not to restrict operations or maintenance of production facilities. To the extent that our exploration and drilling program on our federal leases cannot be completed during the period of May 1 through November 14, our drilling program may be delayed.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

We deliver oil and natural gas through gathering systems and pipelines that we do not own. These facilities may not be available to us in the future. Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder access to oil and natural gas markets or delay production, if any, at our wells. The availability of a ready market for our future oil and natural gas production will depend on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Any significant change in our arrangements with gathering system or pipeline owners and operators or other market factors affecting the overall infrastructure facilities servicing our properties would adversely affect our ability to deliver the oil and natural gas we produce to markets in an efficient manner.

Risks Relating to Our Industry

The oil and natural gas industry is subject to significant competition, which may increase costs or otherwise adversely affect our ability to compete.

Oil and natural gas exploration is intensely competitive and involves a high degree of risk. In our efforts to acquire oil and natural gas producing properties, we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also conduct refining and petroleum marketing operations on a worldwide basis. Our ability to compete for oil and natural gas producing properties will be affected by the amount of funds available to us, information available to us and any standards established by us for the minimum projected return on investment. Our products will also face competition from alternative fuel sources and technologies.

Oil and natural gas are commodities subject to price volatility based on many factors outside the control of producers, and low prices may make properties uneconomic for future production.

Oil and natural gas are commodities, and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices a producer may expect and its level of production depend on numerous factors beyond its control, such as:

- changes in global supply and demand for oil and natural gas;
- economic conditions in the United States and Canada;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- government regulation;
- the price and quantity of imports of foreign oil and natural gas;

- political conditions, including embargoes, in oil- and natural gas-producing regions;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease revenues on a per unit basis, but also may reduce the amount of oil and natural gas that can be economically produced. Lower prices will also negatively affect the value of proved reserves.

Exploration and drilling operations are subject to significant environmental regulation, which may increase costs or limit our ability to develop our properties.

We may encounter hazards incident to the exploration and development of oil and natural gas properties such as accidental spills or leakage of petroleum liquids and other unforeseen conditions. We may be subject to liability for pollution and other damages due to hazards that we cannot insure against due to prohibitive premium costs or for other reasons. Governmental regulations relating to environmental matters could also increase the cost of doing business or require alteration or cessation of operations in some areas.

Existing and possible future environmental legislation, regulations and actions could give rise to additional expense, capital expenditures, restrictions and delays in our activities, the extent of which we cannot predict. Regulatory requirements and environmental standards are subject to constant evaluation and may be significantly increased, which could materially and adversely affect our business or our ability to develop our properties on an economically feasible basis. Before development and production can commence on any properties, we must obtain regulatory and environmental approvals. We cannot assure you that we will obtain such approvals on a timely basis or at all. The cost of compliance with changes in governmental regulations has the potential to reduce the profitability of our operations and preclude entirely the economic development of a specific property.

A substantial or extended decline in oil and natural gas prices could reduce our future revenue and earnings.

As with most other companies involved in resource exploration and development, we may be adversely affected by future increases in the costs of conducting exploration, development and resource extraction that may not be fully offset by increases in the price received on sale of oil or natural gas.

Our revenues and growth, and the carrying value of our oil and natural gas properties are substantially dependent on prevailing prices of oil and natural gas. Our ability to obtain additional capital on attractive terms is also substantially dependent upon oil and natural gas prices. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include changes in global supply and demand for oil and natural gas, economic conditions in the United States and Canada, the actions of OPEC, governmental regulation, the price and quantity of imports in foreign oil- and natural gas-producing regions, political conditions, including embargoes in oil- and natural gas-producing regions, the level of global oil and natural gas inventories, weather conditions, technological advances affecting energy consumption and the price and availability of alternate fuel sources. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on our business, financial condition and results of operations.

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Local, national and international economic conditions are beyond our control and may have a substantial adverse effect on our efforts. We cannot guard against the effects of these potential adverse conditions.

Our operations and demand for our products are affected by seasonal factors, which may lead to fluctuations in our operating results.

Our operating results are likely to vary due to seasonal factors. Demand for oil and natural gas products will generally increase during the winter because they are often used as heating fuels. The amount of such increased demand will depend to some extent upon the severity of winter. Because of the seasonality of our business and continuous fluctuations in the prices of our products, our operating results are likely to fluctuate from period to period.

Conducting operations in the oil and natural gas industry subjects us to complex laws and regulations that can have a material adverse effect on the cost, manner and feasibility of doing business.

Companies that explore for and develop, produce and sell oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax and environmental laws and the corresponding regulations, and are required to obtain various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct our operations as planned. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- water discharge and disposal permits for drilling operations;
- drilling bonds;
- drilling permits;
- reports concerning operations;
- air quality, noise levels and related permits;
- spacing of wells;
- rights-of-way and easements;
- unitization and pooling of properties;
- gathering, transportation and marketing of oil and natural gas;
- taxation; and
- waste transport and disposal permits and requirements.

Failure to comply with these laws may result in the suspension or termination of operations and subject us to liabilities under administrative, civil and criminal penalties. Compliance costs can be significant. Moreover, these laws could change in ways that substantially increase the costs of doing business. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition and results of operations.

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

Due to domestic drilling activity increases, particularly in fields in which we operate, a general shortage of drilling rigs, equipment, supplies and personnel has developed. As a result, the costs and delivery times of rigs, equipment, supplies or personnel are substantially greater than in previous years. From time to time, these costs have sharply increased and could do so again. The demand for and wage rates of qualified drilling rig crews generally rise in response to the increasing number of active rigs in service and could increase sharply in the event of a shortage. Shortages of drilling rigs, equipment, supplies or personnel could delay or adversely affect our development operations, which could have a material adverse effect on our business, financial condition and results of operations.

Risks Relating to Our Common Stock

Our common stock has a limited trading history and may experience price volatility.

Our common stock has been trading on the TSX Venture Exchange, or TSX-V, since September 28, 2001, and on the American Stock Exchange, or AMEX, since June 21, 2006. The volume of trading in our common stock varies greatly and may often be light, resulting in what is known as a "thinly-traded" stock. Until a larger secondary market for our common stock develops, the price of our common stock may fluctuate substantially. The price of our common stock may also be impacted by any of the following, some of which may have little or no relation to our company or industry:

- the breadth of our stockholder base and extent to which securities professionals follow our common stock;
- investor perception of our Company and the oil and natural gas industry, including industry trends;
- domestic and international economic and capital market conditions, including fluctuations in commodity prices;
- responses to quarter-to-quarter variations in our results of operations;
- announcements of significant acquisitions, strategic alliances, joint ventures or capital commitments by us or our competitors;
- additions or departures of key personnel;
- sales or purchases of our common stock by large stockholders or our insiders;
- accounting pronouncements or changes in accounting rules that affect our financial reporting; and
- changes in legal and regulatory compliance unrelated to our performance.

We have not paid cash dividends on our common stock and do not anticipate paying any dividends on our common stock in the foreseeable future.

We do not anticipate paying cash dividends on our common stock in the foreseeable future. Payment of future cash dividends, if any, will be at the discretion of our board of directors and will depend on our financial condition, results of operations, contractual restrictions, capital requirements, business prospects and other factors that our board of directors considers relevant. Accordingly, investors may only see a return on their investment if the value of our securities appreciates.

Our constating documents permit us to issue an unlimited number of shares without shareholder approval.

Our Articles of Continuation permit us to issue an unlimited number of shares of our common stock. Subject to the requirements of any exchange on which we may be listed, we will not be required to obtain the approval of shareholders for the issuance of additional shares of our common stock. In 2005, we issued 20,671,875 shares of our common stock for net proceeds of $17,879,673. In 2006, we issued 31,589,268 shares of our common stock for net proceeds of $83,209,451. We anticipate that we will, from time to time, issue additional shares of our common stock to provide working capital for future operations. Any further issuances of shares of our common stock from our treasury will result in immediate dilution to existing shareholders and may have an adverse effect on the value of their shareholdings.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

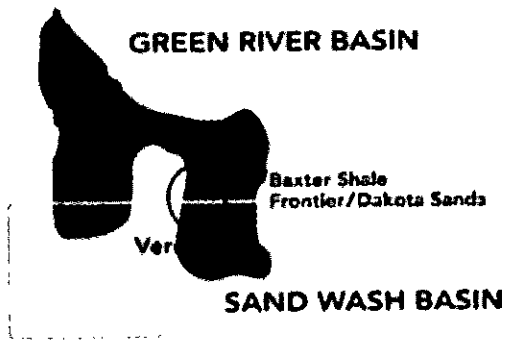
ITEM 2. PROPERTIES

Following are maps of our primary geological regions:

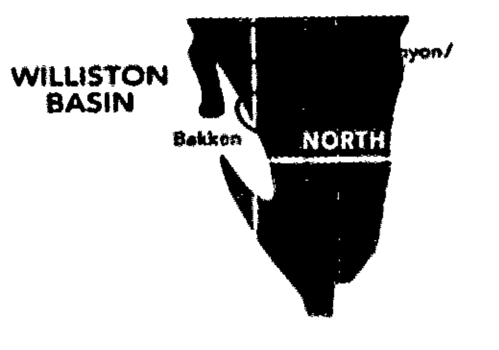
Kodiak Oil and Gas Corp.

Groon River Basin and Williston Basin

Groon Rivor Basin



Williston Basin



We have focused our exploration on two geographic areas in the Rocky Mountain Region of the United States. We explore for conventional and unconventional gas plays in the Green River Basin in Wyoming and Colorado, and for oil in the Williston Basin in Montana and North Dakota. Existing oil and natural gas pipeline infrastructure is of critical importance to us in identifying our prospects. In most cases, our natural gas prospects are within a reasonable distance of natural gas pipelines, therefore limiting the construction of gathering systems necessary to tie into existing lines. Our oil is transported mostly by trucks and, if available, pipelines.

Leasing and Property Acquisition Activities

As at December 31, 2006, we had several hundred lease agreements representing approximately 123,371 gross acres and 80,128 net acres. Our leases are located in the Williston Basin in Montana and North Dakota and the Green River Basin in Wyoming and Colorado. We have focused our leasing activities in areas that are serviced by existing pipeline systems and infrastructure.

The majority of our acreage located in the Green River Basin is federal land administered by the U.S. Bureau of Land Management, or the BLM. Typically these lands are acquired through a public auction and have a primary lease term of ten years. The U.S. Department of Interior normally retains a 12.5% royalty interest in these lands. Most of our lands in this area are encompassed within federal operating units approved by the BLM that allow for the orderly exploration and development of the federal lands. In most cases these federal lands require an annual delay rental of $1.50 per net acre.

Our acreage located in the Williston Basin is held primarily on the basis of fee leases. These leases typically carry a primary term three to five years with landowner royalties of 12.5% to 16.6%. In most cases we obtain "paid up" leases that do not require annual delay rentals.

All of our leases grant us the exclusive right to explore for and develop oil, natural gas and other hydrocarbons and minerals that may be produced from wells drilled on the leased property without any depth restrictions. We generally do not acquire leases under which our net revenue interest would be less than 80% of our working interest. Our federal leases generally include restrictions on drilling during the period of November 15 to April 30. These restrictions are intended to protect big game winter habitat and do not restrict operations or maintenance of production facilities.

The following table sets forth our gross and net acres of developed and undeveloped oil and natural gas leases as of December 31, 2006.

	Undeveloped Acreage(1)		**Developed Acreage(2)**		**Total Acreage**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Green River Basin						
Wyoming	53,796	34,541	1,280	752	55,076	35,293
Colorado	9,056	6,623	--	--	9,056	6,623
Williston Basin						
Montana	35,874	24,830	640	320	36,514	25,150
North Dakota	20,005	11,422	2,720	1,640	22,725	13,062
Acreage Totals	**118,731**	**77,416**	**4,640**	**2,712**	**123,371**	**80,128**

(1) Undeveloped acreage is lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage includes proved reserves.

(2) Developed acreage is the number of acres that are allocated or assignable to producing wells or wells capable of production.

Substantially all of the leases summarized in the preceding table will expire at the end of their respective primary terms unless the existing lease is renewed or we have obtained production from the acreage subject to the lease prior to the end of the primary term, in which event the lease will remain in effect until the cessation of production. The following table sets forth the gross and net acres of undeveloped land subject to leases summarized in the preceding table that will expire during the periods indicated:

Year Ending	Expiring Acreage Gross	Net
December 31, 2007	None	None
December 31, 2008	4,073	1,237
December 31, 2009	3,981	2,982
Total	8,054	4,219

Green River Basin —Wyoming and Colorado

Vermillion Basin Deep-Gas Project—Almond Sands, Baxter Shale and Frontier and Dakota Sandstone

Our primary leaseholdings in the Green River Basin are located in an area referred to as the Vermillion Basin. In this geologic region, we believe there is natural gas trapped in various sands, coals and shales at depths ranging from 2,000 feet to nearly 15,000 feet. The primary targets of our exploration efforts are the Almond sands at an approximate depth of 5,000 feet, the Ericson and Rock Springs sands between 6,000 and 10,000 feet, the Baxter shale at approximately 10,500 feet, the Frontier sandstones at 13,500 feet and the Dakota sandstones at 14,500 feet. During the past two years, another exploration and production company has drilled seventeen wells in the Vermillion Basin to evaluate the deeper natural gas potential of this area. We believe that all of these wells are producing hydrocarbons, and that the prospective natural gas bearing zones may be present over a very large geologic area, including most of the area where we have our leaseholds. Based upon the results of this drilling and other wells previously drilled to deeper horizons, we believe that the Baxter shale and the Frontier and Dakota sands are subject to high pressure, which has allowed gas to be produced in rocks with low permeability. While the total productive area and applicable production drainage are unknown, based on the exploration work of other producers in the Green River basin, we believe that 40-acre spacing may be appropriate for optimum drainage on this prospect. Using the 40-acre spacing pattern and based on the 41,845 gross acres (26,293 net) that we control, we may have the potential for several hundred locations. We have drilled and completed our first two operated wells in the prospect area. During fiscal 2007, we intend to drill or participate in drilling up to nine wells to evaluate the potential of the prospective zones.

While we have operated gas wells in the Green River Basin since November 2005, we only recently completed drilling our first two deep gas wells in the over-pressured formations in the Vermillion Basin area, the North Trail State #4-36 and NT #1-33 wells located in Sweetwater County, Wyoming. We operate and have a 100% working interest and 80% and 82.5% net revenue interest, respectively, in the wells. The wells were drilled to total depths of 14,330 feet and 14,500 respectively. With respect to NT #1-33, we completed fracture stimulation procedures over approximately 3,300 feet through nine different stages in early 2007. The NT #1-33 well tested at rates of approximately 2.0 million cubic feet per day of natural gas and has been producing between 1.0 and 2.0 million cubic feet per day into the sales line. Completion work continues on the North Trail State #4-36 well.

We have received eight approved drilling permits and expect to operate and drill five additional locations in the immediate area during 2007. We will begin this development program in April 2007 with the drilling of the NT #4-35 well followed by wells in the contiguous sections. Kodiak will have 100% working interest in most of the locations in the immediate area of our current drilling with net revenues of approximately 83%.

Six miles northwest of the North Trail #4-36 and four miles north of the NT #1-33, we have obtained a permit and built the location for the #1-8 CR Unit well. The proposed well will probably be drilled in the last half of the year to a total depth is 14,800 feet. We will operate and have an approximate 75% working interest and 62% net revenue interest in this well. We have begun the permitting process to complete a 3-D seismic program over our acreage in Township 14 North, Range 100 West. We anticipate that this program will be completed in the third quarter of 2007.

Southwest of this area, we have obtained an approved permit to drill the HB Unit #5-3 in our Horseshoe Basin Unit to test the Baxter Shale and Frontier and Dakota sandstones. The well will be drilled to a total depth of 13,750 feet. We are in the process of obtaining pipeline right-of-way, and we anticipate that drilling will commence in 2007, after the BLM winter lease stipulations expire. We expect to operate and have an approximate 65% working interest and 55% net revenue interest in the well.

Vermillion Basin Shallow—Almond Sandstone, Almond Coals and Ericson Sandstone

During the last part of 2007, we participated in the drilling of three non-operated shallow wells (50% WI) to test the Almond sands at an approximately depth of 5,500 feet. These wells were all placed into production in the first quarter of 2007 at rates between 440-600 Mcfg/d. These same sands are present in the deeper wells that we operated; however, we are currently not attempting to extract gas from the sands, but intend to produce from the sands at a later time. This development program is in the Chicken Springs Unit where we have an interest in three other wells that were completed in the Almond Sands during 2005.

Other Wyoming and Colorado Prospects

We have other geologic prospects that we have generated in Wyoming and are continuing to develop through seismic evaluation and exploratory and development drilling. In some cases we do not operate the properties and therefore cannot determine the time frame when the wells could be drilled. In most cases we do not own a controlling interest in the prospect area.

Sand Wash Basin Prospect Mancos Shale

Recently we acquired a 100% working interest in 7,800 gross and net acres in an exploratory Mancos Shale gas prospect located in the Sand Wash Basin in Moffat County, Colorado. We intend to commit additional capital to this exploratory project area in 2007 in the form of seismic exploration, land acquisition and potentially drilling.

