BPI Energy Holdings, Inc.
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Prospectus Supplement
to Separate Prospectuses dated
May 11, 2006

This prospectus supplement amends and supplements the following prospectuses of BPI Energy Holdings, Inc. (BPI):

The prospectus dated May 11, 2006 that is contained in the Post-Effective Amendment No. 1 to Form S-1 registration statement filed by BPI with the Securities and Exchange Commission (the SEC) on May 11, 2006 and declared effective by the SEC on May 22, 2006 (Registration No. 333-125483), which covers the offer and sale of 16,595,200 shares of common stock of BPI by the selling shareholders named therein (the 125483 Prospectus); and

The prospectus dated May 11, 2006 that is contained in the Post-Effective Amendment No. 1 to Form S-1 registration statement filed by BPI with the SEC on May 11, 2006 and declared effective by the SEC on May 22, 2006 (Registration No. 333-130122), which covers the offer and sale of 18,000,000 shares of common stock of BPI by the selling shareholders named therein (the 130122 Prospectus).

The 125483 Prospectus, along with this prospectus supplement, together constitute the prospectus required to be delivered by Section 5(b) of the Securities Act of 1993 with respect to the offering and sale of common stock of BPI covered by the 125483 Prospectus. The 130122 Prospectus, along with this prospectus supplement, together constitute the prospectus required to be delivered by Section 5(b) of the Securities Act of 1993 with respect to the offering and sale of common stock of BPI covered by the 130122 Prospectus.

You should rely only on the information contained in this prospectus supplement and the related prospectus identified above. We have not authorized any other person to provide you with information that is different from or in addition to that contained in this prospectus supplement and the related prospectus. If anyone provides you with different or inconsistent information, you should not rely on it.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus supplement is truthful or complete. Any representation to the contrary is a criminal offense.

The date of this prospectus supplement is November 3, 2006

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About this Prospectus Supplement

Our disclosure consists of two parts. The first part is either the 125483 Prospectus or the 130122 Prospectus, depending upon which prospectus is required to be delivered to you by the selling shareholder. The second part is this prospectus supplement. You should review both this prospectus supplement and the related prospectus in their entirety before making a decision to invest in shares of BPI s common stock. This prospectus supplement sets forth BPI s financial statements for the year ended July 31, 2006, management s discussion and analysis of financial condition and results of operations, and recent developments in BPI s business since the dates of the respective prospectuses identified above. In the event of any inconsistency between this prospectus supplement and the related prospectus, you should rely on the information contained in this prospectus supplement.

Selected Historical Financial Data

The following sets forth our selected historical financial data as of July 31, 2006, 2005, 2004, 2003 and 2002 and for our five fiscal years then ended, which has been derived from our financial statements for those years. Our financial statements as of July 31, 2006 and 2005 and for our fiscal years ended July 31, 2006 and 2005 and related notes thereto have been audited by Meaden & Moore, Ltd., an independent registered public accounting firm. Our financial statements as of July 31, 2004, 2003 and 2002 and for our fiscal years ended July 31, 2004, 2003 and 2002 and related notes thereto have been audited by De Visser Gray, an independent registered public accounting firm.

This information should be read together with the section of this prospectus supplement entitled Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and related notes included elsewhere in this prospectus supplement.

	For the Year Ended July 31,				
	2006	2005	2004	2003	2002
Statement of Operations Data:					
Gas sales(1)	$ 1,126,477	$ 117,835	$	$	$
Stock-based compensation expense	1,377,440	3,344,738	193,796	515,286	439,860
Loss before income taxes	(8,836,245)	(6,120,821)	(1,091,227)	(1,109,218)	(1,245,853)
Net loss	(8,836,245)	(5,396,351)	(793,116)	(934,305)	(1,129,209)
Net loss per common share	(0.14)	(0.14)	(0.03)	(0.04)	(0.06)
Weighted average number of shares outstanding	62,789,319	37,665,019	25,007,237	21,485,381	18,300,433

	As of July 31,				
	2006	2005	2004	2003	2002
Balance Sheet Data:					
Total assets	$ 49,051,980	$ 23,527,712	$ 9,382,977	$ 6,328,178	$ 5,418,158
Long-term notes payable (including current maturities)	216,015	549,822	462,177	378,174	
Cash dividends per common share					

(1) Gas sales commenced in January 2005.

Management s Discussion and Analysis of Financial Condition and Results of Operations

The following Management s Discussion and Analysis (MD&A) is intended to help the reader understand our business, financial condition, results of operations, liquidity and capital resources. MD&A is provided as a supplement to, and should be read in conjunction with, the other sections of this prospectus supplement and our consolidated financial statements and related notes. Our MD&A includes the following sections:

Overview and Outlook a general description of our business; drilling plans and capital expenditures; key areas of management focus; measurements; and opportunities, challenges and risks.

Critical Accounting Policies a discussion of accounting policies that require critical judgments and estimates.

Results of Operations an analysis of our consolidated results of operations for the three years presented in our financial statements.

Liquidity and Capital Resources an analysis of our cash flows, sources and uses of cash, contractual obligations and commercial commitments.

Overview and Outlook

We are an independent energy company incorporated under the laws of British Columbia, Canada and primarily engaged, through our wholly owned U.S. subsidiary, BPI Energy, Inc., in the exploration, production and commercial sale of coalbed methane (CBM). Our exploration and production efforts are concentrated in the Illinois Basin (the Basin). Our Canadian activities are limited to administrative reporting obligations to the province of British Columbia and regulatory reporting to the British Columbia Securities Commission.

As of July 31, 2006, we owned or controlled CBM rights, through mineral leases, options to acquire mineral leases, a farm-out agreement and ownership of a CBM estate, covering approximately 500,000 total acres in the Basin (a substantial majority of which was undeveloped as of July 31, 2006). We are focused on 12 Pennsylvanian coal seams that we regard as having commercial CBM potential. The seams in the acreage covered by our CBM rights have an aggregate thickness of 11-27 feet with a 19-foot median. We plan to complete several individual seams per well that range from two to nine feet thick each. Gas desorption tests of these coals have yielded 13-113 scf/ton with a 63 scf/ton median. Extensive permeability testing of individual seams (before stimulation) indicates a range of 0.2-75 millidarcies and median of 4 millidarcies.

The state of Illinois (which includes most of the Basin) is estimated to be the number two state in the U.S. in terms of coal reserves; however, coal in the Basin is high in sulfur, discouraging coal mining operations. Recent advances in technology that can reduce the sulfur content of the coal and higher coal prices are combining to make coals in the Basin potentially attractive to mining operations. Although coal mining activities take priority over CBM operations in most of our acreage, we attempt to coordinate and plan our drilling and production activities in conjunction with the owners of the coal in order to minimize any potential disruptions. In addition, because of the long lead times involved in coal mining projects, our substantial acreage position, and our ability to be flexible with the timing and siting of our wells, we believe we can plan our work around coal mining operations in the vicinity of our projects.

We have been involved in the first two projects in the Basin that have commercially produced and sold CBM. We are the only company currently commercially producing and selling CBM in the state of Illinois and one of only two companies currently commercially producing and selling CBM in the Illinois Basin. We believe our position as the first mover has enabled us to secure a substantial and favorable acreage position at costs that we believe compare very favorably to other CBM basins that are more mature in terms of production history.

We are an early stage CBM exploration and production company. We commenced CBM sales from our first producing wells in January 2005. Gas sales during the fiscal year ended July 31, 2005 were $117,835. Gas sales were $1,126,477 for the fiscal year ended July 31, 2006, an increase of 856%. From early 2002 until 2005, our strategic focus was on building our acreage footprint in the Basin. We were built around the primary strategic objective of acquiring CBM rights in the Basin. As we began accumulating CBM rights we began testing our acreage to determine its CBM potential. Having accumulated CBM rights to approximately 500,000 acres in the

Basin and conducting extensive testing at our Southern Illinois Basin Project, we embarked (in late 2004) on a pilot production program at our Southern Illinois Basin Project. Encouraged by the results, we expanded our drilling and production activities and began installing the infrastructure necessary to enable us to begin sales of CBM at our Southern Illinois Basin Project.

As our drilling and production operations have grown, we have not abandoned our goal of adding additional acreage and mineral rights. However, we have committed ourselves to transitioning BPI from a company focused primarily on the acquisition of mineral rights to a company focused on expanding our drilling and production operations and growing our reserves. To accomplish this transition, we recognized that we needed to obtain additional capital, resources and technical expertise. We believe that we have made substantial progress in achieving these goals. In September 2005, we sold 18,000,000 common shares and raised approximately $28,000,000. In April 2006, we hired Jim Craddock as our Senior Vice President of Operations. Jim was with Burlington Resources for over 20 years, last serving as Chief Engineer. Jim immediately began building an in-house technical team by bringing in a geologist and three engineers, all with extensive experience in successful CBM projects in basins located in the United States and Canada. Our new technical team has over 130 years of experience in CBM exploration and development that they bring to BPI.

In April 2006, we initiated our second development front when we began drilling 10 pilot development wells in Shelby County at our Northern Illinois Basin Project. Our CBM rights in the Northern Illinois Basin Project cover 351,487 acres in Montgomery, Shelby, Christian, Fayette and Macoupin counties in Illinois, which are located in the north central part of the Basin. We believe that there are 12 prospective coal seams thick enough for commercial production at this project. The thickest seam, the Herrin Coal seam, is up to nine feet thick and has been mined in shallow parts of the Basin. We believe that a single thick seam such as this may offer an attractive target for horizontal drilling.

We are not currently generating net income or positive cash flow from operations. Although we capitalize exploration and development costs, we have historically experienced significant losses. The primary costs that generated these losses were compensation-related expenses and general and administrative expenses. Even if we achieve increased revenues and positive cash flow from operations in the future, we anticipate increased exploration, development and other capital expenditures as we continue to explore and develop our mineral rights.

We anticipate that the number of wells we drill during the fiscal year ending July 31, 2007 will be dependent to a significant degree on the data we obtain from our recently completed 10-well pilot program at our Northern Illinois Basin Project (Northern Project) as well as data obtained from five test wells we have recently drilled on other leases in our Western Illinois Basin Project (Western Project) and Northern Project. Our capital expenditure budget for our 2007 fiscal year is a range that totals $12.0 million to $30.0 million. These amounts correspond to drilling 58 wells at the low end of the range and 123 wells at the upper end. These amounts include installing a gathering system and processing yard to handle the anticipated production from the 10-well pilot program at our Northern Project and additional pilot wells and/or production wells at our three current projects. Our cash balance at July 31, 2006 of $19,279,015 is insufficient to fully fund the high end of the range of forecasted capital expenditures and net cash used by operating activities during our 2007 fiscal year or our operations beyond that date. Therefore, we will likely need to raise additional financing in the near future. We currently do not have any specific plans to raise financing in support of our operations. Although management has no specific plans in place to raise the additional capital necessary to fund our plan of operations and forecasted capital expenditures, management anticipates raising the additional required capital through a combination of additional stock sales, the issuance of debt securities, borrowing and/or entering into joint ventures. Management s focus for fiscal year 2007 will be to:

- obtain test data and initiate pilot projects that demonstrate the commercial potential of CBM at our various acreage blocks and projects in the Illinois Basin;

reduce well drilling and completion costs;

increase total company reserves; and

grow total production.

Gathering test data and siting pilot projects based on this data should lead to proving project viability in multiple areas in the Illinois Basin. These pilot projects should have the potential to grow into development projects that will increase total company reserves and production. As we drill new wells, our production should continue to increase, as the new wells come online and our existing wells continue to dewater. As our production increases in the future, we should be positioned to generate positive cash flow from our operations.

A thorough evaluation of the geological assets that we control should lead to the evaluation and implementation of more cost effective drilling and completion techniques that can be implemented to reduce overall costs, increase resource recovery and total reserves and improve internal rates of return from development projects.

We currently control approximately 500,000 acres of CBM rights and, assuming 80-acre vertical well spacing and the development of all of our acreage, have the possibility of up to 6,000 drilling locations. With our potential for drilling locations, we expect that our drilling activities will be taking place over many years. The type of test data we are interested in developing across all of our projects includes measurements of permeability, gas content and net pay (i.e., thickness of coal seams from which we believe CBM can be commercially produced). Our focus is to increase our technical and operational knowledge of the Illinois Basin and our acreage rights to assist us in (i) establishing the value of our CBM assets and (ii) optimizing the production we can obtain from our wells after we bring them online. The technical team we have assembled has extensive experience and expertise in all of these areas as well as implementation of large scale development of CBM projects.

Several factors, over which we have little or no control, could impact our future economic success. These factors include natural gas prices, limitations imposed by the terms and conditions of our lease agreements, possible court rulings concerning our property interests in CBM, availability of drilling rigs, operating costs, and environmental and other regulatory matters. In our planning process, we have attempted to address these issues by:

- negotiating to obtain leases that grant us the broadest possible rights to CBM for any given tract of land;
- conducting ongoing title reviews of existing mineral interests;
- where possible, negotiating and utilizing multiple service companies in order to increase competition and minimize the risk of disruptions caused by the loss of any one service provider; and
- attempting to create a low cost structure in order to reduce our vulnerability to many of these factors.

Critical Accounting Policies

Critical Accounting Policies and Estimates

Our consolidated financial statements and accompanying notes have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires our management to make estimates, judgments and assumptions that affect reported amounts of assets, liabilities, revenues and expenses. On an ongoing basis, we evaluate the accounting policies and estimates that we use to prepare financial statements. We base our estimates on historical experience and assumptions believed to be reasonable under current facts and circumstances. Actual amounts and results could differ from these estimates used by management.

Certain accounting policies that require significant management estimates and are deemed a critical component of our results of operations or financial position are discussed below. Our management reviews our critical accounting policies with the Audit Committee of our Board of Directors.

Accounting for CBM Projects

We follow the full cost method of accounting for our CBM properties. Under this method, all costs associated with the acquisition of, exploration for and development of our CBM reserves are capitalized in cost centers on a country-by-country basis (currently we have one cost center, the United States). Such costs include lease acquisition costs, geological and geophysical studies, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells, and overhead expenses directly related to these activities. Internal costs associated with our CBM activities that are not directly attributable to acquisition, exploration or development activities are expensed as incurred.

Unproved CBM properties and major development projects are excluded from amortization until a determination of whether proved reserves can be assigned to the properties or impairment occurs. Unproved properties are assessed at least annually to ascertain whether an impairment has occurred. Sales or dispositions of properties are credited to their respective cost centers and a gain or loss is recognized when all the properties in a cost center have been disposed of, unless such sale or disposition significantly alters the relationship between capitalized costs and proved reserves attributable to the cost center.

Capitalized costs of proved CBM properties, including estimated future costs to develop the reserves and estimated abandonment cost, net of salvage, are amortized on the units-of-production method using estimates of proved reserves.

A ceiling test is applied to each cost center by comparing the net capitalized costs, less related deferred income taxes, to the estimated future net revenues from production of proved reserves, discounted at 10%, plus the costs of unproved properties net of impairment. Any excess capitalized costs are written-off in the current year. The calculation of future net revenues is based upon prices, costs and regulations in effect at each year end.

In general, we determine if an unproved property is impaired if one or more of the following conditions exist:

- there are no firm plans for further drilling on the unproved property;
- negative results were obtained from studies of the unproved property;
- negative results were obtained from studies conducted in the vicinity of the unproved property; or
- the remaining term of the unproved property does not allow sufficient time for further studies or drilling.

Our estimate of proved reserves is based on the quantities of gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Our reserve estimates and the projected cash flows are derived from a report prepared by an independent engineering firm, in accordance with SEC guidelines, based in part on data provided by us. The accuracy of our reserve estimates depends in part on the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates.

Share-Based Payment

Prior to December 13, 2005, we had a stock-based compensation plan (the Incentive Stock Option Plan) under which stock options were issued to directors, officers, employees and consultants as determined by the Board of Directors and subject to the provisions of the Incentive Stock Option Plan. The Incentive Stock Option Plan permitted options to be issued with exercise prices at a discount to the market price of our common shares on the day prior to the date of grant. However, the majority of all stock options issued under the Incentive Stock Option Plan were issued with exercise prices equal to the quoted market price of the stock on the date of grant. Options granted under the Incentive Stock Option Plan vested immediately and were exercisable over a period not exceeding five years

On December 13, 2005, our shareholders approved the 2005 Omnibus Stock Plan (the Omnibus Stock Plan) and it became effective on that date. The Omnibus Stock Plan replaces the Incentive Stock Option Plan under which stock options were previously granted. The Omnibus Stock Plan is administered by the Compensation Committee of the

Board of Directors (the Committee) and will remain in effect for five years. All of our employees and directors, and any of our consultants or agents designated by the Committee, are eligible to participate in the Omnibus Stock Plan. The Committee has authority to: grant awards; select the participants who will receive awards; determine the terms, conditions, vesting periods and restrictions applicable to the awards; determine how the exercise price is to be paid; modify or replace outstanding awards within the limits of the Omnibus Stock Plan; accelerate the date on which awards become exercisable; waive the restrictions and conditions applicable to awards; and establish rules governing the Omnibus Stock Plan. No stock options have been issued under the Omnibus Stock

Plan. During the current fiscal year, the Committee granted stock awards under the Omnibus Stock Plan in the form of restricted and unrestricted stock to our employees and directors.

In December 2004, the FASB issued SFAS No. 123(R), Share-Based Payment. This Statement revises SFAS No. 123, Accounting for Stock-Based Compensation and supersedes APB Opinion No. 25, Accounting for Stock Issued to Employees. SFAS No. 123(R) focuses primarily on the accounting for transactions in which an entity obtains employee services in share-based payment transactions. The key provision of SFAS No. 123(R) requires companies to record share-based payment transactions as compensation expense at fair market value based on the grant-date fair value of those awards. Previously under SFAS 123, companies had the option of either recording expense based on the fair value of stock options granted or continuing to account for stock-based compensation using the intrinsic value method prescribed by APB No. 25.

We adopted SFAS No. 123(R), using the modified-prospective method, effective August 1, 2005. Since August 1, 2001, we have followed the fair value provisions of SFAS 123 and have recorded all share-based payment transactions as compensation expense at fair market value based on the grant-date fair value of those awards. In addition, all stock options granted prior to the adoption of SFAS No. 123(R) vested immediately on the date of grant and, thus, there was no unvested portion of previous stock option grants that vested during fiscal year 2006. Therefore, SFAS 123(R) had no impact on our consolidated financial position or results of operations for fiscal year 2006. We use the Black-Scholes formula to estimate the fair value of stock options granted.

Revenue Recognition

All revenue from gas sales is recognized after the gas is produced and delivery takes place. We currently sell all of our gas to one gas marketing company, Atmos Energy Marketing, LLC.

Asset Retirement Obligations

We follow Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. SFAS No. 143 requires us to record the fair value of an asset retirement obligation as a liability in the period in which it is incurred, if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement costs is capitalized as part of the carrying amount of the associated long-lived asset. Amortization of the capitalized asset retirement cost is determined on a units-of-production method. Accretion of the asset retirement obligation is recognized over time until the obligation is settled. The future cash outflows associated with settling the asset retirement obligations accrued on the accompanying consolidated balance sheets are excluded from the ceiling test calculation. Our asset retirement obligations relate to the plugging of wells upon exhaustion of gas reserves.

The fair value of the liability associated with these retirement obligations is determined using significant assumptions, including current estimates of the plugging costs, annual inflation of these costs, the productive life of the wells and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to the carrying amount of the related long-lived asset, resulting in prospective changes to depreciation, depletion and amortization expense and accretion. Because of the subjectivity of assumptions and the relatively long life of our wells, the costs to ultimately retire these assets may vary significantly from previous estimates.

Deferred Income Taxes

We operate in two tax jurisdictions, the United States and Canada. Primarily as a result of the net losses that we have generated, we have generated deferred tax benefits available for tax purposes to offset net income in future periods. However, a full valuation allowance has been recorded against all deferred tax assets in Canada as we historically have had no income generating operations in Canada. We have recorded tax benefits in the United States for our fiscal years ending July 31, 2005 and 2004. These benefits partially offset a previously recorded deferred tax liability.

Impact of Recently Issued Accounting Standards Not Yet Adopted

In June 2006, the FASB issued FASB Interpretation Number 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109. This Interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, Accounting for Income Taxes. This Interpretation is effective for fiscal years beginning after December 15, 2006. We are currently assessing the effect of this Interpretation, if any, on our consolidated financial statements.

Results of Operations

Year Ended July 31, 2006 Compared to Year Ended July 31, 2005

The following table presents our unaudited financial data for fiscal year 2006 compared to fiscal year 2005:

	Fiscal Year Ended July 31,		**Dollar**	**%**
	2006	**2005**	**Variance**	**Change**
Revenues:				
Gas sales	$ 1,126,477	$ 117,835	$ 1,008,642	856%
Expenses:				
Lease operating expense	970,791	307,178	663,613	216%
General and administrative expense	6,576,131	5,805,121	771,010	13%
Depreciation, depletion and amortization	570,303	260,141	310,162	119%
	8,117,225	6,372,440	1,744,785	27%
Other income (expenses):				
Interest income	941,351	123,219	818,132	664%
Interest expense	(22,405)	(24,820)	2,415	10%
Other income (expense)	(2,764,443)	35,385	(2,799,828)	(7,912)%
	(1,845,497)	133,784	(1,979,281)	(1,479)%
Loss before income taxes	(8,836,245)	(6,120,821)	(2,715,424)	(44)%
Deferred income tax benefit		724,470	(724,470)	(100)%
Net loss	$ (8,836,245)	$ (5,396,351)	$ (3,439,894)	(64)%

Revenue Revenue from gas sales increased $1,008,642 in fiscal year 2006, an increase of 856% over fiscal year 2005. We realized our first revenues from the sale of CBM in January 2005. Net sales of gas (net of royalties) were 135,118 Mcf for fiscal year 2006 compared to 17,885 Mcf for fiscal year 2005. Our average realized selling price per Mcf increased to $8.34 in fiscal year 2006 compared to $6.59 in fiscal year 2005.

Lease operating expense Lease operating expense increased $663,613 in fiscal year 2006, an increase of 216% over fiscal year 2005. Lease operating expenses represent production expenses, consisting primarily of repairs and maintenance, fuel and electricity, equipment rental and other overhead expenses related to producing wells. The increase is primarily due to the increase in producing wells and the related increase in gas production.

General and administrative expense General and administrative expense consisted of the following for fiscal year 2006 and 2005:

	Fiscal Year Ended July 31, 2006	Fiscal Year Ended July 31, 2005	Dollar Variance	% Change
Salaries and benefits	$ 2,027,707	$ 894,141	$ 1,133,566	127%
Stock-based compensation	1,377,440	3,344,738	(1,967,298)	(59)%
Professional and regulatory	2,637,916	1,183,402	1,454,514	1,229%
Other	533,068	382,840	150,228	39%
Total general and administrative expense	$ 6,576,131	$ 5,805,121	$ 771,010	13%

Salaries and benefits increased $1,133,566 in fiscal year 2006, an increase of 127% over fiscal year 2005. The increase was primarily the result of (i) hiring additional personnel to support our growth throughout fiscal years 2005 and 2006, including a Senior Vice President of Operations (April 2006), a Chief Financial Officer (January 2005) and a Controller (February 2005); (ii) executive bonuses paid during fiscal year 2006; and (iii) general salary increases. We had 16 full-time employees at July 31, 2006 compared to 10 full-time employees at July 31, 2005. In addition, we expanded our technical team, adding three engineers and a geologist during the first quarter of fiscal year 2007, which will result in additional annualized salaries of $600,000 beginning in fiscal year 2007.

Stock-based compensation expense decreased $1,967,298 in fiscal year 2006, a decrease of 59% from fiscal year 2005. During fiscal year 2006, 495,000 stock options were granted, whereas 4,276,056 stock options were granted to various employees and directors in fiscal year 2005. During fiscal year 2006, we issued stock-based awards to employees and directors as follows: (i) 300,000 unrestricted common shares and 300,000 restricted common shares to our newly hired Senior Vice President of Operations; (ii) 140,000 unrestricted common shares to a newly appointed director; and (iii) 495,000 stock options to various employees and directors. We also replaced 2,025,000 stock options with 2,025,000 restricted common shares for key employees and directors during fiscal year 2006. The expense related to the issuance of unrestricted common shares and stock options was fully recognized in fiscal year 2006. A portion of the expense related to the issuance of restricted common shares, representing the vested portion of such shares, was also recognized in fiscal year 2006. We expect to continue our practice of granting share-based awards to employees in order to attract and retain qualified individuals. Such awards may be in the form of stock options, unrestricted common shares, restricted common shares or other share-based awards. However, we most likely will increase our use of restricted stock awards as the preferred method of share-based compensation in lieu of granting stock options, which was our predominant practice in prior years.

Professional and regulatory fees increased $1,454,514 in fiscal year 2006, an increase of 1,229% over fiscal year 2005. The increase was primarily the result of increased legal fees incurred in connection with our lawsuit against Colt LLC and higher costs associated with being a public company in the United States. Specifically, the increase resulted from the following:

Additional legal fees incurred in connection with Colt LLC lawsuit	$	582,528
Increase in executive placement fees		293,325
Increase in printing costs of SEC filings		258,809
Increase in insurance costs		220,936
Increase in AMEX listing fees		115,000
Increase in fees related to accounting, auditing and tax services		68,030
Increase in legal fees incurred in connection with SEC filings		69,920
Decrease in legal fees incurred in connection with surface disputes		(293,305)
Net increase in other professional and regulatory fees		139,271
Total increase over corresponding period in the preceding year	$	1,454,514

Other general and administrative expenses increased $150,228, an increase of 39% over fiscal year 2005, primarily as a result of increased office and travel-related expenses.

Depreciation, depletion and amortization expense Depreciation, depletion and amortization expense (DD&A) increased $310,162 in fiscal year 2006, an increase of 119% over fiscal year 2005. We compute DD&A on capitalized drilling costs and gas collection equipment using the units-of-production method based on estimates of proved reserves, and on all other property and equipment using the straight-line method based on estimated useful lives ranging from three to 10 years. The increase is primarily due to the increase in capitalized development costs and an increase in production over fiscal year 2005. Additionally, depreciation expense increased due to additions to other support equipment.

Interest income Interest income increased $818,132, an increase of 664% over fiscal year 2005 due to significantly higher average cash balances during fiscal year 2006. The higher cash balances are the result of the net proceeds of $27,883,954 we received in September 2005 related to the private placement of our common shares. We invest our excess cash in overnight sweep accounts and high-grade commercial paper with maturities of 30 days or less.

Other income (expense) Other income (expense) decreased $2,799,828, or 7,912%, in fiscal year 2006, primarily due to recognizing $2,951,608 of other expense related to settling our dispute with Colt LLC, partially offset by other income of $127,416 related to the sale of our investment in HCM and an increase in distributions from HCM of $44,837 during fiscal year 2006. We believe that these settlement costs will be more than recouped through reduced royalty payments in future years.

Deferred income tax benefit Deferred income tax benefit decreased $724,470 in fiscal year 2006, a decrease of 100% over fiscal year 2005. We recorded a tax benefit in the United States in fiscal year 2005 to partially offset a net recorded deferred tax liability at July 31, 2005. However, no tax benefit was recognized for fiscal year 2006, as we had no net deferred tax liability to offset.

Year Ended July 31, 2005 Compared to Year Ended July 31, 2004

The following table presents our unaudited financial data for fiscal year 2005 compared to fiscal year 2004:

	Fiscal Year Ended July 31,		**Dollar**	**%**
	2005	**2004**	**Variance**	**Change**
Revenues:				
Gas sales	$ 117,835	$	$ 117,835	100%
Expenses:				
Lease operating expense	307,178		307,178	100%
General and administrative expense	5,805,121	1,000,107	4,805,014	480%
Depreciation, depletion and amortization	260,141	80,417	179,724	223%
	6,372,440	1,080,524	5,291,916	490%
Other income (expenses):				
Interest income	123,219	2,008	121,211	6,036%
Interest expense	(24,820)	(15,165)	(9,655)	(64)%
Other income	35,385	2,454	32,931	1,342%
	133,784	(10,703)	144,487	1,350%
Loss before income taxes	(6,120,821)	(1,091,227)	(5,029,594)	(461)%
Deferred income tax benefit	724,470	298,111	426,359	143%
Net loss	$ (5,396,351)	$ (793,116)	$ (4,603,235)	(580)%

Revenue We realized our first revenues from the sale of CBM in January 2005. Sales of CBM generated revenues of $117,835 during fiscal year 2005 (all in the period of January through July 2005) compared to $0 sales during fiscal year 2004. All of our productive wells during fiscal year 2005 were located at our Southern Illinois Basin Project.