Williston Basin - Montana and North Dakota

Our exploration efforts in the Williston Basin are concentrated on exploiting the oil and natural gas potential of the Mission Canyon Formation at an approximate depth of 8,000 feet, the Bakken Formation at 10,500 feet and the Red River Formation at 11,000 feet. We have acquired an interest in 59,239 gross acres and 38,212 net acres in the Basin. We operated one rig in the Williston Basin continuously during the last 22 months. The rig was released to another operator in February 2007, but we expect to have the same rig back under contract by April 2007.

Great Bear Prospect—Red River Dolomite

The Great Bear Prospect is located along the northwest flank of the Williston Basin in Divide County, North Dakota. The main reservoir objective is porous dolomite in the Ordovician Red River Formation.

The Pederson #9H well reached total depth in January 2006. Production facilities have been installed and the well was placed on pump in early September 2006 with inconclusive results. We reinterpreted the seismic data and have identified additional potential locations. We anticipate drilling at least one well on this prospect in 2nd quarter 2007. The well will initially be drilled vertically, after which we will evaluate whether a horizontal leg is warranted. We operate and have a 43.75% working and 35% net revenue interest in the well.

Cinnamon Bear Project—Mission Canyon (Carbonate) and Red River (Dolomite)

This area includes several prospects that have potential primarily for the Mission Canyon and Red River Formations. The initial test well on the Lowell Prospect, the State #8-16, was drilled to a depth of 7,700 feet to evaluate only the Mission Canyon Formation. We drilled three successful 160-acre offsets wells, the State #6-16, the State #10-16 and the Christensen Trust 15-9, in late 2005. Current field production from the four wells is approximately 400 BOPD and has been relatively stable for the past twelve months. In February 2007 we drilled a non-commercial well as a stepout to the existing wells and the well was plugged and abandoned. We operate and have a 50% working and 40% net revenue interest in the wells.

Further to the west, we recently completed a twenty square mile 3-D seismic program. The seismic data has been processed and evaluated, resulting in several geologic leads. We completed operations on the #2-13 Larsh well to evaluate the Mission Canyon Formation at an approximate depth of 8,000 feet and the Red River Formation at a depth of 11,000 feet in January 2007. We completed the well in the Red River Formation in February 2007 at an initial flowing rate of 232 BOPD. We operate and have a 50% working and 41.67% net revenue interest in the well. We are permitting two locations offsetting this discovery and expect to drill the wells in 3rd quarter 2007. We have also identified two other seismically defined features that we expect to drill in 2007.

Grizzly Prospect—Bakken Dolomite

Our lands are located in western McKenzie County, North Dakota near the Montana border and part of the Middle Bakken horizontal oil play. The Middle Bakken pay zone is a porous Devonian dolomite sandwiched between the upper Bakken Shale and either a thin lower Bakken shale or the Three Forks Formation. Wells in the zone are generally drilled with one to three 4,000-5,000-foot horizontal lateral well bores or occasionally one longer 8,000-9,000-foot lateral well bore.

The Kodiak Grizzly #13-6H was our first horizontal Bakken well that we began drilling in May 2006. We drilled to a depth of 10,500 feet with two lateral well bores totaling 9,000 feet. The well began producing oil in September 2006 and we fracture stimulated it in late 4th quarter 2006. We operate and have a 62.5% working and 54.7% net revenue interest in the well.

In October 2006, we completed the Grizzly Federal #4-11H well were we drilled three lateral well bores totaling 14,000 feet in the Bakken Formation. We operate and have a 62.5% working and 54.7% net revenue interest in the well.

We completed our third well, the Grizzly Federal #1-27H well, in December 2006. The well has a single well bore and is located three miles north of our Grizzly Federal #4-11H well. We completed drilling operations on the #1-27H well in December 2006 with one lateral well bore totaling 7,000 feet. We operate and have a 62.5% working and 53.0% net revenue interest in the well.

Cumulative production from the three wells through February 2007 was 38,712 BOPD. The remaining two wells will be fracture stimulated in early 2007 and pumping units will be installed.

Other Prospect—Bakken Dolomite

Approximately 80 miles east of our producing Grizzly wells we have acquired 7,800 gross and net acres in an area that we believe has the potential for Bakken production. Other exploration companies have established production to the north, south, and west of the acquired lands. We have acquired several seismic lines in the immediate area and will interpret the seismic prior to the commencement of drilling operations that are expected to begin in late 2007.

Our Reserves

Netherland Sewell & Associates, Inc., a petroleum engineering consulting firm, estimated our reserves as of December 31, 2006. Sproule Associates Inc., a petroleum engineering consulting firm, estimated our reserves as of December 31, 2005. All of our reserves are located within the continental United States. The reserve estimates are developed using geological and engineering data and interests and burdens information developed by our company. Reserve estimates are inherently imprecise and remain subject to revisions based on production history, results of additional exploration and development drilling results of secondary and tertiary recovery applications, prevailing oil and natural gas prices, and other factors. You should read the notes following the table below and the information contained in note 9 to our audited financial statements for the years ended December 31, 2006 and 2005 included elsewhere in this 10-K in conjunction with the following reserve estimates:

	As of December 31, 2006	2005
Proved Developed Oil Reserves (Thousands of Barrels, or MBbls)	493.3	309.4
Proved Undeveloped Oil Reserves (MBbls)	39.6	212.3
Total Proved Oil Reserves (MBbls)	532.9	521.7
Proved Developed Gas Reserves (Million Cubic Feet, or MMcf)	2,399.4	1,828.6
Proved Undeveloped Gas Reserves (MMcf)	3.0	1,006.6
Total Proved Gas Reserves (MMcf)	2,402.4	2,835.2
Total Proved Gas Equivalents (Million Cubic Feet Equivalent, or MMcfe)[1]	5,598.6	5,965.4
Present Value of Estimated Future Net Revenues Before Income Taxes, Discounted at 10%[2]	$19,668,200	$18,157,000
Present Value of Estimated Future Net Revenues After Income Taxes, Discounted at 10%[3]	$19,668,200	$14,202,800

(1) We converted oil to Mcf of gas equivalent at a ratio of one barrel to six Mcf.

(2) We calculated the present value of estimated future net revenues as of December 31, 2006 and 2005 using oil and natural gas prices that were received by each respective property as of that date. The average prices that we utilized for December 31, 2006 and 2005 were $4.53 and $7.88 per Mcf and $50.37 and $55.29 per barrel of oil, respectively.

(3) The Present Value of Estimated Future Net Revenues After Income Taxes, Discounted at 10%, is referred to as the "Standardized Measure." There is no tax effect in 2006 as the tax basis in properties and net operating loss exceeds the future net revenues. See Note 9 to our audited financial statements for the years ended December 31, 2006 and 2005.

ITEM 3. LEGAL PROCEEDINGS

We have no material legal proceedings pending, and we do not know of any material proceedings contemplated by governmental authorities. There are no material proceedings to which any director, officer or any of our affiliates, any owner of record or beneficially of more than five percent of any class of our voting securities, or any associate of any such director, officer, our affiliates, or security holder, is a party adverse to us or our consolidated subsidiary or has a material interest adverse to us or our consolidated subsidiary.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not Applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON STOCK, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information

Shares of our common stock, no par value, are issued in registered form. The transfer agent for the shares is Computershare Trust Company Inc., 100 University Avenue, 9th Floor, Toronto, Ontario M5J 2Y1.

Our common stock has been listed and posted for trading on the TSX-V under our current name since September 28, 2001, and on the AMEX since June 21, 2006.

High and Low Prices for Each Quarter in the Last Two Fiscal Years

Period Ended	TSX-V High	TSX-V Low	AMEX High	AMEX Low
December 31, 2006	$5.41	$3.31	$4.60	$3.08
September 30, 2006	$5.05	$3.61	$4.65	$3.17
June 30, 2006	$5.05	$2.70	$4.06	$3.32
March 31, 2006	$3.48	$2.15	-	-
December 31, 2005	$2.40	$0.91	-	-
September 30, 2005	$1.05	$0.72	-	-
June 30, 2005	$1.12	$0.70	-	-
March 31, 2005	$1.26	$0.75	-	-

Holders

At February 28, 2007, there were 99 holders of record of the Company's Common Stock including 70 in the United States who collectively held 40,516,095 shares representing 46% of the total number of issued and outstanding shares.

Dividend Policy

We have never paid any cash dividends on our common stock and do not anticipate paying any dividends in the foreseeable future. Our current business plan is to retain any future earnings to finance the expansion and development of our business. Any future determination to pay cash dividends will be at the discretion of our board of directors, and will be dependent upon our financial condition, results of operations, capital requirements and other factors as our board may deem relevant at that time.

Securities Authorized for Issuance under Equity Compensation Plans

The Company has an Incentive Share Option Plan (the "Plan") that grants stock options to our directors, officers, employees and consultants. The Company's shareholders approved the Plan at the 2003 shareholders' meeting and have ratified the Plan at each annual shareholders' meeting thereafter. As of February 28, 2007, the Company has outstanding options to purchase 4,636,500 common shares at prices from $0.14 to $4.03.

Equity Compensation Plan Information as of December 31, 2006

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))
Equity compensation plans approved by security holders	4,636,500	$1.96	4,118,343
Equity compensation plans not approved by security holders	N/A	N/A	N/A
Total	4,636,500	$1.96	4,118,343

Exchange Controls

Canada has no system of exchange controls. There are no exchange restrictions on borrowing from foreign countries nor on the remittance of dividends, interest, royalties and similar payments, management fees, loan repayments, settlement of trade debts, or the repatriation of capital. However, any dividends remitted to U.S. Holders, as defined below, will be subject to withholding tax. See "Canadian Federal Income Tax Considerations."

Except as provided in the Investment Canada Act (the "Act"), as amended by the Canada-United States Free Trade Implementation Act (Canada) and the Canada-United States Free Trade Agreement, there are no limitations specific to the rights of non-Canadians to hold or vote our common stock under the laws of Canada or the Yukon Territory or in our charter documents. Our company is not a "Canadian business," as defined in the Act; therefore, the limitations in the Act do not apply to our company.

Material Income Tax Consequences

A brief description of certain provisions of the tax treaty between Canada and the United States is included below, together with a brief outline of certain taxes, including withholding provisions, to which United States security holders are subject under existing laws and regulations of Canada and the United States. The consequences, if any, of provincial, state and local taxes are not considered.

The following information is general and security holders should seek the advice of their own tax advisors, tax counsel or accountants with respect to the applicability or effect on their own individual circumstances of the matters referred to herein and of any provincial, state or local taxes.

U.S. Federal Income Tax Consequences

The following is a summary of certain material U.S. federal income tax consequences to a U.S. Holder (as defined below) arising from and relating to the acquisition, ownership, and disposition of common shares of the Company ("Common Shares").

This summary is for general information purposes only and does not purport to be a complete analysis or listing of all potential U.S. federal income tax consequences that may apply to a U.S. Holder as a result of the acquisition, ownership, and disposition of Common Shares. In addition, this summary does not take into account the individual facts and circumstances of any particular U.S. Holder that may affect the U.S. federal income tax consequences of the acquisition, ownership, and disposition of Common Shares. Accordingly, this summary is not intended to be, and should not be construed as, legal or U.S. federal income tax advice with respect to any U.S. Holder. Each U.S. Holder should consult its own tax advisor regarding the U.S. federal income, U.S. state and local, and foreign tax consequences of the acquisition, ownership, and disposition of Common Shares.

Scope of this Summary

Authorities

This summary is based on the Internal Revenue Code of 1986, as amended (the "Code"), Treasury Regulations (whether final, temporary, or proposed), published rulings of the Internal Revenue Service (the "IRS"), published administrative positions of the IRS, the Convention Between Canada and the United States of America with Respect to Taxes on Income and on Capital, signed September 26, 1980, as amended (the "Canada-U.S. Tax Convention"), and U.S. court decisions that are applicable and, in each case, as in effect and available, as of the date of this Form 10-K. Any of the authorities on which this summary is based could be changed in a material and adverse manner at any time, and any such change could be applied on a retroactive basis. This summary does not discuss the potential effects, whether adverse or beneficial, of any proposed legislation that, if enacted, could be applied on a retroactive basis.

U.S. Holders

For purposes of this summary, a "U.S. Holder" is a beneficial owner of Common Shares that, for U.S. federal income tax purposes, is (a) an individual who is a citizen or resident of the U.S., (b) a corporation, or any other entity classified as a corporation for U.S. federal income tax purposes, that is created or organized in or under the laws of the U.S., any state in the U.S., or the District of Columbia, (c) an estate if the income of such estate is subject to U.S. federal income tax regardless of the source of such income, or (d) a trust if (i) such trust has validly elected to be treated as a U.S. person for U.S. federal income tax purposes or (ii) a U.S. court is able to exercise primary supervision over the administration of such trust and one or more U.S. persons have the authority to control all substantial decisions of such trust.

Non-U.S. Holders

For purposes of this summary, a "non-U.S. Holder" is a beneficial owner of Common Shares other than a U.S. Holder. This summary does not address the U.S. federal income tax consequences of the acquisition, ownership, and disposition of Common Shares to non-U.S. Holders. Accordingly, a non-U.S. Holder should consult its own tax advisor regarding the U.S. federal income, U.S. state and local, and foreign tax consequences (including the potential application of and operation of any income tax treaties) of the acquisition, ownership, and disposition of Common Shares.

U.S. Holders Subject to Special U.S. Federal Income Tax Rules Not Addressed

This summary does not address the U.S. federal income tax consequences of the acquisition, ownership, and disposition of Common Shares to U.S. Holders that are subject to special provisions under the Code, including the following U.S. Holders: (a) U.S. Holders that are tax-exempt organizations, qualified retirement plans, individual retirement accounts, or other tax-deferred accounts; (b) U.S. Holders that are financial institutions, insurance companies, real estate investment trusts, or regulated investment companies; (c) U.S. Holders that are dealers in securities or currencies or U.S. Holders that are traders in securities that elect to apply a mark-to-market accounting method; (d) U.S. Holders that have a "functional currency" other than the U.S. dollar; (e) U.S. Holders that are liable for the alternative minimum tax under the Code; (f) U.S. Holders that own Common Shares as part of a straddle, hedging transaction, conversion transaction, constructive sale, or other arrangement involving more than one position; (g) U.S. Holders that acquired Common Shares in connection with the exercise of employee stock options or otherwise as compensation for services; (h) U.S. Holders that hold Common Shares other than as a capital asset within the meaning of Section 1221 of the Code; or (i) U.S. Holders that own (directly, indirectly, or constructively) 10% or more of the total combined voting power of all classes of shares of the Company entitled to vote. U.S. Holders that are subject to special provisions under the Code, including U.S. Holders described immediately above, should consult their own tax advisors regarding the U.S. federal income tax consequences of the acquisition, ownership, and disposition of Common Shares.

If an entity that is classified as a partnership for U.S. federal income tax purposes holds Common Shares, the U.S. federal income tax consequences of the acquisition, ownership, and disposition of Common Shares to such partnership and the partners of such partnership generally will depend on the activities of the partnership and the status of such partners. Partners of entities that are classified as partnerships for U.S. federal income tax purposes should consult their own tax advisors regarding the U.S. federal income tax consequences of the acquisition, ownership, and disposition of Common Shares.

Tax Consequences Other than U.S. Federal Income Tax Consequences Not Addressed

This summary does not address the U.S. state and local, U.S. federal estate and gift, or foreign tax consequences to U.S. Holders of the acquisition, ownership, and disposition of Common Shares. Each U.S. Holder should consult its own tax advisor regarding the U.S. state and local, U.S. federal estate and gift, and foreign tax consequences of the acquisition, ownership, and disposition of Common Shares.

U.S. Federal Income Tax Consequences of the Acquisition, Ownership, and Disposition of Common Shares

Distributions on Common Shares

General Taxation of Distributions

Subject to the "passive foreign investment company" rules discussed below, a U.S. Holder that receives a distribution, including a constructive distribution, with respect to the Common Shares will be required to include the amount of such distribution in gross income as a dividend (without reduction for any Canadian income tax withheld from such distribution) to the extent of the current or accumulated "earnings and profits" of the Company, as determined for U.S. federal income tax purposes. To the extent that a distribution exceeds the current and accumulated "earnings and profits" of the Company, such distribution will be treated (a) first, as a tax-free return of capital to the extent of a U.S. Holder's tax basis in the Common Shares and, (b) thereafter, as gain from the sale or exchange of such Common Shares. (See more detailed discussion at "Disposition of Common Shares" below).

Reduced Tax Rates for Certain Dividends

For taxable years beginning before January 1, 2011, a dividend paid by the Company generally will be taxed at the preferential tax rates applicable to long-term capital gains if (a) the Company is a "qualified foreign corporation" (as defined below), (b) the U.S. Holder receiving such dividend is an individual, estate, or trust, and (c) such dividend is paid on Common Shares that have been held by such U.S. Holder for at least 61 days during the 121-day period beginning 60 days before the "ex-dividend date."