Lease operating expense Lease operating expenses represent production expenses, consisting primarily of repairs and maintenance, fuel and electricity, equipment rental and other overhead expenses related to producing wells. We commenced production toward the end of January 2005 and, thus, incurred no lease operating expense during fiscal year 2004.

General and administrative expense General and administrative expense consisted of the following for fiscal years 2005 and 2004:

	Fiscal Year Ended July 31, 2005	2004	Dollar Variance	% Change
Salaries and benefits	$ 894,141	$ 418,701	$ 475,440	114%
Stock-based compensation	3,344,738	193,796	3,150,942	1,626%
Professional and regulatory	1,183,402	98,458	1,084,944	1,102%
Other	382,840	289,152	93,688	32%
Total general and administrative expense	$ 5,805,121	$ 1,000,107	$ 4,805,014	480%

Salaries and benefits increased $475,440 in fiscal year 2005, an increase of 114% over fiscal year 2004. The increase was primarily the result of bonuses paid to various employees, hiring a Vice President of Field Operations, a Chief Financial Officer and a Controller, and general salary increases.

Stock-based compensation increased $3,150,942 in fiscal year 2005, an increase of 1,626% over fiscal year 2004. The increase resulted primarily from the granting of additional options to various key employees and directors of the company and the general increase in our stock price. During fiscal year 2005, we granted options to purchase 4,276,056 common shares that were valued at $3,344,738. This compares with the options to purchase 475,000 common shares that were granted during fiscal year 2004 and were valued at $193,796. The award of these options was consistent with our belief that it is necessary to provide this form of compensation for us to attract and retain qualified individuals.

Professional and regulatory fees increased $1,084,944 in fiscal year 2005, an increase of 1,102% over fiscal year 2004. The increase resulted from the following:

Additional legal fees incurred in connection with surface disputes	$ 303,305
Increase in fees related to accounting, auditing and tax services	193,046
Increase in legal fees incurred in connection with SEC filings	175,567
Increase in fees related to general corporate legal and professional advice	150,522
Increase in fees related to outside investor relations services	141,757
Net increase in other professional fees	120,747
Total increase over corresponding period in the preceding year	$ 1,084,944

Other general and administrative expenses increased $93,688 in fiscal year 2005, an increase of 32% over fiscal year 2004. The increase resulted primarily from additional costs incurred in opening our headquarters office in Solon, Ohio during fiscal year 2005.

Depreciation, depletion and amortization expense Depreciation, depletion and amortization expense (DD&A) increased $179,724 in fiscal year 2005, an increase of 223% over fiscal year 2004. We compute DD&A on capitalized drilling costs and gas collection equipment using the units-of-production method based on estimates of proved reserves, and on all other property and equipment using the straight-line method based on estimated useful lives ranging from three to 10 years. The increase is primarily due to the fact that we had no production in fiscal year 2004. Additionally, depreciation expense increased due to additions to other support equipment.

Interest income Interest income increased $121,211 in fiscal year 2005, an increase of 6,036% over fiscal year 2004 due to significantly higher average cash balances during fiscal year 2005.

Other income Other income increased $32,931 in fiscal year 2005, an increase of 1,342% over fiscal year 2004. The increase is primarily due to us recognizing a gain of $42,276 on the sale of our remaining 432,000 shares of Pyng Technologies Corp., a TSX Venture listed public company, during fiscal year 2005.

Deferred income tax benefit The deferred income tax benefit increased $426,359 in fiscal year 2005, an increase of 143% over fiscal year 2004. The increase resulted primarily from the increase in our loss before income taxes. The effect of the increase in our loss before income taxes was partially offset by a decrease in the effective tax rate to 11.8% during fiscal year 2005, as compared to 27.3% in fiscal year 2004. The decrease in rate was primarily the result of an increase in stock-based compensation expense, which is non-deductible for U.S. tax purposes.

Liquidity and Capital Resources

Our primary source of liquidity historically has come from the sale of our common shares in private placements and the proceeds from the exercise of warrants and options to acquire our common shares. To date, we have not relied significantly on borrowing to finance our operations or provide cash. As of July 31, 2006, we had only $216,015 in long-term notes payable. From July 31, 2003 until July 31, 2006, we raised $43,198,616 from the sale of our common shares. Additionally, during that same period, we collected $6,728,810 as a result of the exercise of warrants and $2,042,280 as a result of the exercise of stock options. Our primary use of these funds has been the acquisition, exploration, testing and development of our CBM properties and rights.

We did not begin to generate revenues from CBM sales until January 2005. Revenues from CBM sales were $1,126,477 for fiscal year 2006 and $117,835 for fiscal year 2005. We expect revenue from the sale of our CBM to increase due to (i) increased production from existing wells as they proceed through the initial dewatering phase and (ii) additional production generated as a result of drilling additional wells. However, in view of our limited production history, we can provide no assurance that we will achieve a trend of increased production and CBM revenue in the future.

CBM wells typically must go through a lengthy dewatering phase before making any meaningful contribution to gas production. We estimate that a typical vertical well will require about 24 months to reach peak production. The impact on our cash position is that there will be a delay of up to 24 months between the time we initially invest in drilling and completing a well and the time when a typical well will begin to make a meaningful contribution to our cash from operations.

We had a cash balance of $19,279,015 at July 31, 2006, compared to $7,251,503 at July 31, 2005. The net increase in our cash balance is primarily due to the $27,883,954 of net proceeds we received from the sale of our common shares in a private placement that closed on September 26, 2005, $5,013,928 received as a result of the exercise of warrants during fiscal year 2006, and $382,239 received as a result of the exercise of stock options during fiscal year 2006. We raised an amount in the private placement we felt was required to fund our development plans through April 2006. However, because our drilling progress at our Southern Illinois Basin Project was slowed due to the dispute with one of the coal owners, we now believe our cash balance will be sufficient to fund the low end of our forecasted capital program through July 31, 2007. Our revenues and cash balances, however, will not likely be sufficient to fund the high end of our capital program for fiscal 2007 or our operations beyond that date. Therefore, we will likely need to raise additional financing in the near future. We currently do not have any specific plans to raise financing in support of our future operations. Although management has no specific plans in place to raise the additional capital necessary to fund our plan of operations and forecasted capital expenditures, management anticipates raising the additional required capital through a combination of additional stock sales, the issuance of debt securities, borrowing and/or entering into joint ventures.

Cash Used in Operating Activities

Net cash used in operating activities for fiscal year 2006 was $6,560,034. This compares with $2,474,443 net cash used in operating activities in the prior year. The increase in net cash used in operating activities resulted from the $3,000,000 paid to Colt LLC to settle a lawsuit and increased general and administrative expenses required to support the growth in the size of our projects in the Illinois Basin. Net cash used in operating activities for fiscal year 2004 was $906,849. Since July 31, 2003, we have substantially increased our exploration and operating activities, and therefore our personnel, in the Illinois Basin. Since we did not generate any CBM revenues until January 2005, the costs associated with the additional activities and personnel resulted in year-to-year increases in net cash used in operations.

Net cash used by operating activities is dependent on a number of factors over which we have little or no control. These factors include, but are not limited to:

- the price of, and demand for, natural gas;
- availability of drilling and service equipment and personnel;
- lease terms;
- availability of sufficient capital resources; and
- the accuracy of production estimates for current and future wells.

Cash Used in Investing Activities

Net cash used in investing activities for fiscal year 2006 was $14,517,293. This compares with $6,338,082 net cash used in investing activities in fiscal year 2005 and $1,787,382 net cash used in investing activities in fiscal year 2004. The increases in net cash used in investing activities during fiscal years 2005 and 2006 are primarily the result of increased exploration and development costs at our projects, the installation of a gas gathering system at our Southern Illinois Basin Project, and additions to vehicles and other equipment to support our growth in operations.

Cash Provided by Financing Activities

Net cash provided by financing activities for fiscal year 2006 was $33,104,839. This compares with $15,093,233 net cash provided by financing activities in fiscal year 2005 and $3,498,439 net cash provided by financing activities in fiscal year 2004. The increases in net cash provided by financing activities during fiscal years 2005 and 2006 are primarily the result of increased proceeds from common shares issued in private placements and from the exercise of stock options and warrants. We received net proceeds from common shares issued in private placements in the amount of $27,883,954 during fiscal year 2006, $12,074,106 during fiscal year 2005 and $3,240,556 during fiscal year 2004. In addition, we received aggregate proceeds from the exercise of stock options and warrants in the amounts of $5,396,167 during fiscal year 2006, $3,331,887 during fiscal year 2005 and $43,036 during fiscal year 2004. We continue to pay down our long-term notes, making payments of $175,282 in fiscal year 2006, $42,320 in fiscal year 2005 and $26,014 in fiscal year 2004. Our long-term notes payable (including current maturities) decreased from $549,822 at July 31, 2005 to $216,015 at July 31, 2006. We expect to continue to reduce our long-term notes payable by making scheduled principal payments of $140,866 in fiscal year 2007.

Capital Expenditure Plan

We have no contractual commitments for capital expenditures. However, our plan anticipates that over the year ending July 31, 2007, we will spend approximately $12.0 million to $30.0 million on capital expenditures. These amounts correspond to drilling 58 wells at the low end of the range and 123 wells at the upper end. These amounts include installing a gathering system and processing yard to handle the anticipated production from our 10-well pilot program and additional pilot wells and/or production wells at our three current projects. In addition to our drilling program, we expect to pursue the acquisition of additional CBM rights during the fiscal year. We expect that this capital expenditure program and our other cash requirements will be funded by our cash balance, which as of October 25, 2006 is approximately $15.1 million, and cash raised through the sale of debt securities, equity securities, borrowings and/or joint ventures. Although we are currently evaluating the best methods of raising these funds, we can provide no assurance that we will be able to raise the necessary funds.

Contractual Obligations

	Payments Due by Period				
	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years	Total
Contractual Obligations As of July 31, 2006:					
Long-term debt	$ 148,601	$ 63,674	$ 17,840	$	$ 230,115
Equipment leases	82,875	13,813			96,688
Asset retirement obligations	9,600			70,754	80,354
Other leases(1)	136,266	197,272	29,784	262,557	625,879
Total	$ 377,342	$ 274,759	$ 47,624	$ 333,311	$ 1,033,036

(1) These amounts do not include annual minimum royalty payments required to hold mineral lease and farm-out agreements. Although we are not obligated to make these payments under existing mineral leases and farm-out agreements, these payments are required to maintain individual lease/farm-out agreements after the expiration of the initial terms of the lease/farm-out agreements. The lease/farm-out agreements in existence as of October 25, 2006 expire at various times beginning in November 2007. If we were to pay the total minimum royalty payments due under all lease/farm-out agreements in existence as of October 25, 2006, the amount would initially total approximately $100,000 annually and could increase to as much as $220,000 annually.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of July 31, 2006.

Cautionary Statement Concerning Forward-Looking Statements

Some of the statements contained in this prospectus supplement and other materials we file with the SEC, or in other written or oral statements made or to be made by us, other than statements of historical fact are forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements give our current expectations or forecasts of future events. Statements containing the words believes, anticipates, expects, intends, plans, predict, strategy, budget, project, potential, should, may, might, continue and words are used to identify forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements, or the conditions in our industry, on our properties or in the Illinois Basin to be materially different from any future results, performance, achievements or conditions expressed or implied by such forward-looking statements. Some of the factors that could cause actual results or conditions to differ materially from our expectations include the factors discussed in the 125483 Prospectus and the 130122 Prospectus under the heading Risk Factors and elsewhere.

Given these uncertainties, you should not place undue reliance on such forward-looking statements. Except as otherwise required by applicable law, we undertake no obligation to publicly update or revise any forward-looking statements, the risk factors or other information described in this prospectus supplement, the 125483 Prospectus or the 130122 Prospectus, whether as a result of new information, future events, changed circumstances or any other reason after the date of such forward-looking statements.

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Business

The disclosure presented below replaces the disclosure presented under the subsections titled CBM Acreage Rights and Legal Proceedings and supplements the disclosure presented under the subsection titled Plan of Operations for the 12-Month Period Ending April 30, 2007 under the Business section in the 125483 Prospectus and the 130122 Prospectus.

CBM Acreage Rights

As of July 31, 2006, our CBM acreage rights, controlled through lease, option and farm-out agreements and ownership of a CBM estate, include the following:

Project	Developed Acres	Undeveloped Acres	Total Acres(1)
Southern Illinois Basin Project(2)	5,532	4,468	10,000
Northern Illinois Basin Project	0	353,531	353,531
Western Illinois Basin Project	0	135,948	135,948
Total	5,532	493,947	499,479

(1) Because we are the exclusive owner of the CBM rights under each of our lease, option and farm-out agreements, our acreage totals reflect both gross and net acres.

(2) We acquired ownership of the CBM estate covering 10,000 acres in our Southern Illinois Basin Project in a settlement with our former lessor, which is the owner of the coal rights.

Under the terms of the lease and option agreements pursuant to which we have acquired nearly all of our CBM rights, we are entitled to all of the CBM rights held by our lessors in the counties covered by these agreements. However, we face a number of uncertainties regarding what rights our lessors hold.

The issue of who owns CBM gas, as between the coal rights owner and the oil and gas rights owner, is uncertain in Illinois. Although the appellate court in Illinois for the district where most of our acreage rights are situated has ruled that CBM gas is owned by the coal rights owner, the issue has not been addressed by the highest court in Illinois. We believe, based on advice from legal counsel, that under Illinois law ownership will ultimately be found to lie with the coal rights owner. Based on this advice, we generally secure CBM rights from the coal owners. Some of the lessors from which we have acquired CBM rights may hold both the coal rights and the oil and gas rights for the applicable properties, but in some cases it is not certain that these lessors also hold the oil and gas rights. If any litigation in Illinois concludes that CBM rights lie with the oil and gas owner, we could lose some of our CBM rights.