The Company generally will be a "qualified foreign corporation" under Section 1(h)(11) of the Code (a "QFC") if (a) the Company is eligible for the benefits of the Canada-U.S. Tax Convention, or (b) the Common Shares are readily tradable on an established securities market in the U.S. However, even if the Company satisfies one or more of such requirements, the Company will not be treated as a QFC if the Company is a "passive foreign investment company" (as defined below) for the taxable year during which the Company pays a dividend or for the preceding taxable year.

As discussed below, the Company does not believe that it was a "passive foreign investment company" for the taxable year ended 2006, and does not expect that it will be a "passive foreign investment company" for the taxable year ending 2007. (See more detailed discussion at "Additional Rules that May Apply to U.S. Holders" below). However, there can be no assurance that the IRS will not challenge the determination made by the Company concerning its "passive foreign investment company" status or that the Company will not be a "passive foreign investment company" for the current taxable year or any subsequent taxable year. Accordingly, although the Company expects that it may be a QFC for the taxable year ending 2007, there can be no assurances that the IRS will not challenge the determination made by the Company concerning its QFC status, that the Company will be a QFC for the taxable year ending 2007 or any subsequent taxable year, or that the Company will be able to certify that it is a QFC in accordance with the certification procedures issued by the Treasury and the IRS.

If the Company is not a QFC, a dividend paid by the Company to a U.S. Holder, including a U.S. Holder that is an individual, estate, or trust, generally will be taxed at ordinary income tax rates (and not at the preferential tax rates applicable to long-term capital gains). The dividend rules are complex, and each U.S. Holder should consult its own tax advisor regarding the dividend rules.

Distributions Paid in Foreign Currency

The amount of a distribution received on the Common Shares in foreign currency generally will be equal to the U.S. dollar value of such distribution based on the exchange rate applicable on the date of receipt. A U.S. Holder that does not convert foreign currency received as a distribution into U.S. dollars on the date of receipt generally will have a tax basis in such foreign currency equal to the U.S. dollar value of such foreign currency on the date of receipt. Such a U.S. Holder generally will recognize ordinary income or loss on the subsequent sale or other taxable disposition of such foreign currency (including an exchange for U.S. dollars).

Dividends Received Deduction

Dividends received on the Common Shares generally will not be eligible for the "dividends received deduction." The availability of the dividends received deduction is subject to complex limitations that are beyond the scope of this summary, and a U.S. Holder that is a corporation should consult its own tax advisor regarding the dividends received deduction.

Disposition of Common Shares

A U.S. Holder will recognize gain or loss on the sale or other taxable disposition of Common Shares in an amount equal to the difference, if any, between (a) the amount of cash plus the fair market value of any property received and (b) such U.S. Holder's tax basis in the Common Shares sold or otherwise disposed of. Subject to the "passive foreign investment company" rules discussed below, any such gain or loss generally will be capital gain or loss, which will be long-term capital gain or loss if the Common Shares are held for more than one year.

Preferential tax rates apply to long-term capital gains of a U.S. Holder that is an individual, estate, or trust. There are currently no preferential tax rates for long-term capital gains of a U.S. Holder that is a corporation. Deductions for capital losses are subject to significant limitations under the Code.

Foreign Tax Credit

A U.S. Holder that pays (whether directly or through withholding) Canadian income tax with respect to dividends received on the Common Shares generally will be entitled, at the election of such U.S. Holder, to receive either a deduction or a credit for such Canadian income tax paid. Generally, a credit will reduce a U.S. Holder's U.S. federal income tax liability on a dollar-for-dollar basis, whereas a deduction will reduce a U.S. Holder's income subject to U.S. federal income tax. This election is made on a year-by-year basis and applies to all foreign taxes paid (whether directly or through withholding) by a U.S. Holder during a taxable year.

Complex limitations apply to the foreign tax credit, including the general limitation that the credit cannot exceed the proportionate share of a U.S. Holder's U.S. federal income tax liability that such U.S. Holder's "foreign source" taxable income bears to such U.S. Holder's worldwide taxable income. In applying this limitation, a U.S. Holder's various items of income and deduction must be classified, under complex rules, as either "foreign source" or "U.S. source." In addition, this limitation is calculated separately with respect to specific categories of income (including "passive income," "high withholding tax interest," "financial services income," "general income," and certain other categories of income). Gain or loss recognized by a U.S. Holder on the sale or other taxable disposition of Common Shares generally will be treated as "U.S. source" for purposes of applying the foreign tax credit rules. Dividends received on the Common Shares generally will be treated as "foreign source" and generally will be categorized as "passive income" The foreign tax credit rules are complex, and each U.S. Holder should consult its own tax advisor regarding the foreign tax credit rules.

Information Reporting; Backup Withholding Tax

Payments made within the U.S., or by a U.S. payor or U.S. middleman, of dividends on, or proceeds arising from the sale or other taxable disposition of, Common Shares generally will be subject to information reporting and backup withholding tax, at the rate of 28%, if a U.S. Holder (a) fails to furnish such U.S. Holder's correct U.S. taxpayer identification number (generally on Form W-9), (b) furnishes an incorrect U.S. taxpayer identification number, (c) is notified by the IRS that such U.S. Holder has previously failed to properly report items subject to backup withholding tax, or (d) fails to certify, under penalty of perjury, that such U.S. Holder has furnished its correct U.S. taxpayer identification number and that the IRS has not notified such U.S. Holder that it is subject to backup withholding tax. However, U.S. Holders that are corporations generally are excluded from these information reporting and backup withholding tax rules. Any amounts withheld under the U.S. backup withholding tax rules will be allowed as a credit against a U.S. Holder's U.S. federal income tax liability, if any, or will be refunded, if such U.S. Holder furnishes required information to the IRS. Each U.S. Holder should consult its own tax advisor regarding the information reporting and backup withholding tax rules.

Additional Rules that May Apply to U.S. Holders

If the Company is a "controlled foreign corporation" or a "passive foreign investment company" (each as defined below), the preceding sections of this summary may not describe the U.S. federal income tax consequences to a U.S. Holder of the acquisition, ownership, and disposition of Common Shares.

Controlled Foreign Corporation

The Company generally will be a "controlled foreign corporation" under Section 957(a) of the Code (a "CFC") if more than 50% of the total voting power or the total value of the outstanding shares of the Company is owned, directly or indirectly, by citizens or residents of the U.S., domestic partnerships, domestic corporations, domestic estates, or domestic trusts (each as defined in Section 7701(a)(30) of the Code), each of which own, directly or indirectly, 10% or more of the total voting power of the outstanding shares of the Company (a "10% Shareholder").

If the Company is a CFC, a 10% Shareholder generally will be subject to current U.S. federal income tax with respect to (a) such 10% Shareholder's pro rata share of the "subpart F income" (as defined in Section 952 of the

Code) of the Company and (b) such 10% Shareholder's pro rata share of the earnings of the Company invested in "United States property" (as defined in Section 956 of the Code). In addition, under Section 1248 of the Code, any gain recognized on the sale or other taxable disposition of Common Shares by a U.S. Holder that was a 10% Shareholder at any time during the five-year period ending with such sale or other taxable disposition generally will be treated as a dividend to the extent of the "earnings and profits" of the Company that are attributable to such Common Shares. If the Company is both a CFC and a "passive foreign investment company" (as defined below), the Company generally will be treated as a CFC (and not as a "passive foreign investment company") with respect to any 10% Shareholder.

The Company does not believe that it has previously been, or currently is, a CFC. However, there can be no assurance that the Company will not be a CFC for the current or any subsequent taxable year.

Passive Foreign Investment Company

The Company generally will be a "passive foreign investment company" under Section 1297(a) of the Code (a "PFIC") if, for a taxable year, (a) 75% or more of the gross income of the Company for such taxable year is passive income or (b) on average, 50% or more of the assets held by the Company either produce passive income or are held for the production of passive income, based on the fair market value of such assets (or on the adjusted tax basis of such assets, if the Company is not publicly traded and either is a "controlled foreign corporation" or makes an election). "Passive income" includes, for example, dividends, interest, certain rents and royalties, certain gains from the sale of stock and securities, and certain gains from commodities transactions. However, for transactions entered into after December 31, 2004, active business gains arising from the sale or exchange of commodities by the Company generally are excluded from "passive income" if substantially all of the Company's commodities are (a) stock in trade of the Company or other property of a kind that would properly be included in inventory of the Company, or property held by the Company primarily for sale to customers in the ordinary course of business, (b) property used in the trade or business of the Company that would be subject to the allowance for depreciation under section 167 of the Code, or (c) supplies of a type regularly used or consumed by the Company in the ordinary course of its trade or business.

For purposes of the PFIC income test and asset test described above, if the Company owns, directly or indirectly, 25% or more of the total value of the outstanding shares of another corporation, the Company will be treated as if it (a) held a proportionate share of the assets of such other corporation and (b) received directly a proportionate share of the income of such other corporation. In addition, for purposes of the PFIC income test and asset test described above, "passive income" does not include any interest, dividends, rents, or royalties that are received or accrued by the Company from a "related person" (as defined in Section 954(d)(3) of the Code), to the extent such items are properly allocable to the income of such related person that is not passive income.

In addition, if the company is a PFIC and owns shares of another foreign corporation that also is a PFIC, under certain indirect ownership rules, a disposition of the shares of such other foreign corporation or a distribution received from such other foreign corporation generally will be treated as an indirect disposition by a U.S. Holder or an indirect distribution received by a U.S. holder, subject to the rules of Section 1291 of the Code discussed below. To the extent that gain recognized on the actual disposition by a U.S. Holder of the company's common stock or income recognized by a U.S. Holder on an actual distribution received on the company's common stock was previously subject to U.S. federal income tax under these indirect ownership rules, such amount generally should not be subject to U.S. federal income tax.

Based on the current composure of the assets and income of the Company, the Company does not believe that it was a PFIC for the taxable year ended 2006, and does not expect that it will be a PFIC for the taxable year ending 2007. The determination of whether the Company was, or will be, a PFIC for a taxable year depends, in part, on the application of complex U.S. federal income tax rules, which are subject to differing interpretations. In addition, whether the Company will be a PFIC for the taxable year ending 2007 and each subsequent taxable year depends on the assets and income of the Company over the course of each such taxable year and, as a result, cannot be predicted with certainty as of the date of this Annual Report. Accordingly, there can be no assurance that the IRS will not challenge the determination made by the Company concerning its PFIC status or that the Company was not, or will not be, a PFIC for any taxable year.

Default PFIC Rules Under Section 1291 of the Code

If the Company is a PFIC, the U.S. federal income tax consequences to a U.S. Holder of the acquisition, ownership, and disposition of Common Shares will depend on whether such U.S. Holder makes an election to treat the Company as a "qualified electing fund" or "QEF" under Section 1295 of the Code (a "QEF Election") or a mark-to-market election under Section 1296 of the Code (a "Mark-to-Market Election"). A U.S. Holder that does not make either a QEF Election or a Mark-to-Market Election will be referred to in this summary as a "Non-Electing U.S. Holder."

A Non-Electing U.S. Holder will be subject to the rules of Section 1291 of the Code with respect to (a) any gain recognized on the sale or other taxable disposition of Common Shares and (b) any excess distribution received on the Common Shares. A distribution generally will be an "excess distribution" to the extent that such distribution (together with all other distributions received in the current taxable year) exceeds 125% of the average distributions received during the three preceding taxable years (or during a U.S. Holder's holding period for the Common Shares, if shorter).

Under Section 1291 of the Code, any gain recognized on the sale or other taxable disposition of Common Shares, and any excess distribution received on the Common Shares, must be ratably allocated to each day in a Non-Electing U.S. Holder's holding period for the Common Shares. The amount of any such gain or excess distribution allocated to prior years of such Non-Electing U.S. Holder's holding period for the Common Shares (other than years prior to the first taxable year of the Company beginning after December 31, 1986 for which the Company was not a PFIC) will be subject to U.S. federal income tax at the highest tax rate applicable to ordinary income in each such prior year. A Non-Electing U.S. Holder will be required to pay interest on the resulting tax liability for each such prior year, calculated as if such tax liability had been due in each such prior year. Such a Non-Electing U.S. Holder that is not a corporation must treat any such interest paid as "personal interest," which is not deductible. The amount of any such gain or excess distribution allocated to the current year of such Non-Electing U.S. Holder's holding period for the Common Shares will be treated as ordinary income in the current year, and no interest charge will be incurred with respect to the resulting tax liability for the current year.

If the Company is a PFIC for any taxable year during which a Non-Electing U.S. Holder holds Common Shares, the Company will continue to be treated as a PFIC with respect to such Non-Electing U.S. Holder, regardless of whether the Company ceases to be a PFIC in one or more subsequent taxable years. A Non-Electing U.S. Holder may terminate this deemed PFIC status by electing to recognize gain (which will be taxed under the rules of Section 1291 of the Code discussed above) as if such Common Shares were sold on the last day of the last taxable year for which the Company was a PFIC.

QEF Election

The procedure for making a QEF Election, and the U.S. federal income tax consequences of making a QEF Election, will depend on whether such QEF Election is timely. A QEF Election generally will be "timely" if it is made for the first year in a U.S. Holder's holding period for the Common Shares in which the Company is a PFIC. In this case, a U.S. Holder may make a timely QEF Election by filing the appropriate QEF Election documents with such U.S. Holder's U.S. federal income tax return for such first year. However, if the Company was a PFIC in a prior year in a U.S. Holder's holding period for the Common Shares, then in order to be treated as making a "timely" QEF Election, such U.S. Holder must elect to recognize gain (which will be taxed under the rules of Section 1291 of the Code discussed above) as if the Common Shares were sold on the qualification date for an amount equal to the fair market value of the Common Shares on the qualification date. The "qualification date" is the first day of the first taxable year in which the Company was a QEF with respect to such U.S. Holder. In addition, under very limited circumstances, a U.S. Holder may make a retroactive QEF Election if such U.S. Holder failed to file the QEF Election documents in a timely manner.

A QEF Election will apply to the taxable year for which such QEF Election is made and to all subsequent taxable years, unless such QEF Election is invalidated or terminated or the IRS consents to revocation of such QEF Election. If a U.S. Holder makes a QEF Election and, in a subsequent taxable year, the Company ceases to be a PFIC, the QEF Election will remain in effect (although it will not be applicable) during those taxable years in which the Company is not a PFIC. Accordingly, if the Company becomes a PFIC in another subsequent taxable year, the QEF Election will be effective and the U.S. Holder will be subject to the QEF rules described above during any such subsequent taxable year in which the Company qualifies as a PFIC. In addition, the QEF Election will remain in effect (although it will not be applicable) with respect to a U.S. Holder even after such U.S. Holder disposes of all of such U.S. Holder's direct and indirect interest in the Common Shares. Accordingly, if such U.S. Holder reacquires an interest in the Company, such U.S. Holder will be subject to the QEF rules described above for each taxable year in which the Company is a PFIC.

A U.S. Holder that makes a timely QEF Election generally will not be subject to the rules of Section 1291 of the Code discussed above. For example, a U.S. Holder that makes a timely QEF Election generally will recognize capital gain or loss on the sale or other taxable disposition of Common Shares.

However, for each taxable year in which the Company is a PFIC, a U.S. Holder that makes a QEF Election will be subject to U.S. federal income tax on such U.S. Holder's pro rata share of (a) the net capital gain of the Company, which will be taxed as long-term capital gain to such U.S. Holder, and (b) and the ordinary earnings of the Company, which will be taxed as ordinary income to such U.S. Holder. Generally, "net capital gain" is the excess of (a) net long-term capital gain over (b) net short-term capital loss, and "ordinary earnings" are the excess of (a) "earnings and profits" over (b) net capital gain. A U.S. Holder that makes a QEF Election will be subject to U.S. federal income tax on such amounts for each taxable year in which the Company is a PFIC, regardless of whether such amounts are actually distributed to such U.S. Holder by the Company. However, a U.S. Holder that makes a QEF Election may, subject to certain limitations, elect to defer payment of current U.S. federal income tax on such amounts, subject to an interest charge. If such U.S. Holder is not a corporation, any such interest paid will be treated as "personal interest," which is not deductible.

A U.S. Holder that makes a QEF Election generally (a) may receive a tax-free distribution from the Company to the extent that such distribution represents "earnings and profits" of the Company that were previously included in income by the U.S. Holder because of such QEF Election and (b) will adjust such U.S. Holder's tax basis in the Common Shares to reflect the amount included in income or allowed as a tax-free distribution because of such QEF Election.

Each U.S. Holder should consult its own tax advisor regarding the availability of, and procedure for making, a QEF Election. U.S. Holders should be aware that there can be no assurance that the Company will satisfy record keeping requirements that apply to a QEF, or that the Company will supply U.S. Holders with information that such U.S. Holders require to report under the QEF rules, in the event that the Company is a PFIC and a U.S. Holder wishes to make a QEF Election.

Mark-to-Market Election

A U.S. Holder may make a Mark-to-Market Election only if the Common Shares are marketable stock. The Common Shares generally will be "marketable stock" if the Common Shares are regularly traded on a qualified exchange or other market. For this purpose, a "qualified exchange or other market" includes (a) a national securities exchange that is registered with the Securities and Exchange Commission, (b) the national market system established pursuant to section 11A of the Securities and Exchange Act of 1934, or (c) a foreign securities exchange that is regulated or supervised by a governmental authority of the country in which the market is located, provided that (i) such foreign exchange has trading volume, listing, financial disclosure, surveillance, and other requirements designed to prevent fraudulent and manipulative acts and practices, remove impediments to and perfect the mechanism of a free, open, fair, and orderly market, and protect investors (and the laws of the country in which the foreign exchange is located and the rules of the foreign exchange ensure that such requirements are actually enforced) and (ii) the rules of such foreign exchange effectively promote active trading of listed stocks. If the Common Shares are traded on such a qualified exchange or other market, the Common Shares generally will be "regularly traded" for any calendar year during which the Common Shares are traded, other than in de minimis quantities, on at least 15 days during each calendar quarter.

A Mark-to-Market Election applies to the taxable year in which such Mark-to-Market Election is made and to each subsequent taxable year, unless the Common Shares cease to be "marketable stock" or the IRS consents to revocation of such election. Each U.S. Holder should consult its own tax advisor regarding the availability of, and procedure for making, a Mark-to-Market Election.

A U.S. Holder that makes a Mark-to-Market Election generally will not be subject to the rules of Section 1291 of the Code discussed above. However, if a U.S. Holder makes a Mark-to-Market Election after the beginning of such U.S. Holder's holding period for the Common Shares and such U.S. Holder has not made a timely QEF Election, the rules of Section 1291 of the Code discussed above will apply to certain dispositions of, and distributions on, the Common Shares.

A U.S. Holder that makes a Mark-to-Market Election will include in ordinary income, for each taxable year in which the Company is a PFIC, an amount equal to the excess, if any, of (a) the fair market value of the Common Shares as of the close of such taxable year over (b) such U.S. Holder's adjusted tax basis in such Common Shares. A U.S. Holder that makes a Mark-to-Market Election will be allowed a deduction in an amount equal to the lesser of (a) the excess, if any, of (i) such U.S. Holder's adjusted tax basis in the Common Shares over (ii) the fair market value of such Common Shares as of the close of such taxable year or (b) the excess, if any, of (i) the amount included in ordinary income because of such Mark-to-Market Election for prior taxable years over (ii) the amount allowed as a deduction because of such Mark-to-Market Election for prior taxable years.

A U.S. Holder that makes a Mark-to-Market Election generally will adjust such U.S. Holder's tax basis in the Common Shares to reflect the amount included in gross income or allowed as a deduction because of such Mark-to-Market Election. In addition, upon a sale or other taxable disposition of Common Shares, a U.S. Holder that makes a Mark-to-Market Election will recognize ordinary income or loss (not to exceed the excess, if any, of (a) the amount included in ordinary income because of such Mark-to-Market Election for prior taxable years over (b) the amount allowed as a deduction because of such Mark-to-Market Election for prior taxable years).

Other PFIC Rules

Under Section 1291(f) of the Code, the IRS has issued proposed Treasury Regulations that, subject to certain exceptions, would cause a U.S. Holder that had not made a timely QEF Election to recognize gain (but not loss) upon certain transfers of Common Shares that would otherwise be tax-deferred (such as gifts and exchanges pursuant to tax-deferred reorganizations under Section 368 of the Code). However, the specific U.S. federal income tax consequences to a U.S. Holder may vary based on the manner in which Common Shares are transferred.

Certain additional adverse rules will apply with respect to a U.S. Holder if the Company is a PFIC, regardless of whether such U.S. Holder makes a QEF Election. For example under Section 1298(b)(6) of the Code, a U.S. Holder that uses Common Shares as security for a loan will, except as may be provided in Treasury Regulations, be treated as having made a taxable disposition of such Common Shares.

The PFIC rules are complex, and each U.S. Holder should consult its own tax advisor regarding the PFIC rules and how the PFIC rules may affect the U.S. federal income tax consequences of the acquisition, ownership, and disposition of Common Shares.

Canadian Federal Income Tax Considerations

The summary below is restricted to the case of a holder (a "Holder") of one or more Common shares who for the purposes of the Income Tax Act (Canada) (the "Act") is a non-resident of Canada, holds his Common shares as capital property and deals at arm's length with the Company.

Dividends

A Holder will be subject to Canadian withholding tax ("Part XIII Tax") equal to 25%, or such lower rate as may be available under an applicable tax treaty, of the gross amount of any dividend paid or deemed to be paid on these Common shares. Under the 1995 Protocol amending the Canada-U.S. Income Tax Convention (1980) (the "Treaty") the rate of Part XIII Tax is applicable to a dividend on Common shares paid to a Holder who is a resident of the United States. The Company will be required to withhold the applicable amount of Part XIII Tax from each dividend so paid and remit the withheld amount directly to the Receiver General for Canada for the account of the Holder, which is 15% reduced to 5% if the shareholder owns at least 10% of the outstanding Common shares of the Company.

Disposition of Common Shares

A Holder who disposes of a Common share, including by deemed disposition on death, will not be subject to Canadian tax on any capital gain (or capital loss) thereby realized unless the Common share constituted "taxable Canadian property" as defined by the Act. A capital gain occurs when proceeds from the disposition of a share of other capital property exceeds the original cost. A capital loss occurs when the proceeds from the disposition of a share are less than the original cost. Under the Act, capital gain is effectively taxed at a lower rate as only 50% of the gain is effectively included in the Holder's taxable income.

Generally, a Common share will not constitute taxable Canadian property of a Holder unless he held the Common shares as capital property used by him carrying on a business (other than an insurance business) in Canada, or he or persons with whom he did not deal at arm's length alone or together held or held options to acquire, at any time within the five years preceding the disposition, 25% or more of the shares of any class of the capital stock of the Company. The disposition of a Common share that constitutes "taxable Canadian property" of a Holder could also result in a capital loss which can be used to reduce taxable income to the extent that such Holder can offset it against a capital gain. A capital loss cannot be used to reduce all taxable income (only that portion of taxable income derived from a capital gain).

A Holder who is a resident of the United States and realizes a capital gain on disposition of a Common share that was taxable Canadian property will nevertheless, by virtue of the Treaty, generally be exempt from Canadian tax thereon unless (a) more than 50% of the value of the Common share is derived from, or forms an interest in, Canadian real estate, including Canadian mineral resource properties, (b) the Common share formed part of the business property of a permanent establishment that the Holder has or had in Canada within the 12 months preceding disposition, or (c) the Holder (i) was a resident of Canada at any time within the ten years immediately, and for a total of 120 months during the 20 years, preceding the disposition, and (ii) owned the Common share when he ceased to be resident in Canada.

A Holder who is subject to Canadian tax in respect of a capital gain realized on disposition of a Common share must include one-half of the capital gain (taxable capital gain) in computing his taxable income earned in Canada. This Holder may, subject to certain limitations, deduct one-half of any capital loss (allowable capital loss) arising on disposition of taxable Canadian property from taxable capital gains realized in the year of disposition in respect to taxable Canadian property and, to the extent not so deductible, from such taxable capital gains of any of the three preceding years or any subsequent year.

Recent Sales of Unregistered Securities

In February 2004, we raised gross proceeds of $2,972,061 in a private placement of 11,428,572 units of equity securities. Each unit consisted of one common share and one-half non-transferable share purchase warrant. One whole warrant entitled the holder to purchase one share of our common stock at a price of Cdn$0.50 per share on or before twelve months from closing. We offered and sold the units outside the United States to non-U.S. persons in off-shore transactions pursuant to the exemption from registration available under Regulation S of the Securities Act. We paid Jennings Capital, Inc,. the placement agent, a cash commission of 8% of the subscription proceeds ($228,622) and issued to the placement agent warrants equal to 8% of the number of units sold to purchase one share of our common stock at a price of Cdn$0.50 per share on or before twelve months from closing. In August 2004, we received net proceeds of $2,174,810 from the early exercise of 5,649,286 of the 5,714,286 purchase warrants issued to investors in the private placement. As an incentive to the warrant holders to exercise six months early, we issued an additional one-half non-transferable share purchase warrant, or a total of 2,824,643 bonus warrants, for each common share purchase warrant exercised. Each bonus warrant entitled the holder to purchase one share of our common stock at a price of Cdn$1.00 per share on or before twelve months from closing. In August 2005, we received $2,137,223 from the exercise of 2,561,618 bonus warrants.

In March 2005, we raised gross proceeds of $7,151,768 in a non-brokered private placement of 10 million common shares. We used the net proceeds of this transaction to fund our exploration and development program. We offered and sold shares outside the United States to non-U.S. persons in off-shore transactions pursuant to the exemption from registration available under Regulation S of the Securities Act and in the United States in private transactions not involving a public offering pursuant to exemptions available under Rule 506 of Regulation D and

Section 4(2) of the Securities Act. Expenses incurred totaled $292,370. Jennings Capital, Inc. acted as the placement agent.

In December 2005, we raised gross and net proceeds of $8,492,475 in an non-brokered private placement of 7 million common shares. We offered and sold shares outside the United States to non-U.S. persons in off-shore transactions pursuant to the exemption from registration available under Regulation S of the Securities Act and in the United States in private transactions not involving a public offering pursuant to exemptions available under Rule 506 of Regulation D and Section 4(2) of the Securities Act.

In March 2006, we raised $36,537,239 in a private placement of 19,514,268 common shares to accredited investors. We offered and sold shares outside the United States to non-U.S. persons in off-shore transactions pursuant to the exemption from registration available under Regulation S of the Securities Act and in the United States in private transactions not involving a public offering pursuant to exemptions available under Rule 506 of Regulation D and Section 4(2) of the Securities Act. Expenses incurred totaled $2,907,199. KeyBanc and Dominick & Dominick acted as placement agents.

Sale of Registered Securities

In December 2006, we raised net proceeds of $46,672,212 in a public offering of 12,075,000 shares of common stock, all of which shares were sold. The registration statements to register the shares became effective on December 15, 2006 (commission file number 333-138932) and December 18, 2006 (commission file number 333-139441). The offering commenced on December 21, 2006. The aggregate price of the offering amount registered and sold totaled $50,111,250. Expenses incurred from the effective date of the registration statements to the ending date of the reporting period totaled $3,439,038. KeyBanc Capital Markets was the lead manager of the offering, with A.G. Edwards and Petrie Parkman & Co. acting as co-managers. We expect to use the net proceeds to fund a portion of our 2007 exploration and drilling programs and for working capital and general corporate purposes.

Issuer Purchases of Equity Securities

During the fourth quarter of the fiscal year ended December 31, 2006, the Company did not purchase any of its equity securities.

ITEM 6. SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following tables set forth selected consolidated financial data as of and for the years ended December 31, 2006, 2005, and 2004. The data as of and for the fiscal years ended December 31, 2006, 2005, and 2004 was derived from our audited annual consolidated financial statements included elsewhere in this Form 10-K.

You should read the following selected consolidated financial data together with our historical consolidated financial statements, including the related notes, and "Management's Discussion and Analysis of Financial Conditions and Results of Operations" included elsewhere in this Form 10-K.

	Year Ended December 31		
	2006	2005	2004
Income Statement Data:			
Revenues	$ 4,965,169	$ 453,135	$ 20,449
Costs and Expenses	7,751,209	2,458,226	1,082,549
Net Income (Loss)	(2,786,040)	(2,005,091)	(1,062,100)
Net Income (Loss) per Share	$ (0.04)	$ (0.05)	$ (0.04)
Other Financial Data:			
Adjusted EBITDA(1)	$ 947,247	$ (1,210,248)	$ (705,765)

(1) We define Adjusted EBITDA as net income before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion and amortization, (iv) non-cash expenses relating to share based payments under FAS 123R, (v) pre-tax unrealized gains and losses on foreign currency and (vi) accretion of abandonment liability. We

present Adjusted EBITDA because we consider it an important supplemental measure of our performance, in particular because it excludes amounts, such as expenses relating to share-based payments and unrealized gains and losses on foreign currency, that do not relate directly to our operating performance. This term, as we define it, may not be comparable to similarly titled measures employed by other companies and is not a measure of liquidity calculated in accordance with accounting principles generally accepted in the United States, or GAAP. Adjusted EBITDA should not be considered in isolation or as a substitute for operating income, net income, cash flows provided by operating activities or other income or cash flow statement data prepared in accordance with GAAP. See "Non GAAP Financial Measure."

	As at December 31		
	2006	**2005**	**2004**
Balance Sheet Data:			
Current Assets	$ 61,117,145	$ 7,990,566	$ 2,756,745
Property and Equipment	52,250,265	17,463,269	2,357,601
Total Assets	113,773,614	25,790,316	5,207,486
Current Liabilities	9,879,104	4,411,572	369,008
Long-term Debt	-0-	-0-	-0-
Shareholder's Equity	$ 103,644,815	$ 21,309,671	$ 4,838,478
Weighted Average Number of Shares Outstanding	71,425,243	44,447,269	27,696,443

No dividends have been declared in any of the periods presented above.

Non-GAAP Financial Measure

We use EBITDA, adjusted as described below, referred to in this Form 10-K as Adjusted EBITDA, as a supplemental measure or our performance that is not required by, or presented in accordance with, GAAP. We define Adjusted EBITDA as net income before (i) interest expense, (ii) income taxes, (iii) depreciation , depletion and amortization, (iv) non-cash expenses relating to share based payments under FAS 123R, (v) pre-tax unrealized gains and losses on foreign currency and (vi) accretion of abandonment liability. We present Adjusted EBITDA because we consider it an important supplemental measure of our performance, in particular because it excludes amounts, such as expenses relating to share-based payments and unrealized gains and losses on foreign currency, that do not relate directly to our operating performance. Because the use of Adjusted EBITDA facilitates comparisons of our historical operating performance on a more consistent basis, we use this measure for business planning and analysis purposes and in assessing acquisition opportunities and overall rates of return.

Adjusted EBITDA is not a measurement of our financial performance under GAAP and should not be considered as an alternative to net income, operating income or any other performance measure derived in accordance with GAAP, as an alternative to cash flow from operating activities or as a measure of our liquidity. You should not assume that the Adjusted EBITDA amounts shown in this Form 10-K are comparable to Adjusted EBITDA amounts disclosed by other companies. In evaluating Adjusted EBITDA, you should be aware that it excludes expenses that we will incur in the future on a recurring basis.

Adjusted EBITDA has limitations as an analytical tool, and you should not consider it in isolation. Some of its limitations are:

- it does not reflect non-cash costs of our stock incentive plans, which are an ongoing component of our employee compensation program; and
- although depletion, depreciation and amortization are non-cash charges, the assets being depleted, depreciated and amortized will often have to be replaced in the future, and Adjusted EBITDA does not reflect the cost or cash requirements for such replacements.

We compensate for these limitations by relying primarily on our GAAP results and using Adjusted EBITDA only supplementally. The following table presents a reconciliation of our net income to our Adjusted EBITDA on a historical basis for each of the periods indicated.

	Year Ended December 31,		
	2006	2005	2004
Net income / (Loss)	$ (2,786,040)	$ (2,005,091)	$ (1,062,100)
Add back:			
Depreciation, depletion & amortization & abandonment liability accretion expense	2,173,918	157,868	13,681
(Gain) Loss on foreign currency exchange	32,008	95,864	(68,574)
Stock-based compensation expense	1,527,361	541,111	411,238
Adjusted EBITDA	$ 947,247	$ (1,210,248)	$ (705,765)

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the "Selected Historical Financial Data" and our historical consolidated financial statements and the accompanying notes.

Overview

We are an independent energy company focused on the exploration, exploitation, acquisition and production of natural gas and crude oil in the United States. Our oil and natural gas reserves and operations are concentrated in two Rocky Mountain basins. Our corporate strategy is to internally identify prospects, acquire lands encompassing those prospects and evaluate those prospects using subsurface geology and geophysical data and exploratory drilling. Using this strategy, we have developed an oil and natural gas portfolio of proved reserves, as well as conventional and unconventional prospects that we have the opportunity to explore, drill and develop.

As of December 31, 2006, we had estimated proved reserves of 5.6 Billion Cubic Feet Equivalent with a PV-10 value of $19.7 million. Our reserves are 93% proved developed and are comprised of 43% natural gas and 57% crude oil. Our December 31, 2006 reserves reflect a downward revision of the December 31, 2005 reserves of 2.8 BCF, primarily from the revision of reserves associated with our decision to discontinue exploration and development of our coalbed methane properties. We had discoveries and extensions during 2006 of 3.0 BCF and production of .489 BCF. The sharp drop in commodity prices used to determine reserves, especially the decline in natural gas prices year-over-year, resulted in the reduction in PUD locations given to the Company by its independent reservoir engineering firm, Netherland Sewell & Associates, Inc. (NSAI).

Our results of operations and financial condition are significantly affected by oil and natural gas commodity prices, which can fluctuate dramatically. The commodity prices are beyond our company's control and are difficult to predict. During 2006 and into the first two months of 2007 we have seen volatility in oil and natural gas prices. We believe that spot market prices reflect worldwide concerns about producers' ability to ensure sufficient supply to meet increasing demand amid a host of uncertainties caused by political instability, a weak U.S. dollar and crude oil refining constraint. During the past several months, commodity prices have declined. Prices on the New York Mercantile Exchange, or NYMEX, for 2006 are stated in the chart below for both oil and natural gas. We receive lower prices for our oil and natural gas than what is posted on the NYMEX as a result of the location of our reserves, transportation costs and adjustments for the gravity or density of the crude oil we produce and other factors. The chart below shows the price differentials received for our products for each of the periods.