In addition, in some cases the extent of the coal and/or oil and gas rights held by our lessors is uncertain. We conducted no title or deed examinations prior to executing our lease and option agreements, and our lessors made no warranties as to the acreage or rights covered by the agreements. Although we have now conducted title and deed examinations covering much of the CBM properties under our leases, these examinations are ongoing at all of our projects. There can be no assurance that our rights under our lease and option agreements include all of the acreage and rights identified in the agreements until title examinations on all of the underlying properties have been completed.

We have been subject to legal complaints regarding the extent of the surface rights that derive from our CBM rights. On occasion, the owners of properties that are adjacent to our drilling locations have challenged our right to cross their property in accessing our drilling locations and our right to lay gas and water flow lines across their property. The extent of our rights in respect of these issues is uncertain in Illinois. If disputes regarding our surface rights are not resolved in our favor, we may be required to acquire surface rights or access our drilling locations and lay gas and water flow lines in inefficient ways, which would cause us to incur increased operating costs. In addition, we could incur significant costs in legal disputes over our surface rights. During our fiscal year ended July 31, 2005 we incurred approximately $303,000 in legal fees in connection with legal disputes over surface rights, and during our fiscal year ended July 31, 2006 we incurred approximately $10,000 in legal fees in connection with such disputes. If for any reason these operating or legal costs increase significantly, our financial performance will suffer.

Southern Illinois Basin Project

Our CBM rights in the Southern Illinois Basin Project cover 10,000 acres in the southern part of the Illinois Basin. We hold our CBM rights on this acreage pursuant to a purchase agreement under which we acquired the CBM estate in a settlement with our former lessor, the owner of the coal rights. Under the terms of the deed covering this acreage, our right to drill for and produce CBM takes precedence over coal mining operations for as long as CBM is being produced from the acreage. However, the owner of the coal rights has the right to acquire any CBM wells located in these 10,000 acres. If the coal rights owner exercises this option, it will be required to (i) immediately plug any such well so acquired and (ii) pay the fair market value (as established by a mutually agreed upon expert) of such well.

We are currently paying two overriding royalties of 3% and 4% on our production at this project, which are calculated based on 43.35% of our gross revenues.

We commenced sales of gas from our initial pilot production wells on this project in January 2005. As of July 31, 2006, we have drilled 108 wells at this project. These wells consist of 86 productive wells, 14 shut-in wells, of which eight are scheduled to be plugged in fiscal year 2007 (as a result of the Colt LLC settlement), four plugged wells, one disposal well and three wells that have been drilled but are not yet in production. Most of the productive wells drilled at this project were initially completed in a limited number of seams, intentionally excluding other seams. Our intention when we drilled these wells was to gather as much geological information as we could about CBM and dewatering characteristics of individual coal seams. During our 2006 fiscal year we went back and completed additional seams in most of these wells to begin dewatering and producing CBM from the additional seams penetrated by these wells. During fiscal year 2007, we will determine whether it is beneficial to complete additional seams in the remaining wells.

Northern Illinois Basin Project

Our CBM rights in the Northern Illinois Basin Project cover 353,531 acres in Montgomery, Shelby, Christian, Fayette and Macoupin Counties in Illinois, which are located in the north central part of the Illinois Basin. We hold our CBM rights on this acreage pursuant to mineral leases, an option to acquire a mineral lease and a farm-out agreement.

We have entered into a lease agreement with Montgomery County covering 120,951 acres of CBM rights in Montgomery County, Illinois. The lease agreement extends until November 27, 2010. After the initial term of the agreement, we can continue to hold the lease as long as we are producing CBM from the covered acreage. Under the lease agreement, we will be required to pay royalties to the lessor equal to 12.5% of our gross proceeds from the sale of CBM produced from the covered acreage.

We have also entered into a lease agreement with Shelby County covering 63,250 acres of CBM rights in Shelby County, Illinois. This lease agreement extends until November 12, 2008. After the initial term of the agreement, we can continue to hold the lease as long as we are producing CBM from the covered acreage, with each productive vertical well holding 320 acres and each productive horizontal well holding 1,920 acres. We are required to pay royalties to the lessor equal to 12.5% of our gross proceeds from the sale of CBM produced from the covered acreage.

We have also entered into a lease agreement with IEC (Montgomery), LLC covering 102,000 acres of CBM rights in Christian, Fayette, Montgomery and Shelby Counties in Illinois. The lease agreement extends until April 26, 2026. After the initial term of the agreement, we can continue to hold the lease as to each acreage block where we are producing CBM in commercial quantities. We are required to pay royalties to the lessor on our gross proceeds from the sale of CBM produced from the covered acreage at rates ranging up to 12.5%.

We have also entered into a lease agreement with Christian Coal Holdings, LLC covering 12,044 acres of CBM rights in Christian and Montgomery Counties in Illinois. The lease agreement extends until April 26, 2026. After the initial term of the agreement, we can continue to hold the lease as to each acreage block where we are producing

CBM in commercial quantities. We are required to pay royalties to the lessor on our gross proceeds from the sale of CBM produced from the covered acreage at a rate of 12.5%.

We also hold an option from Christian County to lease 14,033 acres of CBM rights in Christian County, Illinois. The option extends until January 20, 2007. The lease agreement underlying the option will extend for a period of five years from the date we exercise the option. After the initial term of the agreement, we can continue to hold the lease as long as we are producing CBM from the covered acreage. Under the lease agreement, we will be required to pay royalties to the lessor equal to 12.5% of our gross proceeds from the sale of CBM produced from the covered acreage.

Under the lease agreements with Montgomery and Shelby Counties and the lease agreement underlying the option agreement with Christian County, our right to drill for and produce CBM is expressly subject to the mining of coal on the covered acreage. We may not interfere with any existing coal mining operations and, under certain circumstances, may be required to cease drilling in locations where coal mining operations will be undertaken.

Under the lease agreements with IEC (Montgomery), LLC and Christian Coal Holdings, LLC, any drilling operations that we set up can be displaced by coal mining operations. However, the lessor is required to provide us with a mine plan for the leased acreage indicating the acreage blocks that the lessor plans to mine and the order of priority for the acreage blocks that it plans to mine. If the lessor displaces a well ahead of the schedule outlined in the mine plan, the lessor may be required to reimburse us for the cost of plugging the well and, depending on how long the well has been in production and the cumulative gross income generated by the well, the value of the CBM that could be recovered from the well in the remainder of an eight-year term.

Also included in the Northern Illinois Basin Project are 41,253 acres of CBM rights in Macoupin County, Illinois, which we can earn under a farm-out agreement with Addington Exploration, LLC, as described below.

As of July 31, 2006, we had just recently completed drilling of a 10-well pilot program at this project, and all wells were in the initial stages of dewatering as of that date. As of the same date, we have drilled three test wells at this project. In addition, we intend to drill two additional test wells at this project during the first quarter of 2007.

Western Illinois Basin Project

Our CBM rights in the Western Illinois Basin Project cover 135,948 acres in Clinton, Washington, Marion and Perry Counties in Illinois, which are located in the northwestern part of the Illinois Basin. We hold our CBM rights on this acreage pursuant to mineral leases, an option to acquire a mineral lease and a farm-out agreement.

We have entered into a lease agreement with Clinton County covering 55,900 acres of CBM rights in Clinton County, Illinois. The lease agreement extends until October 24, 2010. After the initial term of the agreement, we can continue to hold the lease as long as we are producing CBM from the covered acreage. We are required to pay royalties to the lessor equal to 12.5% of our gross proceeds from the sale of CBM produced from the covered acreage.

We have also entered into a lease agreement with Washington County covering 39,169 acres of CBM rights in Washington County, Illinois. The lease agreement extends until September 9, 2011. After the initial term of the agreement, we can continue to hold the lease as long as we are producing CBM from the covered acreage, with each productive vertical well holding 320 acres and each productive horizontal well holding 1,920 acres. We are required to pay royalties to the lessor from our gross proceeds from the sale of CBM produced from the covered acreage. The royalty is equal to 12.5% or 6.25% of our gross proceeds, depending on whether it is determined that Washington County s CBM rights, if any, are derived from coal rights or oil and gas rights.

We also hold an option from Marion County to lease 17,882 acres of CBM rights in Marion County, Illinois. The option extends until June 8, 2007. The lease agreement underlying the option will extend for a period of five years from the date we exercise the option. After the initial term of the agreement, we can continue to hold the lease as long as we are producing CBM from the covered acreage. Under the lease agreement, we will be required to pay royalties to the lessor equal to 12.5% of our gross proceeds from the sale of CBM produced from the covered acreage. If we do not commence exploration of CBM within one year from the commencement of the lease, we will be required to pay advance royalties to the lessor equal to $8,941 for each one-year period that we delay commencing exploration. Any payment of advance royalties can be credited against royalties that may later become payable to the lessor from our production of CBM.

Under the lease agreement with Washington County and the lease agreement underlying the option agreement with Marion County, our right to drill for and produce CBM is expressly subject to the mining of coal on the covered acreage. We may not interfere with any existing coal mining operations and, under certain circumstances, may be required to cease drilling in locations where coal mining operations will be undertaken. Under the lease agreement with Clinton County, coal mining rights granted to third parties do not take precedence over our CBM operations.

Also included in the Western Illinois Basin Project are 22,997 acres in Perry County, Illinois, which we can earn under a farm-out agreement with Addington Exploration, LLC, as described below.

As of July 31, 2006, we have drilled two wells at the Western Illinois Basin Project that have not yet been completed and from which we are still gathering and evaluating test data. We intend to drill three test wells at this project during the first quarter of fiscal 2007.

Farm-out Agreement with Addington Exploration, LLC

We have entered into a farm-out agreement with Addington Exploration, LLC covering 41,253 acres of CBM rights in Macoupin County, Illinois and 22,997 acres of CBM rights in Perry County, Illinois that Addington controls pursuant to coal seam gas leases. The farm-out agreement provides for an initial 36-month evaluation period, during which we may test and evaluate the covered properties. The 36-month evaluation period can be extended by us on unearned acreage through the payment of a fee equal to $0.50 per acre, increasing over five years to $2.50 per acre. For each vertical and horizontal well that we place into production during the term of the agreement, Addington will assign to us its CBM rights covering the surrounding 160 acres penetrated by one of our wells.

We are required to pay Addington a royalty equal to 3% of our proceeds from the sale of CBM produced from the covered acreage. In addition, we must pay royalties totaling 12.5% to the lessors under the coal seam gas leases underlying this farm-out agreement.

Technical Services Agreement with BHP Billiton

Our Technical Services Agreement with BHP Petroleum (Exploration) Inc., a wholly owned subsidiary of BHP Billiton, expired at the end of its term on September 30, 2006, and BHP did not exercise its right to extend the agreement. The right of first refusal to acquire us that was granted to BHP under the Technical Services Agreement lapsed as of the expiration date of the agreement, although the 4.0 million stock appreciation rights that we granted to BHP, which may be exercised by BHP only in connection with an acquisition of us, continue in effect until March 30, 2007.

Status of CBM Operations

The following table summarizes the status of wells we have drilled as of July 31, 2006:

Project	Productive Wells	Drilled Not Yet Completed(1)	Nonproductive Wells Shut-in(2)	Plugged	Disposal	Total
Southern Illinois Basin Project	86	3	14	4	1	108
Northern Illinois Basin Project		13		1	1	15
Western Illinois Basin Project		2				2
Total	86	18	14	5	2	125

(1) Wells drilled not yet completed includes our recently completed drilling of a 10-well pilot program and three test wells at the Northern Illinois Basin Project, two test wells at our Western Illinois Basin Project and three wells drilled at our Southern Illinois Basin Project in late fiscal year 2006 that were completed in early fiscal year 2007 and became productive wells.

(2) Shut-in wells include eight wells that will be plugged during fiscal year 2007 in connection with our settlement agreement with Colt LLC. Of these eight wells to be plugged, Colt LLC has agreed to plug four wells at their expense and we will be responsible for plugging the remaining four wells.

The following table sets forth our drilling activities over the last three fiscal years:

	Fiscal Years Ended July 31, 2006	2005	2004
Exploratory Wells(1):			
Productive(2)	10		
Nonproductive(3)	4	3	
Total	14	3	
Development Wells(1):			
Productive(2)	49	37	
Nonproductive(3)	5	17	
Total	54	54	
Total Wells:			
Productive(2)	59	37	
Nonproductive(3)	9	20	
Total	68	57	

(1) An exploratory well is a well drilled either in search of a new, as yet undiscovered CBM reservoir or to greatly extend the known limits of a previously discovered reservoir. A development well is a well drilled within the presently proved productive area of a CBM reservoir, as indicated by reasonable interpretation of available data, with the objective of completing in that reservoir.

(2) A productive well is an exploratory or development well that has been completed and is tied into our gas and/or dewatering system. A productive well may produce only water for a period of time before gas begins to flow through the gas gathering system.

(3) A nonproductive well is an exploratory or development well that is not currently a producing well.

As of July 31, 2006, all of the wells that we have drilled are vertical wells. We estimate that a typical vertical well will require about 24 months to reach peak production. Most of the productive wells were completed in a limited number of seams, intentionally excluding other seams. Our intention when we drilled these wells was to gather as much geological information as we could about CBM and dewatering characteristics of individual coal seams. During our 2006 fiscal year we went back and completed additional seams in most of these wells to begin dewatering and producing CBM from the additional seams penetrated by these wells. During fiscal year 2007, we will determine whether it is beneficial to complete additional seams in the remaining wells. We began selling gas from our first productive wells in January 2005. As of July 31, 2006, we believe that most of our productive wells have not yet reached peak production. Although we have drilled wells on only a relatively small part of our acreage, we have not to date determined that any well we have drilled is a dry hole.

Production and Sales

The following table sets forth our net sales volume for the periods indicated.

	Twelve Months Ended July 31,		
	2006(1)	**2005(1)(2)**	**2004(2)**
Total sales (Mcf)	135,118	17,885	

(1) Total sales volumes omits (i) gas consumed in operations and (ii) gas sales equivalent to royalty interests held by our various lessors.

(2) No gas was produced until January 2005.

Average Sales Prices and Production Costs

The following table sets forth the average sales price and average production costs for all of our gas production for the periods indicated.

	Twelve Months Ended July 31,		
	2006	**2005**	**2004**
Average gas sales price (per Mcf)	$ 8.34	$ 6.59	$
Average production cost (per Mcf)(1)	7.18	17.18	

(1) Production costs include a significant amount of fixed expenses required to operate a minimum number of wells. As the number of wells and production increase, these costs are expected to decrease on a per unit basis as they are spread over a greater amount of production.