2006	NYMEX West Texas Intermediate	Deducts*	Net Oil Price	NYMEX Natural Gas Settlement	Deducts*	Net Gas Price
January	$65.49	$(6.90)	$58.59	$11.43	$(2.63)	$8.80
February	$61.63	$(11.30)	$50.33	$8.40	$(1.71)	$6.69

2006	NYMEX West Texas Intermediate	Deducts*	Net Oil Price	NYMEX Natural Gas Settlement	Deducts*	Net Gas Price
March	$62.69	$(13.30)	$49.39	$6.64	$(0.56)	$6.08
April	$69.44	$(12.30)	$57.14	$7.23	$(1.66)	$5.57
May	$70.84	$(10.00)	$60.84	$7.20	$(1.49)	$5.71
June	$70.95	$(7.30)	$63.65	$5.93	$(1.14)	$4.79
July	$74.41	$(6.35)	$68.06	$5.80	$(0.82)	$4.98
August	$73.04	$(7.85)	$65.19	$7.04	$(1.24)	$5.80
September	$63.80	$(8.20)	$55.60	$6.38	$(1.28)	$5.10
October	$59.14	$(8.45)	$50.69	$4.20	$(1.55)	$2.65
November	$56.98	$(9.35)	$47.63	$7.15	$(1.10)	$6.05
December	$61.08	$(8.85)	$52.23	$8.32	$(2.62)	$5.70

* Deducts include locale differentials, transportation, and gravity adjustments

Outlook

We believe that oil and gas prices will remain volatile during 2007. As a result of increases in the prices of domestic oil and natural gas over the past several years, and the corresponding increased demand for oil field services, shortages have developed, and we have seen an escalation in rig rates, field service costs, material prices and all costs associated with drilling, completing and operating wells. If oil and natural gas prices remain high relative to historical levels, we anticipate that the recent trends toward increasing costs and equipment and personnel shortages will continue. While we have identified prospects to drill, our ability to grow could be adversely affected by these shortages and price increases.

We plan to make capital expenditures of approximately $60 million for 2007, which is a 65% increase over our 2006 capital expenditures of $37 million. We continuously evaluate our capital expenditures budget and make adjustments from time to time as our results of operations and other factors dictate. Our preliminary 2007 capital expenditures budget is approximately $60 million. The following table sets forth our planned capital expenditures for our principal properties in 2007:

Prospect Location	WI	Gross Wells	Net Wells	Estimated 2007 Expenditures
Green River Basin				
Vermillion Deep Operated	100.0%	7	7.00	$ 31,500,000
Vermillion Deep Non-Op	25.0%	2	0.50	2,250,000
Other Projects	50.0%	2	1.00	2,500,000
Acreage/Seismic				5,000,000
Total Green River Basin		**11**	**8.50**	**$ 41,250,000**
Williston Basin				
Mission Canyon / Red River	50.0%	6	3.00	$ 6,000,000
Bakken	62.5%	3	1.88	9,750,000
Acreage/Seismic				3,000,000
Total Williston Basin		**9**	**4.88**	**18,750,000**
Total Kodiak Oil & Gas		**20**	**13.38**	**$ 60,000,000**

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with generally accepted accounting principals in the United States, or GAAP, requires our management to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements and the reported amounts of revenues and expenses during the reporting period. The following is a summary of the significant accounting policies and related estimates that affect our financial disclosures.

Oil and Natural Gas Reserves

We believe estimated reserve quantities and the related estimates of future net cash flows are the most important estimates made by an exploration and production company such as ours because they affect the perceived value of our company, are used in comparative financial analysis ratios, and are used as the basis for the most significant accounting estimates in our financial statements, including the periodic calculation of depletion, depreciation and impairment of our proved oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. We determine anticipated future cash inflows and future production and development costs by applying benchmark prices and costs, including transportation, quality and basis differentials, in effect at the end of each period to the estimated quantities of oil and natural gas remaining to be produced as of the end of that period. We reduce expected cash flows to present value using a discount rate that depends upon the purpose for which the reserve estimates will be used. For example, the standardized measure calculation required by Statement of Financial Accounting Standards ("SFAS") No. 69, Disclosures about Oil and Gas Producing Activities, requires us to apply a 10% discount rate. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established proved producing oil and natural gas properties, we make considerable effort to estimate our reserves, including through the use of independent reserves engineering consultants. We expect that periodic reserve estimates will change in the future as additional information becomes available or as oil and natural gas prices and operating and capital costs change. We evaluate and estimate our oil and natural gas reserves as of December 31 of each year and at other such times throughout the year that we deem appropriate. For purposes of depletion, depreciation, and impairment, we adjust reserve quantities at all interim periods for the estimated impact of acquisitions and dispositions. Changes in depletion, depreciation or impairment calculations caused by changes in reserve quantities or net cash flows are recorded in the period in which the reserves or net cash flow estimate changes.

Impairment of Long-lived Assets

We record our property and equipment at cost. The cost of our unproved properties is withheld from the depletion base as described above, until such a time as the properties are either developed or abandoned. We review these properties periodically for possible impairment. We provide an impairment allowance on unproved property when we determine that the property will not be developed or the carrying value will not be realized. We evaluate the reliability of our proved properties and other long-lived assets whenever events or changes in circumstances indicate that the recording of impairment may be appropriate. Our impairment test compares the expected undiscounted future net revenue from a property, using escalated pricing, with the related net capitalized costs of the property at the end of the applicable period. When the net capitalized costs exceed the undiscounted future net revenue of a property, the cost of the property is added to the full cost pool.

Revenue Recognition

Our revenue recognition policy is significant because revenue is a key component of our results of operations and of the forward-looking statements contained in our analysis of liquidity and capital resources. We derive our revenue primarily from the sale of produced natural gas and crude oil. We report revenue as the gross amounts we receive before taking into account production taxes and transportation costs, which are reported as separate expenses. We record revenue in the month our production is delivered to the purchaser, but payment is generally received 30 to 90 days after the date of production. At the end of each month, we make estimates of the amount of production that we delivered to the purchaser and the price we will receive. We use our knowledge of our properties, their historical performance, the anticipated effect of weather conditions during the month of production, NYMEX and local spot market prices and other factors as the basis for these estimates. We record the variances between our estimates and the actual amounts we receive in the month payment is received.

Asset Retirement Obligations

We are required to recognize an estimated liability for future costs associated with the abandonment of our oil and gas properties including without limitation the costs of reclamation of our drilling sites, storage and transmission facilities and access roads. We base our estimate of the liability on the industry experience of our management and on our current understanding of federal and state regulatory requirements. Our present value calculations require us to estimate the economic lives of our properties, assume what future inflation rates apply to external estimates and determine the credit-adjusted risk-free rate to use. Our estimated asset retirement obligations are reflected in our depreciation, depletion and amortization calculations over the remaining life of our oil and gas properties.

Stock-Based Compensation

We account for stock-based compensation under the provisions of SFAS No. 123R, Accounting for Stock-Based Compensation. This statement requires us to record expense associated with the fair value of stock-based compensation. We currently use the Black-Scholes option valuation model to calculate stock based compensation.

Oil and Natural Gas Properties—Full Cost Method of Accounting

We use the full cost method of accounting whereby all costs related to the acquisition and development of oil and natural gas properties are capitalized into a single cost center referred to as a full cost pool. These costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling and overhead charges directly related to acquisition and exploration activities.

Capitalized costs, together with the costs of production equipment, are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves as determined by independent petroleum engineers. For this purpose, we convert our petroleum products and reserves to a common unit of measure.

Costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to the full cost pool and becomes subject to depletion calculations.

Proceeds from the sale of oil and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless the sale would alter the rate of depletion by more than 25%. Royalties paid, net of any tax credits, received are netted against oil and natural gas sales.

In applying the full cost method, we perform a ceiling test on properties that restricts the capitalized costs less accumulated depletion from exceeding an amount equal to the estimated undiscounted value of future net revenues from proved oil and natural gas reserves, as determined by independent petroleum engineers. The estimated future revenues are based on sales prices achievable under existing contracts and posted average reference prices in effect at the end of the applicable period, and current costs, and after deducting estimated future general and administrative expenses, production related expenses, financing costs, future site restoration costs and income taxes. Under the full cost method of accounting, capitalized oil and natural gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and natural gas reserves, plus the cost, or estimated fair value if lower, of unproved properties. Should capitalized costs exceed this ceiling, we would recognize an impairment.

Foreign Currency Fluctuations

Monetary items denominated in a foreign currency, other than U.S. dollars, are converted into U.S. dollars at exchange rates prevailing at the balance sheet date. Foreign currency denomination revenue and expense items are translated at exchange rates prevailing at the transaction date. Gains or losses arising from the translations are included in operations.

Operating Results

Fiscal Year Ended December 31, 2006 Compared to Fiscal Year Ended December 31, 2005

Natural Gas production revenues. Natural gas and natural liquid production revenues increased by $493,402 to $718,926 for the fiscal year ended December 31, 2006 from $225,524 for the same period of 2005. Increased natural gas production volumes more than offset price declines between the periods. Natural gas and natural gas liquid production volumes were 116,316 Mcf and 1,008 Mcf, respectively, for the fiscal year ended December 31, 2006 compared to 31,751 Mcf for the same period in 2005, whereas the average price we realized on the sale of our natural gas declined by 22% to $5.56 per Mcf for the fiscal year ended December 31, 2006 from $7.11 per Mcf for the same period of 2005. The increase in gas production volumes is due to an increase in the number of operating wells, from one well at December 31, 2005 to six at December 31, 2006. The average price we realized on the sale of our natural gas liquids was $10.24 per gallon for the fiscal year ended December 31, 2006. We did not have any natural gas liquid sales in 2005.

Oil production revenues. Oil production revenues increased by $3,300,126 to $3,440,182 for the fiscal year ended December 31, 2006 from $140,056 for the same period of 2005. Oil production volumes and realized oil prices increased during the period. Oil production volumes were 61,966 barrels for the fiscal year ended December 31, 2006 compared to 2,699 barrels for the same period in 2005, whereas the average price we realized on the sale of our oil increased by 7% to $55.52 per barrel for the fiscal year ended December 31, 2006 from $51.89 for the same period in 2005. The increase in oil production volumes is due to an increase in the number of operating wells, from one well at December 31, 2005 to seven at December 31, 2006.

Interest Income. Interest income increased by $718,506 to $806,061 in 2006 for the fiscal year ended December 31, 2006 from $87,555 for the same period in 2005. The increase was due to the investment of funds received from our March and December 2006 sale of shares of our common stock.

Oil and gas production expense. Our oil and gas production expense increased by $762,800 to $964,685 for the fiscal year ended December 31, 2006 from $201,885 for the same period in 2005. The increase is partially due to paying severance taxes on production from exploratory wells in Montana during the last part of 2006, whereas these same wells were exempt from state severance taxes in 2005. The increase also reflects our growing production base and number of producing wells.

Depletion, depreciation, amortization and abandonment liability accretion expense. Our depletion, depreciation, amortization and abandonment liability accretion expense increased by $2,016,050 to $2,173,918 for the fiscal year ended December 31, 2006 from $157,868 for the same period in 2005.The increase reflects our growing depletable and depreciable asset base and our production base.

General and administrative expense. General and administrative expense increased by $2,577,989 to $4,580,598 for the fiscal year ended December 31, 2006 from $2,002,609 for the same period in 2005. Included in the general and administrative expense for the fiscal year ended December 31, 2006 in accordance with SFAS No. 123R is a stock-based compensation charge of $1,527,361 for options issued to officers, directors and employees compared to $541,111 for the year ended December 31, 2005. The increase in general and administrative expenses for the fiscal year ended December 31, 2006 also reflects an increase in our level of activity and an increase in the number of employees and related salary and payroll expense. During the fiscal year ended December 31, 2006, we had twelve full-time employees and two part-time contract consultants, an increase of six from the same period in 2005. Salary and payroll expense increased by $728,912 to $1,677,220 for the fiscal year ended December 31, 2006 from $948,308 for the same period in 2005. During the fiscal year ended December 31, 2006 we paid bonuses totaling $707,000 to employees and management, compared to $111,500 during the same period in 2005. In 2006, we also incurred additional legal expenses and costs related to outside accounting services, as a result of our filings with the Securities and Exchange Commission, costs associated with our application for trading on the AMEX, and costs incurred in connection with our reporting to shareholders. We commenced trading on the AMEX on June 21, 2006.

Loss on currency exchange. Loss on currency exchange decreased by $63,856 to $32,008 for the fiscal year ended December 31, 2006 from $95,864 for the same period in 2005. We received a portion of the proceeds from our March 2006 private placement of common shares in Canadian dollars.

Net loss. Our net loss increased by $780,949 to a net loss of $2,786,040 for the fiscal year ended December 31, 2006 from a net loss of $2,005,091 for the same period of 2005. As more fully described above, the increases in our oil and natural gas production revenues, interest income and gain on currency exchange were more than offset by increases in oil and natural gas production expense, depletion, depreciation, amortization and abandonment liability expenses and general and administrative expenses.

Adjusted EBITDA. Our earnings before interest, taxes, depreciation, depletion, amortization and abandonment liability accretion increased by $2,157,495 to $947,247 for the fiscal year ended December 31, 2006 from $(1,210,248) for the same period of 2005. Adjusted EBITDA is not a GAAP measure. We use this non-GAAP measure primarily to compare our results with other companies in the industry that make a similar disclosure. We believe that this measure may also be useful to investors for the same purpose. Investors should not consider this measure in isolation or as a substitute for operating income, or any other measure for determining our operating performance that is calculated in accordance with GAAP. In addition, because Adjusted EBITDA is not a GAAP measure, it may not necessarily be comparable to similarly titled measures employed by other companies. A reconciliation between Adjusted EBITDA and net income is provided in the table below:

	Year Ended December 31,	
Reconciliation of Adjusted EBITDA:	**2006**	**2005**
Net Loss	$ (2,786,040)	$ (2,005,091)
Add back:		
Depreciation, depletion, amortization and abandonment liability accretion expense	2,173,918	157,868
Loss on foreign currency exchange	32,008	95,864
Stock based compensation expense	1,527,361	541,111
Adjusted EBITDA	$ 947,247	$ (1,210,248)

Fiscal Year Ended December 31, 2005 as Compared to Fiscal Year Ended December 31, 2004

Natural Gas production revenues. Natural gas production revenues were $225,524 for fiscal year 2005. Natural gas production volumes were 37,751 Mcf, and the average price we realized on the sale of our natural gas was $7.11 per Mcf for fiscal year 2005. The increase in natural gas production volumes reflected the commencement of production from our first operating natural gas well in 2005. We had no natural gas production revenues in fiscal year 2004.

Oil production revenues. Oil production revenues were $140,056 for fiscal year 2005. Oil production volumes were 2,699 barrels, and the average price we realized on the sale of our oil was $51.89 per barrel for fiscal year 2005. The increase in oil production volumes reflected commencement of production from our first operating oil well in 2005. We had no oil production revenues in fiscal year 2004.

Interest income. Interest income increased by $67,106 to $87,555 for fiscal year 2005 from $20,449 for fiscal year 2004. The increase in interest income primarily reflected higher average cash and, cash equivalent and short-term investment balances during fiscal year 2005, mainly as a result of proceeds from our financing activities.

Oil and natural gas production expense. Our oil and natural gas production expense was $201,885 for fiscal year 2005, which reflected the cost of placing wells on production. We had no wells on production in fiscal year 2004.

Depletion, depreciation, amortization and abandonment liability accretion expense. Our depletion, depreciation, amortization and abandonment liability accretion expense increased by $144,197 to $157,868 for fiscal year 2005 from $13,671 for fiscal year 2004. The increase reflects the increase in our production volume in 2005.

General and administrative expense. General and administrative expense increased by $865,157 to $2,002,609 for fiscal year 2005 from $1,137,452 for fiscal year 2004. The increase in general and administrative expense reflected additional salary and payroll expense and office overhead associated with our increased operations. During fiscal year 2005 we had eight employees, an increase of three from fiscal year 2004. The increase in expenses also reflected increased shareholder relations costs as we increased our exposure to the U.S. financial markets and a stock-based compensation charge of $541,111 for stock options issued to employees in fiscal year 2005.

Loss on currency exchange. Loss on currency exchange increased by $164,438 to $95,864 for fiscal year 2005 from a gain of $68,574 for fiscal year 2004. The strengthening of the Canadian dollar against the U.S. dollar resulted in the increased loss.

Net loss. Our net loss increased by $942,991 to a net loss of $2,005,091 for fiscal year 2005 from a net loss of $1,062,100 for fiscal year 2004. As more fully described above, the increases in our oil and natural gas production revenues, interest income and gain on currency exchange were more than offset by increases in oil and gas production expense, depletion, depreciation, amortization and abandonment liability expense and general and administrative expense.