Reserves

Proved reserves are the estimated quantities that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements (of which none existed as of July 31, 2005 and 2006, the dates of our estimates of proved reserves prepared by our independent reservoir engineer consultant, Schlumberger

Data & Consulting Services), but not on escalations based on future conditions. The following table shows our estimated proved developed and proved undeveloped reserves. Reserve information is net of royalty interests owned by our lessors. Proved developed and proved undeveloped reserves are reserves that could be commercially recovered under current economic conditions, operating methods and government regulations. Proved developed and undeveloped reserves are defined by SEC Rule 4-10(a)(2) of Regulation S-X.

	Net Reserves (MMcf) As of July 31,		
	2006	**2005**	**2004**
Estimated proved developed reserves	8,983	2,971	
Estimated proved undeveloped reserves	5,735	7,321	
Total estimated proved developed and undeveloped reserves	14,718	10,292	

Discounted Future Cash Flows

The following table shows our standardized measure of discounted future net cash flows, based on our estimated proved developed and undeveloped reserves (discounted at a rate of 10%), net of taxes:

	As of July 31,		
	2006	**2005**	**2004**
	(In thousands)		
Total standardized measure of discounted future net cash flows	$ 32,734	$ 23,068	
Prices used in calculating reserves (per Mcf)	7.22	7.44	

Legal Proceedings

On June 23, 2006, our wholly owned subsidiary BPI Energy, Inc. entered into a Settlement and Mutual Release Agreement with Colt LLC (Colt), AFC Coal Properties, Inc. (AFC), American Premier Underwriters, Inc. (APU) and Central States Coal Reserves of Illinois, LLC (Central States). These parties were defendants in a lawsuit filed by BPI Energy, Inc. on March 15, 2006 relating to our Southern Illinois Basin Project.

The Settlement and Mutual Release Agreement provides that all parties to the lawsuit will release all of the other parties from any claims they may have had against each other. In addition, as conditions precedent to the settlement of claims, BPI Energy, Inc. (i) paid Colt $3,000,000; (ii) acknowledged that the Oil, Gas and Coalbed Methane Gas Lease dated April 3, 2001, as amended (the Lease), had lapsed and surrendered any interest it had in the Lease; and (iii) received a quitclaim deed from Colt with respect to the CBM estate covering a 10,000 acre portion of the 43,000 acres previously covered by the Lease.

Contemporaneously with the execution of the Settlement and Mutual Release Agreement, BPI Energy, Inc. entered into a Purchase and Sale Agreement with Colt pursuant to which it acquired ownership of the CBM estate covering approximately 10,000 of the 43,000 acres previously covered by the Lease. This acreage includes all of the currently producing CBM wells and proved reserves at our Southern Illinois Basin Project. The quitclaim deed executed by Colt provides that CBM operations take priority over coal mining operations for as long as CBM is being produced from the covered acreage. However, Colt has the right to acquire any CBM wells located in these 10,000 acres. If Colt exercises this option, it will be required to (i) to immediately plug any such well so acquired and (ii) pay the fair market value (as established by a mutually agreed upon expert) of such well.

As an additional condition precedent to the execution of the Settlement and Mutual Release Agreement, on June 23, 2006, the parties entered into a Termination Agreement with Colt, AFC, APU and Central States (collectively with BPI Energy, Inc., the Parties). This Termination Agreement acknowledged the termination and lapse of the Lease. All of the Parties agreed to discharge and release each of the other Parties from any and all obligations under the Lease.

Consolidated Financial Statements of BPI Energy Holdings, Inc.
as of July 31, 2006 and 2005 and for the Fiscal Years Ended July 31, 2006, 2005 and 2004

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders of
BPI Energy Holdings, Inc.
Solon, Ohio

We have audited the accompanying consolidated balance sheets of BPI Energy Holdings, Inc. and its subsidiary as of July 31, 2006 and 2005, and the related statements of operations, shareholders equity, and cash flows for the fiscal 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, 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 BPI Energy Holdings, Inc. and its subsidiary as of July 31, 2006 and 2005, and the results of its operations and its cash flows for the fiscal years then ended, in conformity with accounting principles generally accepted in the United States of America.

/s/ MEADEN & MOORE, LTD.
Certified Public Accountants

October 13, 2006
Cleveland, Ohio

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

DEVISSER GRAY
CHARTERED ACCOUNTANTS

401-905 West Pender Street
Vancouver, BC Canada
V6C 1L6

Tel: (604) 687-5447
Fax: (604) 687-6737

The Board of Directors and Shareholders of BPI Energy Holdings, Inc.,

We have audited the accompanying consolidated statement of operations, shareholders equity and cash flows of BPI Energy Holdings, Inc. and its subsidiary for the fiscal year ended July 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 audit.

We conducted our audit in accordance with standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an 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 audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the results of operations and cash flows of BPI Energy Holdings, Inc. and its subsidiary for the fiscal year ended July 31, 2004 in conformity with accounting principles generally accepted in the United States of America.

/s/ De Visser Gray

CHARTERED ACCOUNTANTS

Vancouver, British Columbia
October 12, 2004

BPI ENERGY HOLDINGS, INC.

Consolidated Balance Sheets

	July 31 2006	July 31 2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 19,279,015	$ 7,251,503
Accounts receivable	105,711	34,671
Other current assets	164,764	23,534
Total current assets	19,549,490	7,309,708
Property and equipment, at cost:		
Oil and gas properties, full cost method of accounting:		
Proved, net of accumulated depreciation, depletion and amortization of $331,150 and $58,523	20,766,898	10,190,929
Unproved, excluded from amortization	3,368,231	3,149,372
Net oil and gas properties	24,135,129	13,340,301
Other property and equipment, net of accumulated depreciation and amortization of $631,015 and $398,988	5,106,236	1,769,812
Net property and equipment	29,241,365	15,110,113
Investment in Hite Coalbed Methane, L.L.C.		846,766
Restricted cash	100,000	100,000
Other non-current assets	161,125	161,125
Total assets	$ 49,051,980	$ 23,527,712
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 1,492,239	$ 2,144,066
Current maturities of long-term notes payable	140,866	42,227
Accrued liabilities and other	649,237	31,405
Total current liabilities	2,282,342	2,217,698
Long-term notes payable, less current maturities	75,149	507,595
Asset retirement obligation	70,754	
Total liabilities	2,428,245	2,725,293
Shareholders Equity		
Common shares, no par value, authorized 200,000,000 shares, 70,812,540 and 43,912,961 issued and outstanding	67,946,143	34,666,022
Additional paid-in capital	5,871,120	4,493,680
Accumulated deficit	(27,193,528)	(18,357,283)

Total shareholders equity	46,623,735	20,802,419
Total liabilities and shareholders equity	$ 49,051,980	$ 23,527,712

See notes to consolidated financial statements

BPI ENERGY HOLDINGS, INC.

Consolidated Statements of Operations

	Years Ended July 31		
	2006	**2005**	**2004**
Revenue			
Gas sales	$ 1,126,477	$ 117,835	$
Operating expenses			
Lease operating expense	970,791	307,178	
General and administrative expenses	6,576,131	5,805,121	1,000,107
Depreciation, depletion and amortization	570,303	260,141	80,417
Total operating expenses	8,117,225	6,372,440	1,080,524
Operating loss	(6,990,748)	(6,254,605)	(1,080,524)
Other income (expense):			
Interest income	941,351	123,219	2,008
Interest expense	(22,405)	(24,820)	(15,165)
Other income (expense)	(2,764,443)	35,385	2,454
	(1,845,497)	133,784	(10,703)
Loss before income taxes	(8,836,245)	(6,120,821)	(1,091,227)
Deferred income tax benefit		724,470	298,111
Net loss	$ (8,836,245)	$ (5,396,351)	$ (793,116)
Basic and diluted net loss per share	$ (0.14)	$ (0.14)	$ (0.03)
Weighted average common shares outstanding	62,789,319	37,665,019	25,007,327

See notes to consolidated financial statements

BPI ENERGY HOLDINGS, INC.

Consolidated Statements of Shareholders Equity

	Common Shares		Additional Paid-in	Accumulated	Common Shares	Total Shareholders
	Shares	Amount	Capital	Deficit	Issuable	Equity
Balance, July 31, 2003	22,278,752	$ 15,953,188	$ 968,972	$ (12,167,816)	$ 30,579	$ 4,784,923
Proceeds from stock options exercised	69,444	43,036				43,036
Net proceeds from shares issued in Private placement September 18, 2003	725,000	339,787			(30,579)	309,208
Net proceeds from shares issued in Private placement December 22, 2003(1)	1,975,000	928,259				928,259
Net proceeds from shares issued in Private placement April 27, 2004	3,326,100	1,972,510				1,972,510
Proceeds from shares issuable for warrants exercised					271,440	271,440
Stock-based compensation			193,796			193,796
Net loss				(793,116)		(793,116)
Balance, July 31, 2004	28,374,296	19,236,780	1,162,768	(12,960,932)	271,440	7,710,056
Proceeds from stock options exercised	2,254,333	1,617,005				1,617,005
Proceeds from warrants exercised	2,861,342	1,714,882			(271,440)	1,443,442
Net proceeds from shares issued in Private placement December 29, 2004(2)	2,400,000	2,793,854				2,793,854
Net proceeds from shares issued in Private placement December 30, 2004(3)	4,032,000	4,693,675				4,693,675
Net proceeds from shares issued in Private placement January 6, 2005(4)	3,723,200	4,334,199				4,334,199
Net proceeds from shares issued in Private placement January 12,	216,800	252,378				252,378

2005(5)						
Bonus shares	50,990	23,249				23,249
Stock-based compensation			3,344,738			3,344,738
Other			(13,826)			(13,826)
Net loss				(5,396,351)		(5,396,351)
Balance, July 31, 2005	43,912,961	34,666,022	4,493,680	(18,357,283)		20,802,419
Proceeds from stock options exercised	396,667	382,239				382,239
Proceeds from warrants exercised	5,822,075	5,013,928				5,013,928
Net proceeds from shares issued in Private placement September 23, 2005(6)	18,000,000	27,883,954				27,883,954
Stock-based compensation stock options			527,327			527,327
Stock-based compensation common shares, including vested portion of restricted stock	758,514		850,113			850,113
Restricted stock, less vested portion	1,922,323					
Net loss				(8,836,245)		(8,836,245)
Balance, July 31, 2006	70,812,540	$ 67,946,143	$ 5,871,120	$ (27,193,528)	$	$ 46,623,735

(1) net of share issuance costs of $18,730

(2) net of share issuance costs of $206,146

(3) net of share issuance costs of $346,325

(4) net of share issuance costs of $319,801

(5) net of share issuance costs of $18,622

(6) net of share issuance costs of $2,619,953

See notes to consolidated financial statements

BPI ENERGY HOLDINGS, INC.

Consolidated Statements of Cash Flows

	Years Ended July 31		
	2006	**2005**	**2004**
Cash Provided by (Used in):			
Operating Activities			
Net loss	$ (8,836,245)	$ (5,396,351)	$ (793,116)
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation, depletion and amortization	570,303	260,141	80,417
Stock-based compensation expense	1,377,440	3,344,738	193,796
Gain on sale of investments and marketable securities	(127,416)	(42,276)	(2,454)
Loss on disposal of property and equipment		16,415	
Deferred income tax benefit		(724,470)	(298,111)
Other	11,024	20,339	(564)
Changes in assets and liabilities:			
Accounts receivable	(71,040)	(34,671)	
Other current assets	(141,230)	21,392	(26,909)
Accounts payable	8,116	80,913	7,699
Accrued liabilities and other	649,014	11,012	20,393
Other non-current assets		(31,625)	(88,000)
Net cash used in operating activities	(6,560,034)	(2,474,443)	(906,849)
Investing Activities			
Proceeds from sale of marketable securities and investments	551,000	113,557	5,407
Business acquisition, net of cash acquired		(857,638)	
Additions to oil and gas properties	(11,784,236)	(4,032,681)	(1,413,729)
Additions to other property and equipment	(3,284,057)	(1,383,208)	(191,794)
Acquisition of equity interest in joint venture		(78,112)	(100,500)
Investment in Hite Coalbed Methane, L.L.C.			(86,766)
Increase in restricted cash		(100,000)	
Net cash used in investing activities	(14,517,293)	(6,338,082)	(1,787,382)
Financing Activities:			
Payments on long-term notes payable	(175,282)	(41,320)	(26,014)
Net proceeds from issuance of common shares	33,280,121	15,134,553	3,524,453
Net cash provided by financing activities	33,104,839	15,093,233	3,498,439
Net increase in cash and cash equivalents	12,027,512	6,280,708	804,208
Cash and cash equivalents at the beginning of the year	7,251,503	970,795	166,587
Cash and cash equivalents at the end of the year	$ 19,279,015	$ 7,251,503	$ 970,795

Supplementary cash flow information:

Cash payments						
Interest paid	$	18,483	$	11,540	$	2,425
Non-cash investing and financing activities:						
Acquisition of equipment by issuance of notes payable		233,475		118,049		105,847
Cancellation of convertible note payable		392,000				
Cashless exercise of warrants		283,557				

See notes to consolidated financial statements

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements
July 31, 2006, 2005 and 2004

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Going Concern

These consolidated financial statements include the accounts of BPI Energy Holdings, Inc. and its wholly owned U.S. subsidiary, BPI Energy, Inc. (collectively, the Company). The Company has presented these financial statements in accordance with U.S. generally accepted accounting principles (GAAP). All inter-company transactions and balances have been eliminated upon consolidation.

BPI Energy Holdings, Inc. is incorporated in British Columbia, Canada and, through its wholly owned U.S. subsidiary, BPI Energy, Inc., is involved in the exploration, production and commercial sale of coalbed methane (CBM) located in the Illinois Basin. The Company conducts its operations in one reportable segment, which is oil and gas exploration and production. On December 13, 2005, the Company s common shares began trading on the American Stock Exchange (AMEX) under the symbol BPG. As a result of the shares being listed on the AMEX, the Company voluntarily de-listed from trading its shares on the TSX Venture Exchange. Amounts shown are in U.S. Dollars unless otherwise indicated.

These consolidated financial statements have been prepared on the basis of accounting principles applicable to a going concern, which contemplates the Company s ability to realize its assets and discharge its liabilities in the normal course of business; however, the occurrence of significant losses to date raises doubt upon the validity of this assumption. The ability of the Company to realize the costs it has incurred to date on these properties is dependent upon the Company being able to sell the properties or to develop profitable operations, to finance their exploration and development costs and to resolve any environmental, regulatory or other constraints, which may hinder the successful development of the properties.

The Company has experienced significant losses over the past five years, including $8,836,245 in the current year, and has an accumulated deficit of $27,193,528 at July 31, 2006. The Company s continued existence as a going concern is dependent upon its ability to continue to obtain adequate financing arrangements and to achieve and maintain profitable operations.

The Company has financed its activities primarily from the proceeds of various share issuances. As a result of the Company being in the early stages of operations, the recoverability of assets on the balance sheet will be dependent on the Company s ability to obtain additional financing and to attain a level of profitable operations.

Use of Estimates

The preparation of these consolidated financial statements requires the use of certain estimates by management in determining the Company s assets, liabilities, revenues and expenses. Actual results could differ from such estimates. Depreciation, depletion and amortization of oil and gas properties and the impairment of oil and gas properties are determined using estimates of oil and gas reserves. There are numerous uncertainties in estimating the quantity of reserves and in projecting the future rates of production and timing of development expenditures, including the timing and costs associated with the Company s asset retirement obligations. Oil and gas reserve engineering must be recognized as a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way. Proved reserves of oil and natural gas are estimated quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under existing conditions.

Revenue Recognition and Customer Concentration

All revenue from gas sales is recognized after the gas is produced and delivery takes place. The Company currently sells all of its gas to one gas marketing company, Atmos Energy Marketing, LLC. Although the Company sells all of its production to a single purchaser, there are numerous other purchasers in the Illinois Basin to whom the

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

Company believes it could sell its production; therefore, the loss of its single purchaser would not adversely affect the Company s operations.

Investments in Unconsolidated Entities

The equity method of accounting is used to account for investments in and earnings or losses of affiliates that the Company does not control, but over which it does exert significant influence. The cost method of accounting is used for all other non-controlled investments. The Company used the cost method to account for its indirect interest in the Jericho Project through its 49% interest in Hite Coalbed Methane, L.L.C. (HCM), as the Company did not exert significant influence over HCM. As described in note 4 below, the Company sold its investment in HCM during the fiscal year ended July 31, 2006 and recognized a gain on the sale in the amount of $127,416. The Company considers whether the fair values of any of its investments have declined below their carrying value whenever adverse events or changes in circumstances indicate that recorded values may not be recoverable. If the Company considered any such decline to be other than temporary, a write-down would be recorded to estimated fair value.

Cash and Cash Equivalents

Cash and cash equivalents consist of highly liquid investments with a maturity date of three months or less when purchased and are carried at cost, which approximates fair value.

Accounts Receivable

Accounts receivable represents amounts due from Atmos Energy Marketing, LLC for gas sales. Management regularly reviews accounts receivable to determine whether amounts are collectible and records a valuation allowance to reflect management s best estimate of any amount that may not be collectible. At July 31, 2006 and 2005, the Company has determined that no allowance for uncollectible receivables was necessary.

Fair Value of Financial Instruments

The carrying amount reported in the balance sheet for cash, accounts receivable, accounts payable and accrued liabilities approximates fair value because of the immediate or short-term maturity of these financial instruments.

The carrying amount of long-term notes payable approximates fair value based on current rates available to the Company for instruments of the same remaining terms and maturities.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas properties. Under this method, all costs associated with the acquisition of, exploration for and development of oil and gas reserves are capitalized in cost centers on a country-by-country basis (currently the Company has one cost center, the United States). Such costs include lease acquisition costs, geological and geophysical studies, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells, and overhead expenses directly related to these activities. Internal costs associated with oil and gas activities that are not directly attributable to acquisition, exploration or development activities are expensed as incurred.

Unproved oil and gas properties and major development projects are excluded from amortization until a determination of whether proved reserves can be assigned to the properties or impairment occurs. Unproved properties are assessed at least annually to ascertain whether an impairment has occurred. Sales or dispositions of properties are credited to their respective cost centers and a gain or loss is recognized when all the properties in a cost center have been disposed of, unless such sale or disposition significantly alters the relationship between capitalized costs and proved reserves attributable to the cost center.

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

Capitalized costs of proved oil and gas properties, including estimated future costs to develop the reserves and estimated abandonment cost, net of salvage, are amortized on the units-of-production method using estimates of proved reserves.

A ceiling test is applied to each cost center by comparing the net capitalized costs, less related deferred income taxes, to the estimated future net revenues from production of proved reserves, discounted at 10%, plus the costs of unproved properties net of impairment. Any excess capitalized costs are written-off in the current year. The calculation of future net revenues is based upon prices, costs and regulations in effect at each year end.

In general, the Company determines if an unproved property is impaired if one or more of the following conditions exist:

i) there are no firm plans for further drilling on the unproved property;

ii) negative results were obtained from studies of the unproved property;

iii) negative results were obtained from studies conducted in the vicinity of the unproved property;

iv) the remaining term of the unproved property does not allow sufficient time for further studies or drilling.

No impairment existed as of July 31, 2006 and 2005.

Other Property and Equipment

Other property and equipment are stated at cost. Gas collection equipment primarily represents flowlines purchased and installed to transport the CBM from the wells to the compressor station. Support equipment includes vehicles, machinery and other equipment used in oil and gas activities. Other equipment primarily includes office furniture and fixtures and computer equipment. Gas collection equipment is depreciated on the units-of-production method using estimates of proved reserves. Support equipment and other property and equipment are depreciated using the straight-line method over the estimated useful lives of the assets, ranging from three to ten years. Major classes of other property and equipment consisted of the following:

	July 31	
	2006	**2005**
Other Property and Equipment:		
Gas collection equipment	$ 4,342,400	$ 1,332,012
Support equipment	1,046,989	760,467
Other	347,862	76,321
Less: Accumulated depreciation and amortization	(631,015)	(398,988)
	$ 5,106,236	$ 1,769,812

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BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

Accrued Liabilities

Accrued liabilities consist of the following:

	At July 31 2006	2005
Employee compensation	$ 467,869	$
Professional fees	111,805	
Directors fees	31,000	
Other	34,428	31,405
	$ 645,102	$ 31,405

Asset Retirement Obligations

The Company follows Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations. SFAS No. 143 requires the Company to record the fair value of an asset retirement obligation as a liability in the period in which it is incurred, if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement costs is capitalized as part of the carrying amount of the associated long-lived asset. Amortization of the capitalized asset retirement cost is computed on a units-of-production method. Accretion of the asset retirement obligation is recognized over time until the obligation is settled. The future cash outflows associated with settling the asset retirement obligations accrued on the accompanying consolidated balance sheets are excluded from the ceiling test calculation. The Company s asset retirement obligations relate to the plugging of wells upon exhaustion of gas reserves. The Company assessed its asset retirement obligation in prior periods and deemed it to be immaterial. The initial liability for our asset retirement obligations was recorded as of August 1, 2005 in the amount of $34,708.

The following table summarizes the activity for the Company s asset retirement obligations for the fiscal year ended July 31, 2006:

Asset retirement obligation at beginning of period	$ 34,708
Accretion expense	3,072
Change in estimates	7,952
Liabilities incurred	25,022
Asset retirement obligation at end of period	$ 70,754

Accounting for Long-Lived Assets

The Company follows Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets (SFAS No. 144). Under SFAS No. 144, all long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying value may not be recoverable. The carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. An impairment loss is recognized when the carrying value of a long-lived asset is not recoverable and exceeds its fair value.

Income Taxes

Income taxes are accounted for under the asset and liability method that requires deferred income taxes to reflect the future tax consequences attributable to differences between the tax and financial reporting bases of assets and liabilities. Deferred tax assets and liabilities recognized are based on the tax rates in effect in the year in which differences are expected to reverse. Deferred tax assets are reduced by a valuation allowance when, in the opinion of

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

management based on available evidence, it is more likely than not that some or all of any net deferred tax assets will not be realized.

Share-Based Payment

Prior to December 13, 2005, the Company administered a stock-based compensation plan (the Incentive Stock Option Plan) under which stock options were issued to directors, officers, employees and consultants as determined by the Board of Directors and subject to the provisions of the Incentive Stock Option Plan. The Incentive Stock Option Plan permitted options to be issued with exercise prices at a discount to the market price of the Company s common shares on the day prior to the date of grant. However, the majority of all stock options issued under the Incentive Stock Option Plan were issued with exercise prices equal to the quoted market price of the stock on the date of grant. Options granted under the Incentive Stock Option Plan vested immediately and were exercisable over a period not exceeding five years. The Company had 1,823,265 options outstanding under the Incentive Stock Option Plan at July 31, 2006.

On December 13, 2005, the shareholders of the Company approved the 2005 Omnibus Stock Plan (the Omnibus Stock Plan) and it became effective on that date. The Omnibus Stock Plan replaces the Incentive Stock Option Plan under which stock options were previously granted. The Omnibus Stock Plan is administered by the Compensation Committee of the Board of Directors (the Committee) and will remain in effect for five years. All employees and directors of the Company and its subsidiaries, and all consultants or agents of the Company designated by the Committee, are eligible to participate in the Omnibus Stock Plan. The Committee has authority to: grant awards; select the participants who will receive awards; determine the terms, conditions, vesting periods and restrictions applicable to the awards; determine how the exercise price is to be paid; modify or replace outstanding awards within the limits of the Omnibus Stock Plan; accelerate the date on which awards become exercisable; waive the restrictions and conditions applicable to awards; and establish rules governing the Omnibus Stock Plan. No options have been issued under the Omnibus Stock Plan. During the current fiscal year, the Committee granted stock awards under the Omnibus Stock Plan in the form of restricted and unrestricted stock to employees and directors of the Company. The transactions involving the granting of these stock awards are described more fully in Note 11.

In December 2004, the FASB issued SFAS No. 123(R), Share-Based Payment. This Statement revises SFAS No. 123, Accounting for Stock-Based Compensation and supersedes APB Opinion No. 25, Accounting for Stock Issued to Employees. SFAS No. 123(R) focuses primarily on the accounting for transactions in which an entity obtains employee services in share-based payment transactions. The key provision of SFAS No. 123(R) requires companies to record share-based payment transactions as compensation expense at fair market value based on the grant-date fair value of those awards. Previously under SFAS 123, companies had the option of either recording expense based on the fair value of stock options granted or continuing to account for stock-based compensation using the intrinsic value method prescribed by APB No. 25.

The Company adopted SFAS No. 123(R), using the modified-prospective method, effective August 1, 2005. Since August 1, 2001, the Company followed the fair value provisions of SFAS 123 and recorded all share-based payment transactions as compensation expense at fair market value based on the grant-date fair value of those awards. In addition, all stock options previously granted by the Company vested immediately on the date of grant and, thus, there was no unvested portion of previous stock option grants that vested during the fiscal year ended July 31, 2006. Therefore, SFAS 123(R) had no impact on the Company s consolidated financial position or results of operations for the fiscal year ended July 31, 2006. The Company uses the Black-Scholes formula to estimate the fair value of stock options granted.

Loss Per Share

Basic loss per share is calculated using the weighted average number of common shares outstanding during the year. Diluted loss per share reflects the potential dilution that could occur if securities or other contracts to issue

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

common shares were exercised or converted into common shares. Restricted common shares granted are included in the computation only after the shares become fully vested. Diluted loss per share is not disclosed as it is anti-dilutive. Outstanding options, warrants and unvested shares of restricted stock that were excluded from the computation of diluted loss per share, as the effect of their assumed exercises/vesting would be anti-dilutive, totaled 9,057,188, 15,786,491 and 10,427,910 at July 31, 2006, 2005 and 2004, respectively.

Reclassifications

Certain items included in prior years consolidated financial statements have been reclassified to conform to current year presentation.

Impact of Recently Issued Accounting Standards Not Yet Adopted

In June 2006, the FASB issued FASB Interpretation Number 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109. This Interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, Accounting for Income Taxes. This Interpretation is effective for fiscal years beginning after December 15, 2006. The Company is currently assessing the effect of this Interpretation, if any, on its consolidated financial statements.

2. MARKETABLE SECURITIES

The Company sold its remaining 432,000 shares of Pyng Technologies Corp. (Pyng), a TSX Venture listed public company, during the fiscal year ended July 31, 2005 and recognized a gain on the sale in the amount of $42,276. The gain is included within other income in the statement of operations. The Company considered these shares of Pyng to be trading securities and recorded unrealized holding gains and losses directly to earnings.

3. PURCHASE OF ILLINOIS MINE GAS, L.L.C.

On March 3, 2005, the Company purchased the remaining interest in Illinois Mine Gas, L.L.C. (IMG), a 50% joint venture with Vessels Coal Gas, Inc. IMG was created to explore and develop abandoned mine works in the Illinois Basin for the extraction and sale of methane gas. The Company previously accounted for its 50% investment in IMG under the equity method of accounting. The aggregate purchase price of $899,681 in cash, less cash received in the amount of $42,043, was assigned entirely to IMG s coal mine methane properties.

4. SALE OF INVESTMENT IN HITE COALBED METHANE, L.L.C.

On January 4, 2006, the Company sold its 49% interest in Hite Coalbed Methane, L.L.C. (HCM) for $551,000 in cash and cancellation of the Company s convertible note payable in the amount of $392,000, plus accrued interest of $31,182. The note was convertible into 390,537 of the Company s common shares. The Company accounted for its investment in HCM under the cost method of accounting. The total consideration received of $974,182 resulted in a gain on the sale of the investment of $127,416, which is included in other income in the Company s statement of operations for the fiscal year ended July 31, 2006. The Company also received its final distribution of net income from HCM during the fiscal year ended July 31, 2006 in the amount of $51,452, which is included as part of other income (expense), net in the statement of operations for the fiscal year ended July 31, 2006.

5. RESTRICTED CASH

The Company negotiated an agreement (Agreement) with one of its surface rights owners to ensure the Company s access to its wells and gas gathering systems. As part of the Agreement, the Company deposited $100,000 in a trust account to serve as a performance bond to ensure the Company performs its obligations under the terms of the Agreement. The Company has recorded this amount as a non-current asset at July 31, 2006 and 2005.