Adjusted EBITDA. Our Adjusted EBITDA declined by $504,483 to $(1,210,248) for fiscal year 2005 from $(705,765) for fiscal year 2004. A reconciliation between Adjusted EBITDA and net income is provided in the table below:

	Year Ended December 31,	
Reconciliation of Adjusted EBITDA:	**2005**	**2004**
Net Loss	$ (2,005,091)	$ (1,062,100)
Add back:		
Depreciation, depletion, amortization and abandonment liability accretion expense	157,868	13,671
Loss on foreign currency exchange	95,864	(68,574)
Stock based compensation expense	541,111	411,238
Adjusted EBITDA	$ (1,210,248)	$ (705,765)

Liquidity and Capital Resources

We have financed our operations, property acquisitions and capital investments from the proceeds of private offerings of our equity securities and, more recently, from cash generated from operations. As of December 31, 2006, we had working capital of $53,238,041 and no long-term debt. During the fiscal year ended December 31, 2006, our additions to oil and natural gas properties were $37 million. Included in the expenditures were $7.6 million for the acquisition of mineral leaseholds in the Vermillion Basin.

We intend to operate two rigs in the Rocky Mountain region in 2007. We have entered into a rig contract with an independent third party for a drilling rig commencing in April 2007. We have a minimum obligation to drill at least five wells in the Vermillion Basin with the rig. We have built our first location and have begun moving the rig onto the location. We expect to commence drilling NT Federal #4-35 well the first week of April. The drilling rig that we have under contract in the Williston Basin is subject to a sixty-day notice to retain. We released the rig in early February 2007 for approximately sixty days. We expect to have the rig back under our control by early April 2007. Our future expenditures will be subject to drilling rig availability and the results of continued production.

We adopted a preliminary budget for capital expenditures in 2007 of $60 million. We believe that our existing cash and short term investments and cash flow from operations and borrowing from a credit facility that we intend to establish, will be sufficient to fund our anticipated 2007 exploration and development program and to meet our other cash requirements through 2007. We are currently in discussions with a lender to establish a credit facility.

Our ability to fund our operations in future periods will depend upon our future operating performance, and more broadly, on the availability of equity and debt financing, which will be affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control. We cannot be certain that additional funding will be available on acceptable terms, or at all. If we are unable to raise additional capital when required or on acceptable terms, we may have to significantly delay, scale back or discontinue our drilling or exploration program, seek to enter into a joint venture arrangement with a third party to fund our planned exploration and drilling programs, or seek to sell one or more of our properties.

Financial Instruments and Other Instruments

As at December 31, 2006, we had cash, accounts payable and accrued liabilities which are carried at approximate fair value because of the short maturity date of those instruments. Our management believes that we are not exposed to significant interest, currency or credit risks arising from these financial instruments.

Research and Development

As an exploration stage natural resource company, we do not normally engage in research and there were no development activities, and research and development expenditures made in the last three fiscal years.

Trend Information

Our industry has experienced a significant increase in the cost of drilling rigs and related oil field services. Drilling rigs have been difficult to contract and we cannot be assured that we can secure third party contracts. Commodity prices are at or near all time levels and we cannot be assured that they will continue at these levels. It is difficult to assure that we can retain qualified employees during a competitive period in the industry. Some or all of these situations are likely to have a material effect upon our net sales or revenues, income from continuing operations, profitability, liquidity or capital resources, or cause reported financial information not necessarily to be indicative of future operating results or financial condition.

Off-balance sheet arrangements

We have no off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Tabular disclosure of contractual obligations

The following table lists as of December 31, 2006 information with respect to our known contractual obligations.

	Payments due by Period				
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Long-Term Obligations—Office Facilities	$252,000	$66,600	$185,400	—	—

We have not included asset retirement obligations as discussed in note 2 of the accompanying audited financial statements, as we cannot determine with accuracy the timing of such payments.

In February 2007, the Company entered into a lease agreement for office facilities that expires June 2012. The commencement of this lease agreement will simultaneously terminate the existing lease commitment. See note 7 to the audited financial statements.

The following table shows the annual rentals per year for the life of the lease:

Contractual Obligations	Payments due by Period				
	Total	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Long-Term Obligations—Office Facilities	$1,152,200	$117,000	$426,900	$479,700	$128,600

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our primary market risk consists of market changes in oil and natural gas prices. Prospective revenues from the sale of products or properties will be impacted by oil and natural gas prices. A $1.00 per Mcf change in the market price of natural gas would result in a change of approximately $116,000 in our gross gas production revenue for the fiscal year ended December 31, 2006. A $1.00 per barrel change in the market price of oil would result in a change of approximately $62,000 in our gross oil production revenue for the fiscal year ended December 31, 2006. The impact on any potential sale of property cannot be readily determined.

Interest Rate Risk

We currently maintain some of our available cash in redeemable short-term investments, classified as cash equivalents, and our reported interest income from these short-term investments could be adversely affected by any material changes in U.S. dollar interest rates. A 1% change in the interest rate would result in a change of approximately $250,000 in our interest income for the fiscal year ended December 31, 2006 if all of our cash were invested in interest-bearing notes.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors
Kodiak Oil & Gas Corp.
Denver, Colorado

We have audited the consolidated balance sheet of Kodiak Oil & Gas Corp. and subsidiaries (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders' equity and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Kodiak Oil & Gas Corp. and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles.

***HEIN** & ASSOCIATES LLP*

Denver, Colorado
March 21, 2007

A PARTNERSHIP OF INCORPORATED
PROFESSIONALS

AMISANO HANSON

CHARTERED ACCOUNTANTS

AUDITORS' REPORT

To the Shareholders,
Kodiak Oil & Gas Corp.

We have audited the consolidated statements of operations and deficit and cash flows for the year ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance 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.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and the results of its operations and its cash flows for the year ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

Vancouver, Canada
April 12, 2005

"AMISANO HANSON"
Chartered Accountants

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KODIAK OIL & GAS CORP.
CONSOLIDATED BALANCE SHEETS

		December 31, 2006		December 31, 2005
ASSETS				
Current assets:				
Cash and cash equivalents	$	58,469,263	$	7,285,548
Accounts receivable				
Trade		1,877,185		447,981
Accrued Sales		666,990		226,406
Prepaid expenses and other		103,707		30,631
Total Current Assets		61,117,145		7,990,566
Property and equipment (full cost method), at cost:				
Proved oil and gas properties		27,167,338		8,816,220
Unproved oil and gas properties		19,607,474		6,307,903
Wells in progress		7,700,415		2,461,087
Less-accumulated depletion, depreciation and amortization		(2,224,962)		(121,941)
		52,250,265		17,463,269
Other property and equipment, net of accumulated depreciation of $102,231 in 2006 and $47,525 in 2005		181,752		183,481
Restricted Investments		224,452		153,000
Total Assets	$	113,773,614	$	25,790,316
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current Liabilities:				
Accounts payable and accrued liabilities	$	9,879,104	$	4,411,572
Noncurrent liabilities:				
Asset retirement obligation		249,695		69,073
Total Liabilities		10,128,799		4,480,645
Commitments and Contingencies – Note 7				
Stockholders' equity:				
Common stock, $0.01 par value: authorized-100,000,000				
Issued: 87,548,426 shares in 2006 and 54,547,158 in 2005		875,484		545,472
Additional paid in capital		111,384,998		26,593,826
Accumulated deficit		(8,615,667)		(5,829,627)
Total Stockholders' Equity		103,644,815		21,309,671
Total Liabilities and Stockholders' Equity	$	113,773,614	$	25,790,316

SEE ACCOMPANYING NOTES

KODIAK OIL & GAS CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31,		
	2006	**2005**	**2004**
Revenues:			
Gas production	$ 718,926	$ 225,524	$
Oil production	3,440,182	140,056	
Interest	806,061	87,555	20,449
Total revenue	4,965,169	453,135	20,449
Cost and expenses:			
Oil and gas production	964,685	201,885	
Depletion, depreciation, amortization and abandonment liability accretion	2,173,918	157,868	13,671
General and administrative	4,580,598	2,002,609	1,137,452
(Gain)/Loss on currency exchange	32,008	95,864	(68,574)
Total costs and expenses	7,751,209	2,458,226	1,082,549
Net loss for the period	$ (2,786,040)	$ (2,005,091)	$ (1,062,100)
Basic & diluted weighted-average common shares outstanding	71,425,243	44,447,269	27,696,443
Basic & diluted net loss per common share	$ (0.04)	$ (0.05)	$ (0.04)

SEE ACCOMPANYING NOTES

KODIAK OIL & GAS CORP.
STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock				Contributed		Accumulated		Total
	Shares		Amount		Surplus		Deficit		Equity
Balance December 31, 2003:	14,373,675		143,737		2,930,558		(2,762,436)		311,859
Issuance of stocks for cash:									
-pursuant to private placement	11,428,572		114,286		2,857,775				2,972,061
-pursuant to exercise of warrants	7,948,036		79,480		2,328,578				2,408,058
-pursuant to exercise of options	50,000		500		5,162				5,662
Stock issuance costs					(263,801)				(263,801)
Employee stock grants	75,000		750		54,750				55,500
Stock based compensation					411,238				411,238
Net loss							(1,062,100)		(1,062,100)
Balance December 31, 2004:	33,875,283	$	338,753	$	8,324,261	$	(3,824,536)	$	4,838,478
-pursuant to private placement	17,000,000		170,000		15,474,243				15,644,243
-pursuant to exercise of warrants	3,496,875		34,969		2,480,709				2,515,678
-pursuant to exercise of options	100,000		1,000		11,122				12,122
Stock issuance costs					(292,370)				(292,370)
Employee stock grants	75,000		750		54,750				55,500
Stock based compensation					541,111				541,111
Net loss							(2,005,091)		(2,005,091)
Balance December 31, 2005:	54,547,158		545,472		26,593,826		(5,829,627)		21,309,671
Issuance of stocks for cash:									
-pursuant to placements	31,589,268		315,892		89,239,795				89,555,687
-pursuant to exercise of options	1,412,000		14,120		370,252				384,372
Stock issuance costs					(6,346,236)				(6,346,236)
Stock based compensation					1,527,361				1,527,361
Net loss							(2,786,040)		(2,786,040)
Balance December 31, 2006:	87,548,426	$	875,484,	$	111,384,998	$	(8,615,667)	$	103,644,815

SEE ACCOMPANYING NOTES

KODIAK OIL & GAS CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	2006	2005	2004
Cash flows from operations			
Net loss	$ (2,786,040)	$ (2,005,091)	$ (1,062,100)
Reconciliation of net loss to net cash provided by operating activities:			
Depletion, depreciation, amortization and abandonment liability accretion	2,173,918	157,868	13,671
Stock based compensation	1,527,361	541,111	411,238
Changes in current assets and liabilities			
Account receivable-Trade	(1,429,204)	(424,322)	(53,505)
Accounts receivable-Accrued Sales	(440,585)	(227,500)	
Prepaid expenses and other	(73,076)	785	
Accounts payable	4,168,775	735,928	281,083
Due to related party			(35,246)
Net cash provided (used by) operating activities	3,141,149	(1,221,221)	(444,859)
Cash flows from investing activities			
Oil and gas properties	(35,426,830)	(11,853,969)	(1,672,300)
Equipment	(52,976)	(124,196)	(106,811)
Restricted investment: designated as restricted	(82,052)	(153,000)	
Restricted investment: undesignated as restricted	10,600		
Net cash used for investing activities	(35,551,258)	(12,131,165)	(1,779,111)
Cash flows from financing activity			
Proceeds from the issuance of shares	89,940,060	18,227,543	5,441,281
Issuance costs	(6,346,236)	(292,370)	(263,801)
Proceeds from (repayment of) related party note payable			(270,654)
Net cash provided by financing activities	83,593,824	17,935,173	4,906,826
Net change in cash and cash equivalents	51,183,715	4,582,787	2,682,856
Cash and cash equivalents at beginning of the period	7,285,548	2,702,763	19,907
Cash and cash equivalents at end of the period	$ 58,469,263	$ 7,285,550	$ 2,702,763
Cash paid for interest	$	$	$ 8,824
Non-cash Items			
Oil & Gas Property accrual included in Accounts Payable	$ 4,605,396	$ 3,306,641	$
Asset retirement obligation	$ 164,503	$ 67,000	$

SEE ACCOMPANYING NOTES

KODIAK OIL & GAS CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 - Organization

Description of Operations

Kodiak Oil & Gas Corp. and its subsidiary ("Kodiak" or the "Company") is a public company dually listed for trading on the American Stock Exchange (AMEX) and the TSX Venture Exchange (TSX-V) and whose corporate headquarters are located in Denver, Colorado, USA. The Company is an independent energy company engaged in the exploration, exploitation, development, acquisition and production of natural gas and crude oil entirely in the western United States.

The Company was incorporated (continued) in the Yukon Territory on September 28, 2001.

Note 2 – Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiary, Kodiak Oil & Gas (USA) Inc. All significant inter-company balances and transactions have been eliminated. The majority of the Corporation's business is transacted in US dollars and, accordingly, the financial statements are expressed in US dollars. The accompanying consolidated financial statements have been prepared in accordance with U.S. generally accepted accounting principles.

Certain amounts in the 2005 and 2004 audited consolidated financial statements have been reclassified to conform to the 2006 audited consolidated financial statement presentation; such reclassifications had no effect on the 2005 or 2004 net loss.

Use of Estimates in the Preparation of Financial Statements

The preparation of the financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure of contingent assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Company bases its estimates on historical experience and on various other assumptions it believes to be reasonable under the circumstances. Although actual results may differ from these estimates under different assumptions or conditions, the Company believes that its estimates are reasonable.

Cash and Cash Equivalents

Cash and cash equivalents consist of all highly liquid investments that are readily convertible to cash and have maturities of three months or less when purchased. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.

Restricted Investment

The restricted investment balance as of December31, 2006 is comprised of: (a) $182,052 certificate of deposit to collateralize a surety bond to provide for state bonding requirements for plugging and abandonment liabilities; and (b) $42,400 certificate of deposit to collateralize the costs of office improvements that will be released over the four year remaining term of the lease at $10,600 per year. At December 31, 2005 the balance was comprised of: (a) $100,000 certificate of deposit to collateralize a surety bond to provide for state bonding requirements for plugging and abandonment liabilities; and (b) $53,000 certificate of deposit to collateralize the costs of office improvements that will be released over the five year term of the lease at $10,600 per year.

KODIAK OIL & GAS CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Concentration of Credit Risk

The Company's cash equivalents and short-term investments are exposed to concentrations of credit risk. The Company manages and controls this risk by investing these funds with major financial institutions. The Company may at times have balances in excess of the federally insured limits.

The Company's receivables are comprised of oil and gas revenue receivables and joint interest billings receivable. The amounts are due from a limited number of entities. Therefore, the collectability is dependent upon the general economic conditions of the few purchasers and joint interest owners. The receivables are not collateralized. However, to date the Company has had minimal bad debts.

Significant Customers

During the year ended December 31, 2006 over 76% of the Company's production was sold to one customer, Eighty Eight Oil LLC. However, the Company does not believe that the loss of a single purchaser, including Eighty Eight Oil, would materially affect the Company's business because there are numerous other purchasers in the area in which the Company sells its production. For the years ended December 31, 2006, 2005 and 2004 purchases by the following companies exceeded 10% of the total oil and gas revenues of the company.

	For the Year Ended December 31,		
	2006	**2005**	**2004**
Eighty Eight Oil LLC	76%	0%	0%
Duke Energy Field Services	11%	37%	0%
Nexen Marketing	0%	38%	0%
Questar Gas Marketing	0%	25%	100%

Oil and Gas Producing Activities

The Company follows the full cost method of accounting for oil and gas operations whereby all costs related to the exploration and development of oil and gas properties are initially capitalized into a single cost center ("full cost pool"). Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling directly related to acquisition and exploration activities. Proceeds from property sales are generally credited to the full cost pool, with no gain or loss recognized, unless such a sale would significantly alter the relationship between capitalized costs and the proved reserves attributable to theses costs. A significant alteration would typically involve a sale of 25% or more of the proved reserves related to a single full costs pool.

Costs capitalized, together with the costs of production equipment, are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves as

determined by independent petroleum engineers. The costs of unproved properties are withheld from the depletion base until such time as they are either developed or abandoned. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations.

For depletion and depreciation purposes, relative volumes of oil and gas production and reserves are converted at the energy equivalent rate of six thousand cubic feet of natural gas to one barrel of crude oil. Under the full costs method of accounting, capitalized oil and gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves plus the cost, or estimated fair value, if lower of unproved properties. Should capitalized costs exceed this ceiling, an impairment is recognized. The present value of estimated future net revenues is computed by applying current prices of oil and gas to estimated future production of proved oil and gas reserves as of period-end, less estimated future expenditures to be incurred in developing and producing the proved reserves assuming the continuation of existing economic conditions. However, subsequent commodity price increases may be utilized to calculate the ceiling value.

As of December 31, 2006, based on oil and gas prices of $50.37 per barrel and $4.53 per mcf, the full cost pool would have exceeded the above described ceiling by approximately $5,200,000. However, subsequent to year end, oil and gas prices increased and the Company completed a well with additional reserves; using these prices, the Company's full cost pool would not have exceeded the ceiling limitation. As a result of the increase in the ceiling amount using subsequent prices and an estimate of the additional proved reserves, the Company has not recorded an impairment of its oil and gas prices at December 31, 2006.