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Notes to Consolidated Financial Statements (Continued)

6. LONG-TERM NOTES PAYABLE

The Company has outstanding notes payable as follows:

	July 31 2006	July 31 2005
Case Credit term note due in fiscal year 2007, 6.50%	$ 15,410	$ 32,833
GMAC term note due in fiscal year 2009, 6.50%	20,608	26,633
GMAC term notes due in fiscal year 2010, 6.1% to 6.50%	80,849	98,356
Convertible note due in fiscal year 2008, 3.25%		392,000
Caterpillar Financial Services term note due in fiscal year 2007, 7.0%	99,148	
	216,015	549,822
Less current maturities	(140,866)	(42,227)
Long-term notes payable	$ 75,149	$ 507,595

The notes are collateralized by the related vehicles and equipment. The convertible note payable outstanding at July 31, 2005 was issued in June 2003 with a face value of $392,000 and maturing on June 10, 2008, bearing interest at 3.25%, convertible at the option of the holder, prior to June 10, 2008, into 390,537 common shares of the Company. The convertible note payable was cancelled on January 4, 2005 pursuant to the sale of the Company s interest in Hite Coalbed Methane, L.L.C. see Note 4.

The annual maturities of all notes for the five fiscal years subsequent to July 31, 2006 are as follows:

	Principal	Interest	Total
2007	$ 140,866	$ 7,735	$ 148,601
2008	27,982	3,855	31,837
2009	29,767	2,070	31,837
2010	17,400	440	17,840
2011			
	$ 216,015	$ 14,100	$ 230,115

7. INCOME TAXES

The income tax benefit consists of the following:

	Year Ended July 31 2006	2005	2004
Current	$	$	$
Deferred:			
Canadian			
United States		(581,582)	(239,314)
U.S. state taxes		(142,888)	(58,797)
Total deferred income taxes		(724,470)	(298,111)
Total income tax benefit	$	$ (724,470)	$ (298,111)

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Notes to Consolidated Financial Statements (Continued)

A reconciliation of income tax computed at the statutory Canadian tax rate and the Company s effective rate is as follows:

	Year Ended July 31		
	2006	**2005**	**2004**
Statutory Canadian income tax rate	(36.00)%	(36.00)%	(36.00)%
Stock-based compensation	(4.71)%	19.66%	6.39%
Non-deductible stock issuance costs	2.10%	1.43%	%
Current year Canadian loss with no tax benefit	4.61%	2.32%	6.14%
Net change in deductible temporary differences due to foreign currency conversion and expired losses	3.16%	(5.38)%	(4.47)%
Increase in valuation allowance	43.44%	7.32%	2.57%
Other	(3.38)%	(1.19)%	(1.95)%
Effective income tax rate	%	(11.84)%	(27.32)%

The components of the net deferred tax liability at July 31, 2006 and 2005 are shown below:

	July 31, 2006		
	United States	**Canada**	**Total**
Deferred tax assets:			
Net operating loss carryforwards	$ 11,363,979	$ 513,104	$ 11,877,083
Stock-based compensation	769,416		769,416
Resource related allowances		1,762,037	1,762,037
Total non-current deferred tax asset	12,133,395	2,275,141	14,408,536
Valuation allowance	(4,465,611)	(2,275,141)	(6,740,752)
Net deferred tax assets	7,667,784		7,667,784
Deferred tax liabilities:			
Net property plant and equipment	(7,667,784)		(7,667,784)
Total non-current deferred tax liability	(7,667,784)		(7,667,784)
Net deferred tax liability	$	$	$

	July 31, 2005		
	United States	Canada	Total
Deferred tax assets:			
Net operating loss carryforwards	$ 4,130,549	$ 643,332	$ 4,773,881
Resource related allowances		1,705,249	1,705,249
Investments and advances to subsidiaries		375,215	375,215
Total non-current deferred tax asset	4,130,549	2,723,796	6,854,345
Valuation allowance	(261,405)	(2,640,396)	(2,901,801)
Net deferred tax assets	3,869,144	83,400	3,952,544
Deferred tax liabilities:			
Net property plant and equipment	(3,869,144)	(83,400)	(3,952,544)
Total non-current deferred tax liability	(3,869,144)	(83,400)	(3,952,544)
Net deferred tax liability	$	$	$

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Notes to Consolidated Financial Statements (Continued)

The Company considers the need to record a valuation allowance against deferred tax assets on a country-by-country basis, taking into account the effects of local tax law. A valuation allowance is not recorded when it is determined that sufficient positive evidence exists to demonstrate that it is more likely than not that a deferred tax asset will be realized. The main factors considered are: (1) the nature, amount and expected timing of reversal of taxable temporary differences, and (2) opportunities to implement tax plans that affect whether tax assets can be realized. A valuation allowance has been recorded against the net deferred tax assets as of July 31, 2006 and 2005 because the Company believes it is more likely than not it will be unable to realize the benefit of these assets.

An increase in the U.S. valuation allowance of $4,204,206 has been recorded during the current fiscal year to reduce the amount of the U.S. deferred tax assets to an amount equal to the recorded U.S. deferred tax liabilities. A decrease in the Canadian valuation allowance of $365,255 has been recorded during the current fiscal year to reflect miscellaneous income and the expiration of net operating losses in Canada. Historically, the Company has had no income generating operations in Canada and any future income is too uncertain to justify not recording a valuation allowance.

The Company s net operating loss carryforwards at July 31, 2006 expire as follows:

	Year Ended July 31			
	2009	2010	2011 and Later	Total
Canadian	$ 234,848	$ 296,493	$ 893,949	$ 1,425,290
United States			29,138,408	29,138,408
	$ 234,848	$ 296,493	$ 30,032,357	$ 30,563,698

At July 31, 2006 the Company also has $4,894,546 of Canadian resource related deductions that have no expiration date.

8. SHAREHOLDERS EQUITY

Common shares The Company has authorized 200,000,000 shares without par value, of which 70,812,540 and 43,912,961 were issued and outstanding as of July 31, 2006 and 2005, respectively. Shares issued and outstanding at July 31, 2006 include 2,325,000 of restricted shares, of which 402,677 have vested as of July 31, 2006.

Additional paid-in capital Amounts recorded of $5,871,120 and $4,493,680 at July 31, 2006 and 2005, respectively, represent the cumulative amounts charged to stock-based compensation expense as of each fiscal year-end.

Common shares issuable Amount recorded of $271,440 at July 31, 2004 represents proceeds received in advance of the exercise of warrants to purchase common shares.

In September 2005, the Company sold 18,000,000 common shares in a private placement. The proceeds from this private placement of $27,883,954, net of $2,619,953 of share issuance costs, are being used to fund the Company s plan of operations and for working capital and general corporate purposes.

During fiscal year 2005, the Company issued 10,372,000 shares at $1.25 per share with 5,186,000 share purchase warrants exercisable at $1.50 for a period of two years (Investor Warrants). The Company s agent received a commission of 5% and 1,037,200 broker warrants exercisable at $1.25 for a period of two years (Agent Warrants). The shares and warrants, when issued, were restricted under the U.S. Securities Act, and the Company was required to register the resale of the shares and the shares underlying the warrants with the Securities and Exchange Commission. Upon registration of the shares underlying the warrants and the delisting of such shares from the TSX Venture Exchange, the Investor Warrants were extended to be exercisable for two years after such listing and the Agent warrants were extended to be exercisable for five years after the closing of the share placement.

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Notes to Consolidated Financial Statements (Continued)

Share purchase warrants outstanding at July 31, 2006 are as follows:

Number Outstanding	Exercise Price	Expiry Date
4,274,400	$ 1.50	December 13, 2007
643,200	$ 1.25	December 31, 2009
394,000	$ 1.25	January 12, 2010
5,311,600		

9. COMMITMENTS AND CONTINGENCIES

The Company has operating lease commitments expiring at various dates. Such leases generally contain renewal options. At July 31, 2006, future minimum lease payments under non-cancellable operating leases are as follows:

2007	$ 219,141
2008	123,714
2009	87,371
2010	14,600
2011	15,184
Thereafter	262,557
	$ 722,567

The leases are principally for office space and gas collection equipment. Rental payments for all operating leases amounted to approximately $143,000 during the fiscal year ended July 31, 2006.

Certain of the Company s mineral leases and farm-out agreements are subject to annual minimum royalty payments required to hold the mineral leases and farm-out agreements. Although the Company is not obligated to make these payments under existing mineral leases and farm-out agreements, these payments are required to maintain individual leases/farm-out agreements after the expiration of the initial terms of the lease/farm-out agreements. The mineral leases/farm-out agreements in existence as of July 31, 2006 expire at various dates beginning in November 2007. If the Company were to pay the total minimum royalty payments due under all mineral leases/farm-out agreements in existence as of July 31, 2006, the amount would initially total approximately $100,000 annually and could increase to as much as $220,000 annually.

10. CONCENTRATIONS

Financial instruments that potentially subject the Company to concentrations of credit risk consist of cash and cash equivalents, which are held at one large high quality financial institution. The Company periodically evaluates the credit worthiness of the financial institution. The Company has not incurred any credit risk losses related to its cash and cash equivalents.

The Company utilizes a limited number of drilling contractors to perform all of the drilling on its projects. The Company maintains a limited number of supervisory and field personnel to oversee drilling and production operations. The Company s plans to drill additional wells are determined in large part by the anticipated availability of acceptable drilling equipment and crews. The Company does not currently have any contractual commitments that ensure it will have adequate drilling equipment or crews to achieve its drilling plans. The Company believes that it can secure the necessary commitments from drilling companies as required. However, it can provide no assurance that its expectations regarding the availability of drilling equipment and crews from these companies will be met. A

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Notes to Consolidated Financial Statements (Continued)

significant delay in securing the necessary drilling equipment and crews could cause a delay in production and sales, which would affect operating results adversely.

11. STOCK-BASED COMPENSATION

Stock Options

The table below summarizes stock options activity for the three years ended July 31, 2006. All stock options were granted under the Incentive Stock Option Plan with exercise prices denominated in Canadian Dollars. U.S. Dollar amounts shown in the table below were derived using published exchange rates on the date of the transaction for grants, expirations, exercises and surrenders and at year-end exchange rates for options outstanding as of July 31.

		Weighted-Average Exercise Price	
	Number of Options	**CAD$**	**USD$**
Outstanding at July 31, 2003	1,825,000	$ 0.81	$ 0.58
Granted exercise price less than market price of stock on date of grant	475,000	0.65	0.49
Exercised	(69,444)	0.82	0.62
Outstanding at July 31, 2004	2,230,556	0.78	0.59
Granted exercise price equals market price of stock on date of grant	3,423,278	2.04	1.64
Granted exercise price less than market price of stock on date of grant	852,778	1.19	0.96
Expired	(25,000)	1.20	0.98
Exercised	(2,254,333)	0.87	0.72
Outstanding at July 31, 2005	4,227,279	1.82	1.49
Granted exercise price equals market price of stock on date of grant	495,000	2.05	1.79
Expired	(320,000)	2.29	1.79
Exercised	(554,014)	1.55	1.24
Exchanged for restricted stock	(2,025,000)	2.23	1.82
Outstanding at July 31, 2006	1,823,265	$ 1.46	$ 1.17

Included in stock options exercised during fiscal year 2006 are 107,800 stock options surrendered by an officer/director of the Company in order to exercise 173,250 warrants for the Company s common stock in lieu of transferring cash. The transaction occurred on April 28, 2006. The fair value of the stock options surrendered in this transaction equaled the total exercise price of the warrants using the Black-Scholes options pricing model to value the stock options on the date of the transaction. The assumptions used in the Black-Scholes option pricing model were as follows:

Risk-free interest rate	4.75%
Expected dividend yield	Nil
Expected stock price volatility	95%
Expected option life	3.6 years

The risk-free interest rate used was based on the U.S. Treasury yield curve at the time of the transaction. The expected stock price volatility was based solely on the historical volatility of the Company s common stock during

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Notes to Consolidated Financial Statements (Continued)

the historical period equivalent to the expected option life. In estimating expected volatility, the Company used a combination of the historical volatility of its stock for the period that it began trading on the American Stock Exchange and the historical volatility of its stock on the TSX Venture Exchange for the necessary period in order to reflect the expected remaining life of the stock options. The expected option life represents the remaining contractual life of the stock options surrendered.

The Company recorded stock-based compensation expense for stock options granted to employees and directors in the amount of $527,327, $3,344,738 and $193,796 in fiscal years ended July 31, 2006, 2005 and 2004, respectively. The fair value of stock options granted was estimated using the Black-Scholes option pricing model with the following assumptions:

	Year Ended July 31,		
	2006	**2005**	**2004**
Risk-free interest rate	3.3%	3.0 - 3.7%	4.1%
Expected dividend yield	Nil	Nil	Nil
Expected stock price volatility	95%	69-81%	105%
Expected option life	3 years	3 years	5 years

The risk-free interest rate for periods within the contractual life of the options was based on the U.S. Treasury yield curve in effect at the time of grant for options granted during fiscal year 2006 and based on the equivalent Canadian rate in prior fiscal years. The expected stock price volatility is based solely on the historical volatility of the Company s common stock during the historical period equivalent to the expected option life. In estimating expected volatility, the Company used the historical volatility of its stock on the TSX Venture Exchange as the Company had not yet began trading on the AMEX at the time the options were granted. The expected option life represents the Company s best estimate of the time that options granted are expected to be outstanding based on prior experience.

The weighted average fair value per option at the date of the grant for options granted in fiscal years ended July 31, 2006, 2005 and 2004 was as follows:

	2006	**2005**	**2004**
Exercise price equals market price of stock on date of grant	$ 1.07	$ 0.81	$
Exercise price is less than market price of stock on date of grant		0.66	0.55
Total grants	$ 1.07	$ 0.78	$ 0.55

Option pricing models require the input of highly subjective assumptions, particularly as to the expected price volatility of the stock. Changes in these assumptions can materially affect the fair value estimate, and therefore it is management s view that the existing models do not necessarily provide a single reliable measure of the fair value of the Company s stock option grants.