Wells in Progress

Wells in progress at December 31, 2006 and 2005 represent the costs associated with the drilling of wells in Montana, North Dakota and Wyoming. Since the wells have not reached total depth as of December 31 they were classified as wells in progress and were withheld from the depletion calculation and the ceiling test. The costs for these wells will be transferred to proved property when the wells reach total depth and are cased and will become subject to depletion and the ceiling test calculation in future periods.

Impairment of Long-lived Assets

The Company's unproved properties are evaluated quarterly for the possibility of potential impairment. As of December 31, 2006 and 2005 the Company has not recognized any impairment losses.

Other Property and Equipment

Other property and equipment such as office furniture and equipment, vehicles, and computer hardware and software are recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is recorded using the straight-line method over the estimated useful lives of three years for computer equipment, and five years for office equipment and vehicles. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

Fair Value of Financial Instruments

The Company's financial instruments including cash and cash equivalents, accounts receivable and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments.

Revenue Recognition

The Company records revenues from the sales of natural gas and crude oil when the production is produced and sold. The Company may have an interest with other producers in certain properties, in which case the Company uses the sales method to account for gas imbalances. Under this method, revenue is recorded on the basis of gas actually sold by the Company. In addition, the Company records revenue for its share of gas sold by other owners that cannot be volumetrically balanced in the future due to insufficient remaining reserves. The Company also reduces revenue for other owners' gas sold by the Company that cannot be volumetrically balanced in the future due to insufficient remaining reserves. The Company's over and under produced gas balancing positions are considered in the Company's proved oil and gas revenues. Gas imbalances at December 31, 2006 and 2005 were not significant.

Stock-Based Compensation

The Company has historically accounted for stock-based compensation under the provisions of Statement of Financial Accounting Standards ("SFAS") No. 123, Accounting for Stock-Based Compensation. This statement requires us to record an expense associated with the fair value of stock-based compensation. We currently use the

Black-Scholes option valuation model to calculate stock based compensation at the date of grant. Option pricing models require the input of highly subjective assumptions, including the expected price volatility. Changes in these assumptions can materially affect the fair value estimate.

Asset Retirement Obligation

The Company follows SFAS No. 143, "Accounting for Asset Retirement Obligations," which requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it was incurred if a reasonable estimate of fair value could be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The increase in carrying value of a property associated with the capitalization of an asset retirement cost is included in proved oil and gas properties in the consolidated balance sheets. The Company depletes the amount added to proved oil and gas property costs. The future cash outflows associated with settling the asset retirement obligations that have been accrued in the accompanying balance sheets are excluded from the ceiling test calculations. The Company also depletes the estimated dismantlement and abandonment costs, net of salvage values, associated with future development activities that have not yet been capitalized as asset retirement obligations. These costs are also included in the ceiling test calculation. The asset retirement liability will be allocated to operating expense by using a systematic and rational method. As of December 31, 2006 and 2005 the Company has recorded a net asset of $231,431 and $67,000, a related liability of $249,694 and $69,073 respectively (using an 8.5% discount rate and a 2.97% inflation rate). The information below reconciles the value of the asset retirement obligation for the periods presented.

	For the Years Ended December 31, 2006	2005
Balance beginning of period	$ 69,073	$ —
Liabilities incurred	164,503	67,000
Revisions in estimated cash flows	—	—
Accretion expense	16,119	2,073
Balance end of period	$ 249,695	$ 69,073

Recently Issued Accounting Pronouncements:

In February 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments-an amendment of FASB Statements No.133 and 140." SFAS No. 155 amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," and also resolves issues addressed in SFAS No. 133 Implementation Issue No. D1, "Application of Statement 133 to Beneficial Interests in Securitized Financial Assets." SFAS No. 155 was issued to eliminate the exemption from applying SFAS No.133 to interests in securitized financial assets so that similar instruments are accounted for in a similar fashion, regardless of the instrument's form. The Company does not believe that its financial position, results of operations or cash flows will be impacted by SFAS No.155 as the Company does not currently hold any hybrid financial instruments.

In June 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes. The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes. Specifically, the pronouncement prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on the related derecognition, classification, interest and penalties, accounting for interim periods, disclosure and transition of uncertain tax positions. The interpretation is effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 is not expected to have a material impact on the Company's consolidated financial position, results of operations or cash flows; however, the Company is still analyzing the effects of FIN 48.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, "Fair Value Measurements" ("FAS 157"). This Statement defines fair value as used in numerous accounting pronouncements, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosure related to the use of fair value measures in financial statements. The Statement is to be effective for the Company's financial statements issued in 2008; however, earlier application is encouraged. The Company is currently evaluating the timing of adoption and the impact that adoption might have on its financial position or results of operations.

In September 2006, the Securities and Exchange Commission ("SEC") issued Staff Accounting Bulletin No. 108 ("SAB 108"). Due to diversity in practice among registrants, SAB 108 expresses SEC staff views regarding the process by which misstatements in financial statements are evaluated for purposes of determining whether financial statement restatement is necessary. SAB 108 is effective for fiscal years ending after November 15, 2006, and early application is encouraged. The Company does not believe SAB 108 will have a material impact on its financial position or results from operations.

In December 2006, the FASB issued FASB Staff Position ("FSP") EITF 00-19-2,"Accounting for Registration Payment Arrangements." This FSP specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement should be separately recognized and measured in accordance with FASB Statement No. 5, "Accounting for Contingencies". This FSP is effective immediately for registration payment arrangements and the financial instruments subject to those arrangements that are entered into or modified subsequent to December 31, 2006. For registration payment arrangements and financial instruments subject to those arrangements that were entered into prior to December 31, 2006, the guidance in the FSP is effective January 1, 2006 for the Company. The Company does not believe that this FSP will have a material impact on its financial position or results from operations.

On February 15, 2007, the FASB issued SFAS No. 159 "The Fair Value Option for Financial Assets and Financial Liabilities." This Statement establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for the Company's financial statements issued in 2008. The Company is currently evaluating the impact that the adoption of SFAS No. 159 might have on its financial position or results of operations.

Note 3 –Oil and Gas Property

The following table presents information regarding the Company's net costs incurred in the purchase of proved and unproved properties, and in the exploration and development activities:

	For the Years Ended December 31		
	2006	**2005**	**2004**
Property Acquisition costs:			
Proved	$ —	$ 909,637	$ —
Unproved	7,225,875	5,476,788	753,173
Exploration costs	12,534,859	1,027,153	1,604,428
Development costs	17,129,283	7,814,031	—
Total	$ 36,890,017	$ 15,227,609	$ 2,357,601
Total excluding asset retirement obligation	$ 36,725,586	$ 15,160,609	$ 2,357,601

Depletion expense related the proved properties per equivalent BOE of production for the years ended December 31, 2006 and 2005 was $25.63 and $14.45 respectively.

At December 31, the Company's unproved properties consist of leasehold acquisition costs in the following areas:

	For the Years Ended December 31		
	2006	2005	2004
Colorado	$ 962,990	$ —	$ —
Montana	2,233,629	70,346	—
North Dakota	3,089,757	2,915,469	3,180
Wyoming	13,321,098	3,322,088	749,993
	$ 19,607,474	$ 6,307,903	$ 753,173

The following table sets forth a summary of oil and gas property costs not being amortized as of December 31, 2006 by the year in which such costs were incurred:

	Unproved Additions by Year
Prior	$ 353,415
2004	2,004,186
2005	3,950,302
2006	13,299,571
Total	$ 19,607,474

Note 4 – Property Acquisitions

In two separate transactions in 2006, the Company acquired 10,629 gross (9,566 net) acres of mineral leasehold in Sweetwater County, Wyoming for $7.6 million cash. The acreage is part of the Company's Vermillion Basin projects. In October 2006 the Company acquired 5,406 gross (5,406 net) acres in the Sand Wash Basin in Moffat County, Colorado for $973,000 cash. In December 2006, the Company acquired 7,894 gross (5,427 net) acres of mineral leasehold in Dunn County, North Dakota that is prospective for production from the Bakken Formation for $874,000 cash.

The Company's drilling activities are located primarily in the Vermillion Basin area of south western Wyoming and in the Williston Basin in Montana and North Dakota. The Company plans to drill approximately 9 gross wells (7.5 net wells) in the Vermillion Basin and 9 gross wells (4.88 net wells) in the Williston Basin during 2007. The unproved costs associated with the Company's drilling projects will be transferred to proved properties as the wells are drilled during the next five to ten years.

Wells in Progress:

The following table reflects the net changes in capitalized additions to wells in progress during 2006, 2005, and 2004, and does not include amounts that were capitalized or reclassified to producing wells in the same period.

	For the Years Ended December 31	
	2006	2005
Beginning balance at January 1,	$ 2,461,087	$ —
Additions to capital wells in progress costs pending the determination of proved reserves	7,700,415	2,461,087
Reclassifications to sells, facilities, and equipment based on the determination of proved reserves to full cost pool	(2,461,087)	—
Ending balance December 31,	$ 7,700,415	$ 2,461,087

The following table provides an aging of capitalized wells in progress costs based on the date the drilling was completed and the number of projects for which wells in progress have been capitalized since the completion of drilling.

	For the Years Ended December 31	
	2006	2005
Wells in progress capitalized for one year or less	$ 7,700,415	$ 2,461,087
Wells in progress capitalized for one year or more	—	—
Ending balance at December 31,	$ 7,700,415)	$ 2,461,087
Number of projects with wells in progress that have been capitalized less than one year	3	5

Note 5 – Common Stock

In March 2006, the Company issued 19,514,268 common shares in a private placement to a group of accredited investors for gross proceeds of $39,444,438. The Company paid commissions and expenses of $2,907,199. In December 2006, the Company issued 12,075,000 common shares in a public placement for gross proceeds of $50,111,250. The Company paid commission and expenses of $3,439,037.

In December 2005, the Company issued 17,000,000 common shares in a private placement to a group of accredited investors for gross proceeds of $15,644,243. The Company paid $292,370 in commissions and expenses. In 2005, the Company issued 3,496,875 common shares through the exercise of warrants for gross proceeds of $2,515,678.

In March 2004, the Company issued 11,428,572 common shares in a private placement to a group of accredited investors for gross proceeds of $2,972,061. The Company paid $263,801 in commissions and expenses. During 2004, the Company issued 7,948,036 common shares through the exercise of warrants for gross proceeds of $2,408,058.

During 2006, the Company issued 1,412,000 common shares through the exercise of options for gross proceeds of $384,372. During 2005, the Company issued 100,000 common shares through the exercise of employee options for gross proceeds of $12,122.

Note 6 – Compensation Plan

Stock-based Compensation Plan

The Company has a stock-based compensation plan whereby share purchase options may be granted with an exercise price equal to the trading value when granted. The total number of share purchase options outstanding cannot exceed 10% of the total number of shares issued.

For the years ended December 31, 2006, 2005 and 2004, the Company recorded stock-based compensation of $1,527,361, $541,111, and $411,238 respectively.

The following assumptions were used for the Black-Scholes model:

	For the Periods Ended December 31, 2006	December 31, 2005	December 31, 2004
Risk free rates	4.56-5.25%	4.3%	3.75%
Dividend yield	0%	0%	0%
Expected volatility	62.79-64.92%	81.34%	110.40%
Weighted average expected stock option life	3.36 yrs	2.5 yrs	4 yrs
The weighted average fair value at the date of grant for stock options granted is as follows:			
Weighted average fair value per share	$ 1.58	$ 0.60	$ 0.23
Total options granted	2,110,000	900,000	1,751,500
Total weighted average fair value of options granted	$ 3,339,312	$ 541,111	$ 406,031

Note 6 – Stock Options

A summary of the stock options outstanding is as follows:

	Number of Options	Weighted Average Exercise Price
Balance outstanding at December 31, 2004	3,138,500	$ 0.42
Granted	900,000	$ 1.09
Exercised	(100,000)	$ 0.14
Balance outstanding at December 31, 2005	3,938,500	$ 0.58
Granted	2,110,000	$ 3.41
Exercised	(1,412,000)	$ 0.27
Balance outstanding at December 31, 2006	4,636,500	$ 1.96
Options exercisable at December 31, 2006	3,091,000	$ 1.38

At December 31, 2006, stock options outstanding are as follows:

Exercise Price	Number of Shares	Expiry Date
$0.14	125,000	December 9, 2008
$0.45	1,000,000	March 1, 2009
$0.90	501,500	August 23, 2009
$1.09	900,000	October 16, 2010
$2.11	50,000	March 12, 2011
$3.18	1,300,000	April 12, 2011
$4.03	285,000	June 27, 2011
$3.81	475,000	October 31, 2011
	4,636,500	

	For the Years Ended December 31,			
	2006		2005	
	Oil or Condensate (Bbl)	Gas (Mcf)	Oil or Condensate (Bbl)	Gas (Mcf)
Discoveries and extensions	230,422	1,674,003	524,408	2,866,967
Production	(62,983)	(116,277)	(2,699)	(31,751)
End of year	532,902	2,402,433	521,709	2,835,216

Standardized Measure of Discounted Future Net Cash Flows (Unaudited):

SFAS No. 69, "Disclosures about Oil and Gas Producing Activities," prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company has followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying benchmark prices and costs, including transportation, quality and basis differentials, in effect at year-end to the year-end estimated quantities of oil and gas to be produced in the future. Each property the Company operates is also charges with field-level overhead in the estimated reserve calculation. Estimated future income taxes are computed using current statutory income tax rates, including consideration for estimated future statutory depletion. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

Future operating costs are determined based on estimates of expenditures to be incurred in developing and producing the proved oil and gas reserves in place at the end of the period, using year-end costs and assuming continuation of existing economic conditions, plus Company overhead incurred attributable to operating activities.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the Securities and Exchange Commission. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates are basis for the valuation process. The following prices, as adjusted for transportation, quality and basis differentials, were used in the calculation of the standardized measure: Gas (per Mcf) $4.53; Oil (per Bbl) $50.37.

The following summary sets forth the Company's future net cash flows relating to proved oil and gas reserves based on the standardized measure prescribed in SFAS No. 69:

	Year Ended December 31, 2006	Year Ended December 31, 2005
Future cash inflows	$ 37,634,700	$ 51,182,477
Future production costs	(8,920,900)	(13,355,083)
Future development costs	(2,492,500)	(5,342,500)
Future income taxes	—	(10,980,498)
Future net cash flows	26,221,300	21,504,396
10% annual discount	(6,631,500)	(7,301,589)
Standardized measure of discounted future net cash flows	$ 19,589,800	$ 14,202,807

The principle sources of change in the standardized measure of discounted future net cash flows are:

	Year ended December 31, 2006 United States	Year ended December 31, 2005 United States
Balance at beginning of period	14,202,806	—
Sales of oil and gas, net	(3,194,424)	(163,695)
Net change in prices and production costs	(4,965,063)	—
Net change in future development costs	630,351	—
Extensions and discoveries	11,720,816	18,320,720
Revisions of previous quantity estimates	(7,798,876)	—
Previously estimated development costs incurred	2,187,500	—
Net change in income taxes	3,954,218	(3,954,218)
Accretion of discount	2,107,952	—
Other	744,520	—
Balance at end of period	$ 19,589,800	$ 14,202,807

Note 10 – Differences Between Canadian and United States Accounting Principles

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America which differ in certain respects with those principles and practices that the Company would have followed had its financial statements been prepared in accordance with accounting principles and practices generally accepted in Canada.

The Company's accounting principles generally accepted in the United States of American differ from accounting principles generally accepted in Canada as follows:

a) Stock-based Compensation

The Company grants stock options at exercise prices equal to the fair market value of the Company's stock at the date of the grant. Under Statement of Financial Accounting Standards No. 123 the Company had accounted for its employee stock options under the fair value method. The fair value is determined using an option pricing model that takes into account the stock price at the grant date, the exercise price, the expected life of the option, the volatility of the underlying stock and the expected dividends, and the risk-free interest rate over the expected life of the option.

As a result of the new recommendations of the Canadian Institute of Chartered Accountants regarding accounting for stock-based compensation, there is no difference between Canadian GAAP and US GAAP for the years ended December 31, 2006, 2005 and 2004.

b) Comprehensive Loss

US GAAP requires disclosure of comprehensive loss which, for the Company is net loss under US GAAP plus the change in cumulative translation adjustment under US GAAP.

The concept of comprehensive loss does not come into effect until fiscal years beginning on or after October 1, 2006 for Canadian GAAP.

Management does not believe that any recently issued, not yet effective, Canadian accounting standards if currently adopted could have a material effect on the accompanying financial statements.

Note 11 –Quarterly Financial Information (Unaudited):

The Company's quarterly financial information for fiscal 2006, 2005 and 2004 is as follows:

		First Quarter		Second Quarter		Third Quarter		Fourth Quarter
Year Ended December 31, 2006								
Total revenue	$	1,012,251	$	1,125,266	$	1,273,035	$	1,554,616
Net Revenue from oil and gas operations	$	908,578	$	862,099	$	1,040,589	$	1,347,839
Income/(Loss) from Operations	$	(5,515)	$	(1,008,110)	$	(389,287)	$	(1,383,128)
Basic and diluted net loss per share	$	—	$	(.01)	$	(0.01)	$	(0.02)
Year Ended December 31, 2005								
Total revenue	$	8,647	$	36,222	$	127,373	$	280,893
Net Revenue from oil and gas operations	$	—	$	13,545	$	87,971	$	264,064
Income/(Loss) from Operations	$	(327,084)	$	(488,876)	$	(52,252)	$	(1,136,879)
Basic and diluted net loss per share	$	(0.01)	$	(0.01)	$	(0.01)	$	(0.01)
Year Ended December 31, 2004								
Total revenue	$	—	$	—	$	—	$	—
Net Revenue from oil and gas operations	$	—	$	—	$	—	$	—
Income/(Loss) from Operations	$	(396,757)	$	(152,582)	$	(130,315)	$	(382,446)
Basic and diluted net loss per share	$	(.01)	$	(.01)	$	(.01)	$	(.01)

Note 12 – Subsequent Events

In February 2007 the Company entered into a lease agreement for office facilities that expires June 2012. The commencement of this lease agreement will simultaneously terminate the existing lease commitment per Note 7.

The following table shows the annual rentals per year for the life of the lease:

2007	$	117,000
2008		208,400
2009		218,500
2010		232,000
2011		247,700
2012		128,600
Total	$	1,152,200

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Under the supervision and with the participation of our management, we evaluated the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, or the "Exchange Act") as of December 31, 2006. On the basis of this review, our management concluded that our disclosure controls and procedures are effectively designed to give reasonable assurance that the information we are required to disclose in reports that we file under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and to ensure that information required to be disclosed in the reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, in a manner that allows timely decisions regarding required disclosure.

There were no changes in the Company's internal controls over financial reporting that occurred in the fourth fiscal quarter of 2006 that materially affected or were reasonably likely to materially affect, its internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information responsive to Items 401, 405, 406 and 407 of Regulation S-K to be included in our definitive Proxy Statement for our 2007 Annual Meeting of Shareholders, to be filed within 120 days of December 31, 2006 pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the "2007 Proxy Statement"), is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information responsive to Items 402 and 407 of Regulation S-K to be included in our 2007 Proxy Statement is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information responsive to Items 201(d) and 403 of Regulation S-K to be included in our 2007 Proxy Statement is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information responsive to Items 404 and 407 of Regulation S-K to be included in our 2007 Proxy Statement is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information responsive to Item 9(e) of Schedule 14A to be included in our 2007 Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents Filed With This Report

1. FINANCIAL STATEMENTS

The following consolidated financial statements of the Company are filed as a part of this report:

2. FINANCIAL STATEMENT SCHEDULES
None.

3. EXECUTIVE COMPENSATION PLANS AND ARRANGEMENTS
Kodiak Oil & Gas Corp. Incentive Stock Option Plan identified in the exhibit list below.

(b) Exhibits

Exhibit Number	Description
3.1(1)	Certificate of Continuance of Kodiak Oil & Gas Corp., dated September 20, 2001
3.2(1)	Articles of Continuation of Kodiak Oil & Gas Corp.
3.3(1)	General By-Law No. 1
4.1(1)	Kodiak Oil & Gas Corp. Incentive Stock Option Plan
10.1(1)	Second Amendment of Lease, dated May 27, 2005, between Kodiak Oil & Gas (USA) Inc. and Brookfield Denver Inc.
10.3(1)	Agency Agreement, dated February 22, 2005 between the Company and Jennings Capital
10.4(1)	Agency Agreement, dated January 26, 2004 between the Company and Jennings Capital
10.6(2)	Purchase and Sale Agreement between CP Resources LLC and Warren Resources, Inc. dated June 2003
10.7(2)	Purchase and Sale Agreement between Fancher Resources LLC and Kodiak Oil & Gas (USA) Inc. dated December 6, 2005
10.8(2)	Purchase and Sale Agreement between Staghorn Energy, LLC and Kodiak Oil & Gas (USA) Inc. dated December 6, 2005
10.9(2)	Letter from Hallador Petroleum Company to Kodiak Oil & Gas dated November 21, 2005
10.10(3)	Letter Agreement between CP Resources LLC and Kodiak Oil & Gas Corp. dated May 31, 2002
10.11(3)	Letter Agreement between CP Resources LLC and Kodiak Oil & Gas Corp. dated September 21, 2001
10.12(3)	Letter Agreement between CP Resources LLC and Kodiak Oil & Gas Corp. dated June 19, 2003
10.13(4)	Form of Stock Purchase Agreement, dated as of March 3, 2006, among Kodiak Oil & Gas Corp. and certain investors
10.14	Fourth Amendment to Lease, dated February 14, 2007, between Transwestern Broadreach WTC, LLC and Kodiak Oil & Gas (USA) Inc.
14.1(4)	Code of Business Conduct and Ethics
16.1(5)	Letters regarding change in certifying accountant filed on May 8, 2006
21.1(6)	Subsidiaries of the Registrant
23.1	Consent of Hein & Associates LLP

Exhibit Number	Description
23.2	Consent of Amisano Hanson, Chartered Accountants
23.3	Consent of Netherland Sewell & Associates, Inc.
23.4	Consent of Sproule Associates Inc.
31	Certification of the Chief Executive Officer and Chief Accounting Officer required by Rule 13a-14(a) or Rule 15d-14(a)
32	Certification of the Chief Executive Officer and Chief Accounting Officer pursuant to 18 U.S.C. Section 1350

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(1) Incorporated by reference to the Registrant's Registration Statement on Form 20-F (SEC File No. 000-51635), filed on November 23, 2005.

(2) Incorporated by reference to Amendment No. 2 to the Registrant's Registration Statement on Form 20-F (SEC File No. 000-51635), filed on February 8, 2006.

(3) Incorporated by reference to Amendment No. 3 to the Registrant's Registration Statement on Form 20-F (SEC File No. 000-51635), filed on March 3, 2006.

(4) Incorporated by reference to the Registrant's Annual Report on Form 20-F for the Fiscal Year Ended December 31, 2005 (SEC File No. 000-51635), filed on May 2, 2006.

(5) Incorporated by reference to the Registrant's Form 6-K (SEC File No. 000-51635), filed on May 8, 2006.

(6) Incorporated by reference to the Registrant's Registration Statement on Form F-1 (SEC File No. 333-138932), filed on November 22, 2006.

GLOSSARY OF TERMS

The following technical terms defined in this section are used throughout this Form 10-K:

(a) "2-D seismic or 2-D data" means seismic data that is acquired and processed to yield a two-dimensional cross-section of the subsurface.

(b) "3-D seismic or 3-D data" means seismic data that is acquired and processed to yield a three-dimensional picture of the subsurface.

(c) "Bbl" means one stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

(d) "BOE" means barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

(e) "Bore hole" means the wellbore itself, including the openhole or uncased portion of the well. Bore hole may refer to the inside diameter of the wellbore wall, the rock face that bounds the drilled hole.

(f) "Coalbed methane" is methane gas produced as a result of the coalification process, whereby plant material is progressively converted to coal, generating large quantities of methane-rich gas which are stored within the coal.

(g) "Completion" means the installation of permanent equipment for the production of oil or natural gas.

(h) "Delay rental" means a payment made to the lessor under a non-producing oil and natural gas lease at the end of each year to continue the lease in force for another year during its primary term.

(i) "Developed acreage" means the number of acres that are allocated or assignable to producing wells or wells capable of production.

(j) "Development well" means a well drilled to a known producing formation in a previously discovered field, usually offsetting a producing well on the same or an adjacent oil and natural gas lease.

(k) "Dry hole" means a well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

(l) "Exploratory well" means a well drilled either (a) in search of a new and as yet undiscovered pool of oil or gas or (b) with the hope of significantly extending the limits of a pool already developed (also known as a "wildcat well").

(m) "Farmin" means an agreement which allows a party to earn a full or partial working interest (also knows as an "earned working interest") in an oil and natural gas lease in return for providing exploration funds.

(n) "Farmout" means an agreement whereby the owner of the leasehold or working interest agrees to assign a portion of his interest in certain acreage subject to the drilling of one or more specific wells or other performance by the assignee as a condition of the assignment. Under a farmout the owner of the leasehold or working interest may retain some interest such as an overriding royalty interest, an oil and natural gas payment, offset acreage or other type of interest.

(o) "Federal Unit" means acreage under federal oil and natural gas leases subject to an agreement or plan among owners of leasehold interests, which satisfies certain minimum arrangements and has been approved by an authorized representative of the U.S. Secretary of the Interior, to consolidate under a cooperative unit plan or agreement for the development of such acreage comprising a common oil and natural gas pool, field or like area, without regard to separate leasehold ownership of each participant and providing for the sharing of costs and benefits on a basis as defined in such agreement or plan under the supervision of a designated operator.

(p) "Fee land" means the most extensive interest that can be owned in land, including surface and mineral (including oil and natural gas) rights.

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

(r) "Fracturing" means mechanically inducing a crack or surface of breakage within rock not related to foliation or cleavage in metamorphic rock in order to enhance the permeability of rocks greatly by connecting pores together.

(s) "Gas" or "Natural gas" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain liquids.

(t) "Gross Acres" or "Gross Wells" means the total acres or wells, as the case may be, in which we have a working interest.

(u) "Hydraulic fracturing" means a procedure to stimulate production by forcing a mixture of fluid and proppant (usually sand) into the formation under high pressure. This creates artificial fractures in the reservoir rock, which increases permeability and porosity.

(v) " "Horizontal drilling" means a well bore that is drilled laterally.

(w) "Landowner royalty" means that interest retained by the holder of a mineral interest upon the execution of an oil and natural gas lease which usually amounts to 1/8 of all gross revenues from oil and natural gas production unencumbered with any expenses of operation, development, or maintenance.

(x) "Leases" means full or partial interests in oil or gas properties authorizing the owner of the lease to drill for, produce and sell oil and natural gas in exchange for any or all of rental, bonus and royalty payments. Leases are generally acquired from private landowners (fee leases) and from federal and state governments on acreage held by them.

(y) "Mcf" is an abbreviation for "1,000 cubic feet," which is a unit of measurement of volume for natural gas.

(z) "Methane" means a colorless, odorless, flammable gas, CH_4, the first member of the methane series.

(aa) "Net Acres" or "Net Wells" is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

(bb) "Net revenue interest" means all of the working interests less all royalties, overriding royalties, non-participating royalties, net profits interest or similar burdens on or measured by production from oil and natural gas.

(cc) "NYMEX" means New York Mercantile Exchange.

(dd) "Overriding royalty" means an interest in the gross revenues or production over and above the landowner's royalty carved out of the working interest and also unencumbered with any expenses of operation, development or maintenance.

(ee) "Operator" means the individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease.

(ff) "Paid-Up Lease" means a lease for which the aggregate lease payments are paid in full on or prior to the commencement of the lease term.

(gg) "Payout" means the point in time when the cumulative total of gross income from the production of oil and natural gas from a given well (and any proceeds from the sale of such well) equals the cumulative total cost and expenses of acquiring, drilling, completing, and operating such well, including tangible and intangible drilling and completion costs.

(hh) "Prospect" means a geological area which is believed to have the potential for oil and natural gas production.

(ii) "PV-10 value" means the present value of estimated future gross revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated (unless such prices or costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period.

(jj) "Productive well" means a well that is producing oil or gas or that is capable of production.

(kk) "Proved developed reserves" means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

(ll) "Proved reserves" means the estimated quantities of oil, gas and gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

(mm) "Proved undeveloped reserves" means reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(nn) "Recompletion" means the completion for production from an existing wellbore in a formation other than that in which the well has previously been completed.

(oo) "Reserve life" represents the estimated net proved reserves at a specified date divided by actual production for the preceding 12-month period.

(pp) "Royalty" means the share paid to the owner of mineral rights, expressed as a percentage of gross income from oil and natural gas produced and sold unencumbered by expenses relating to the drilling, completing and operating of the affected well.

(qq) "Royalty interest" means an interest in an oil and natural gas property entitling the owner to shares of oil and natural gas production, free of costs of exploration, development and production operations.

(rr) "Undeveloped acreage" means lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether or not such acreage contains proved reserves.

(ss) "Undeveloped leasehold acreage" means the leased acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains estimated net proved reserves.

(tt) "Working interest" means an interest in an oil and natural gas lease entitling the holder at its expense to conduct drilling and production operations on the leased property and to receive the net revenues attributable to such interest, after deducting the landowner's royalty, any overriding royalties, production costs, taxes and other costs.

SIGNATURES

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

KODIAK OIL & GAS CORP.
(Registrant)

Date: March 26, 2007

By: /s/ Lynn A. Peterson

Lynn A. Peterson
President
(principal executive officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

By: /s/ Lynn A. Peterson Lynn A. Peterson	President (principal executive officer and principal financial officer)	March 26, 2007
By: /s/ James E. Catlin James E. Catlin	Vice President and Secretary	March 26, 2007
By: /s/ Herrick K. Lidstone, Jr. Herrick K. Lidstone, Jr.	Director	March 26, 2007
By: /s/ Rodney D. Knutson Rodney D. Knutson	Director	March 26, 2007
By: /s/ Hugh J. Graham Hugh J. Graham	Director	March 26, 2007
By: /s/ Don McDonald Don McDonald	Director	March 23, 2007

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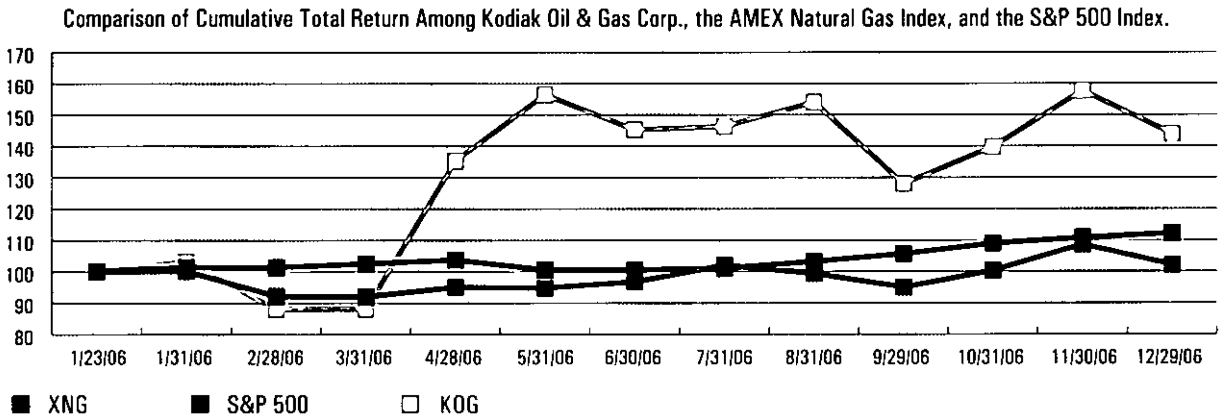
Performance Graph

The following graph compares the cumulative total stockholder return on the Common Stock against the total return of the S&P 500 Index and the AMEX Natural Gas Index for the period of January 23, 2006 to December 31, 2006. The graph assumes that $100 was invested in the Common Stock and each index on January 23, 2006 and that all dividends were reinvested.



Directors and Officers

Lynn A. Peterson—President, Chief Executive Officer and Director

James E. Catlin—Chief Operating Officer and Chairman of the Board of Directors

Hugh J. Graham[1]—Director
President and CEO of Murex Corporation

Rodney D. Knutson[1]—Director
Vice President and General Counsel of The Harrison Western Group

Herrick K. Lidstone, Jr.[1]—Director
Attorney with Burns, Fisa & Will, P.C.

Don A. McDonald, CPA[1]—Director
Associate with Albrecht & Associates, Inc.

Corporate Office

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Registered Office

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Y1A 2A9 Canada

Auditors

Hein & Associates LLP
Denver, Colorado, USA

Legal Counsel

Dorsey & Whitney LLP
Seattle, Washington, USA

Miller Thomson LLP
Vancouver, British Columbia, Canada

Independent Reservoir Engineers

Netherland, Sewell & Associates, Inc.
Dallas, Texas, USA

[1] Member of the Audit, Compensation and Nominating Committees.

Corporate Information

Stock Exchange Listings
The American Stock Exchange, "KOG"

Registrar and Transfer Agent
Computershare Investor Services, Inc.
Denver, Colorado

Contact transfer agent for information regarding changes of address, registration of shares, transfers or lost certificates, or for information about your shareholder account.

Form 10-K
The enclosed Form 10-K of the Company does not include the exhibits that were filed with the U.S. Securities and Exchange Commission. A complete copy of the Form 10-K, including all exhibits, may be obtained by writing to the Company or may be accessed on Kodiak's website at www.kodiakog.com.

Code of Business Conduct and Ethics
Please reference the Corporate Governance section on Kodiak's website at www.kodiakog.com for important information regarding the Company's Code of Business Conduct and Ethics. Additionally, a copy may be obtained by writing to the Company.

Annual Meeting

Kodiak's annual general meeting will be held at:

The University Club
1673 Sherman Street
Denver, Colorado 80203
Room: Lounge Room
Date: May 24, 2007
Time: 10:00 AM

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KODIAK
OIL & GAS CORP.

END