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Notes to Consolidated Financial Statements (Continued)

The following table summarizes information about options outstanding as of July 31, 2006:

Exercise Price CAD$	Number Outstanding	Remaining Life (Years)	Expiry Date
$ 0.65	345,000	2.3	November 3, 2008
0.90	243,334	0.4	January 10, 2007
0.90	10,000	3.1	September 22, 2009
1.20	50,000	0.4	January 10, 2007
1.49	695,666	3.3	November 29, 2009
2.05	10,000	4.1	September 23, 2010
2.19	136,000	3.7	March 27, 2010
2.40	333,265	3.5	January 20, 2010
$ 1.46	1,823,265	2.7	

Restricted Stock Awards and Grants of Common Shares

On April 12, 2006, the Compensation Committee approved an exchange of common shares for outstanding stock options held by various key employees and directors of the Company (Option Exchange). The Option Exchange effectively cancelled stock option awards for 2,025,000 of the Company s common shares previously granted during fiscal years ended 2005 and 2006. The Option Exchange replaced the cancelled options with restricted stock awards of 2,025,000 of the Company s common shares. The restrictions on the shares of restricted stock are scheduled to lapse on three separate dates as follows:

January 1, 2007	680,000 shares
January 1, 2008	680,000 shares
January 1, 2009	665,000 shares

The Company accounted for the Option Exchange as a modification of the original shared-based payment awards (stock options) in accordance with SFAS No. 123(R). Accordingly, the Company recorded compensation expense based on the excess of the fair value of the restricted stock award grants over the fair value of the original award (stock options) measured immediately before the transaction based on current circumstances. The fair value of the restricted stock awards was determined based on the number of shares granted and the quoted price of the Company s common shares on the date of the grant of $1.42 per share. The value of the stock options surrendered was computed immediately before the modification using the Black-Scholes valuation model with the following assumptions:

Risk-free interest rate	4.75%
Expected dividend yield	Nil
Expected stock price volatility	94% - 98%

Expected option remaining life	3.8 - 4.5 years

The risk-free interest rate used was based on the U.S. Treasury yield curve at the time of the transaction. The expected stock price volatility was based solely on the historical volatility of the Company s common stock during the historical period equivalent to the expected option life. In estimating expected volatility, the Company used a combination of the historical volatility of its stock for the period that it began trading on the American Stock Exchange and the historical volatility of its stock on the TSX Venture Exchange for the necessary period in order to reflect the expected remaining life of the stock options. The expected option life represents the remaining contractual life of the stock options surrendered.

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Notes to Consolidated Financial Statements (Continued)

The Option Exchange resulted in incremental compensation expense of $989,650, which will be recognized over the requisite service period. The Company recorded $139,728 of compensation expense related to the Option Exchange in the fiscal year ended July 31, 2006. Future amortization of the unearned incremental compensation expense will result in additional compensation expense of $385,621, $303,216 and $118,294 in fiscal years ended July 31, 2007, 2008 and 2009, respectively.

On April 28, 2006, the vesting of 84,163 shares of restricted stock issued to an officer/director of the Company in the Option Exchange described above was accelerated and the shares were surrendered by the officer/director in order to exercise 165,000 warrants for the Company s common stock in lieu of transferring cash. The accelerated vesting of the restricted stock resulted in $42,790 of compensation expense which was recorded in fiscal year 2006. The fair value of the stock surrendered in this transaction equalled the total exercise price of the warrants using the quoted market price of the Company s stock on the AMEX from the previous day to value the stock surrendered.

On April 12, 2006, the Company granted 300,000 shares of restricted stock and 300,000 unrestricted common shares to its newly hired Senior Vice President of Operations. The grant was made outside the Omnibus Stock Plan in accordance with AMEX Company Guide Rule 711. The fair value of the restricted stock was determined based on the number of shares granted and the quoted price of the Company s common shares on the date of the grant of $1.42 per share. The restrictions on the shares of restricted stock are scheduled to lapse on three separate dates in the amount of 100,000 shares each on April 12, 2007, 2008 and 2009. The grant of restricted stock resulted in compensation expense of $426,000, which will be recognized over the requisite service period. The Company recorded $42,795 of compensation expense related to this grant of restricted stock in the fiscal year ended July 31, 2006. Future amortization of the unearned compensation expense will result in additional compensation expense of $142,000, $142,000 and $99,205 in fiscal years ended July 31, 2007, 2008 and 2009, respectively. The Company recorded the fair value of the award of unrestricted common shares of $426,000 as compensation expense in the fiscal year ended July 31, 2006.

On April 12, 2006, the Company granted 140,000 unrestricted common shares to a newly appointed director. The Company recorded the fair value of the award of unrestricted common shares of $198,800 as compensation expense in the quarter ended April 30, 2006.

All restricted stock awards are subject to continuous employment. However, in the event employment is terminated before the restrictions lapse by reason of death, total disability or retirement, the restrictions will lapse on the date of termination as to a pro-rata portion of the number of shares of restricted stock scheduled to lapse on the next lapse date, based on the number of days continuously employed during the applicable vesting period. The Company includes all shares of restricted stock in common shares outstanding when issued, but only includes the vested portion of such shares in the computation of basic earnings per share.

The Company s policy is to issue new shares to satisfy stock option exercises and restricted stock grants upon receiving approval from the AMEX for the issuance of such shares.

12. LEGAL SETTLEMENT

On March 15, 2006, the Company filed a complaint against Colt LLC and other defendants alleging tortious interference with business relations and breach of contract relating to the interruptions of its development plans at the

Company s Southern Illinois Basin Project. The Company sought a preliminary injunction (which was denied by the court) against Colt LLC and related parties from terminating the lease agreement covering its CBM rights in 43,000 acres at the Southern Illinois Basin Project or taking any other action that interferes with the Company s right to produce CBM under the lease agreement, pending a final judgment on the merits of the complaint.

On April 5, 2006, Colt filed an answer and counterclaim in response to the Company s complaint. In its counterclaim, Colt sought a declaratory judgment asking the court to declare, among other things, that: (a) the Company committed multiple breaches of the lease agreement; (b) the lease agreement automatically terminated due to the Company s failure to cure its alleged breaches; (c) the lease agreement automatically terminated by its

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Notes to Consolidated Financial Statements (Continued)

own terms on April 3, 2006; and (d) to the extent the lease agreement already terminated, the Company is wrongfully holding over and/or trespassing and Colt is entitled to an award of damages as a result.

In June 2006, the Company reached a settlement with the defendants in this lawsuit. The following list summarizes the key terms of the settlement:

1. All parties released all the other parties from any claims they may have had against each other;

2. The Company paid Colt $3,000,000;

3. The Company surrendered any interest it had in the lease;

4. The Company acquired ownership of the CBM estate covering approximately 10,000 of the 43,000 acres previously covered by the lease (which acreage includes all of our producing CBM wells and proved reserves at our Southern Illinois Basin Project);

5. The Company was relieved of any future obligation to make royalty payments as was previously required under the terms of the lease (under the terms of the lease the Company was obligated to make royalty payments of 15% of gross sales and minimum royalties totaling at least $42,000 per month); and

6. The deed made clear that CBM operations take priority over coal mining operations for as long as CBM is being produced from the covered acreage; however, Colt has the right to acquire any CBM wells located in these 10,000 acres. If Colt exercises this option, it will be required to pay the fair market value (as established by a mutually agreed upon expert) of such well (which fair market value will include the value of any reserves that can be produced by such well).

In conjunction with this proposed settlement, during the fiscal year ended July 31, 2006 the Company recorded $2,951,608 as other expense and reclassified $2,225,816 from the cost of Unevaluated Properties to the cost of Proved Properties to recognize the impairment resulting from the loss of approximately 33,000 acres of mineral rights.

13. OTHER INCOME (EXPENSE), NET

Other income (expense), net consisted of the following for the fiscal years ended July 31, 2006, 2005 and 2004, respectively:

	Fiscal Year Ended July 31		
	2005	2004	2003
Legal settlement with Colt LLC	$ (2,951,608)	$	$
Gain on sale of investment in HCM	127,416		
Gain on sale of marketable securities trading		42,276	2,454
Distribution from Hite Coalbed Methane, L.L.C.	51,452	6,615	
Other, net	8,297	(13,506)	

	$ (2,764,443)	$ 35,385	$ 2,454

14. OIL AND GAS PROPERTIES

The Company s oil and gas properties are all located in the United States of America and consist solely of its coalbed methane projects in the Illinois Basin. The Company s acreage rights in the Illinois Basin are currently divided into three projects: the Southern Illinois Basin Project; the Northern Illinois Basin Project; and the Western Illinois Basin Project.

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Notes to Consolidated Financial Statements (Continued)

Southern Illinois Basin Project

The Company s CBM rights in the Southern Illinois Basin Project (formerly called the Delta Project) cover approximately 10,000 acres in the southern part of the Illinois Basin. The Company s CBM rights on this acreage previously covered approximately 43,000 acres pursuant to a lease agreement, the primary term of which ended on April 3, 2006. As described in note 12, the lease was subject to litigation during the fiscal year ended July 31, 2006 and the Company reached a settlement with the defendants in the lawsuit, resulting in the Company acquiring ownership of the CBM estate free of any royalty interest covering approximately 10,000 of the 43,000 acres previously covered by the lease (which acreage includes all of the Company s producing CBM wells and proved reserves at our Southern Illinois Basin Project). The Company is still paying two overriding royalty interests of 3% and 4%, both of which are calculated based on 43.35% of gross revenues from the project.

Under the terms of the deed covering this acreage, the Company s right to drill for and produce CBM takes precedence over coal mining operations for as long as CBM is being produced from the acreage. However, the owner of the coal rights has the right to acquire any CBM wells located in these 10,000 acres. If the coal rights owner exercises this option, it will be required to (i) to immediately plug any such well so acquired and (ii) pay the fair market value (as established by a mutually agreed upon expert) of such well.

The Company commenced sales of gas from the initial pilot production wells on this project in January 2005. As of July 31, 2006, the Company had drilled 108 wells at this project. These wells consist of 86 productive wells, 14 shut-in wells, of which eight are scheduled to be plugged in fiscal year 2007 (as a result of the Colt LLC settlement), four plugged wells, one disposal well and three wells that have been drilled but are not yet in production. Most of the wells drilled at this project were initially completed in a limited number of seams, intentionally excluding other seams. The Company s intention when it drilled these wells was to gather as much geological information as it could about CBM and dewatering characteristics of individual coal seams. During the fiscal year ended July 31, 2006, the Company went back and completed additional seams in most of these wells to begin dewatering and producing CBM from the additional seams penetrated by these wells. During fiscal year 2007, we will determine whether it is beneficial to complete additional seams in the remaining wells.

Northern Illinois Basin Project

The Company s CBM rights in the Northern Illinois Basin Project cover 353,531 acres in Montgomery, Shelby, Christian, Fayette and Macoupin Counties in Illinois, which are located in the north central part of the Illinois Basin. The Company holds its CBM rights on this acreage pursuant to mineral leases, an option to acquire a mineral lease and a farm-out agreement. As of July 31, 2006, the Company had drilled 15 wells at this project. These wells consist of a recent 10-well pilot project, one well plugged, one disposal wells and three test wells.

Montgomery County Lease

The lease agreement with Montgomery County covers 120,951 acres of CBM rights in Montgomery County, Illinois. The lease agreement extends until November 27, 2010. After the initial term of the agreement, the Company can continue to hold the lease as long as it is producing CBM from the covered acreage. Under the lease agreement, the Company will be required to pay royalties to the lessor equal to 12.5% of the Company s gross proceeds from the sale of CBM produced from the covered acreage.

Shelby County Lease

The lease agreement with Shelby County covers 63,250 acres of CBM rights in Shelby County, Illinois. This lease agreement extends until November 12, 2008. After the initial term of the agreement, the Company can continue to hold the lease as long as it is producing CBM from the covered acreage, with each productive vertical well holding 320 acres and each productive horizontal well holding 1,920 acres. The Company is required to pay

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Notes to Consolidated Financial Statements (Continued)

royalties to the lessor equal to 12.5% of the Company s gross proceeds from the sale of CBM produced from the covered acreage.

IEC (Montgomery), LLC Lease

The lease agreement with IEC (Montgomery), LLC covers approximately 102,000 acres of CBM rights in Christian, Fayette, Montgomery and Shelby Counties in Illinois. The lease agreement extends until April 26, 2026. After the initial term of the agreement, the Company can continue to hold the lease as to each acreage block where it is producing CBM in commercial quantities. The Company is required to pay royalties to the lessor on the Company s gross proceeds from the sale of CBM produced from the covered acreage at rates ranging up to 12.5%.

Christian Coal Holdings, LLC Lease

The lease agreement with Christian Coal Holdings, LLC covers approximately 12,044 acres of CBM rights in Christian and Montgomery Counties in Illinois. The lease agreement extends until April 26, 2026. After the initial term of the agreement, the Company can continue to hold the lease as to each acreage block where it is producing CBM in commercial quantities. The Company is required to pay royalties to the lessor on the Company s gross proceeds from the sale of CBM produced from the covered acreage at a rate of 12.5%.

Christian County Option

The Company holds an option from Christian County to lease 14,033 acres of CBM rights in Christian County, Illinois. The option extends until January 20, 2007. The lease agreement underlying the option will extend for a period of five years from the date the Company exercises the option. After the initial term of the agreement, the Company can continue to hold the lease as long as it is producing CBM from the covered acreage. Under the lease agreement, the Company will be required to pay royalties to the lessor equal to 12.5% of the Company s gross proceeds from the sale of CBM produced from the covered acreage.

Addington Exploration, LLC (Macoupin County) Farm-out Agreement

Also included in the Northern Illinois Basin Project are 41,253 acres of CBM rights in Macoupin County, Illinois, which the Company can earn under a farm-out agreement with Addington Exploration, LLC, as described in more detail below.

Under the lease agreements with Montgomery and Shelby Counties and the lease agreement underlying the option agreement with Christian County, the Company s right to drill for and produce CBM is expressly subject to the mining of coal on the covered acreage. The Company may not interfere with any existing coal mining operations and, under certain circumstances, may be required to cease drilling in locations where coal mining operations will be undertaken.

Under the lease agreements with IEC (Montgomery), LLC and Christian Coal Holdings, LLC, any drilling operations that the Company sets up can be displaced by coal mining operations. However, the lessor is required to provide the Company with a mine plan for the leased acreage indicating the acreage blocks that the lessor plans to mine and the order of priority for the acreage blocks that it plans to mine. If the lessor displaces a well ahead of the schedule outlined in the mine plan, the lessor may be required to reimburse the Company for the cost of plugging the well and, depending on how long the well has been in production and the cumulative gross income generated by the well, the value of the CBM that could be recovered from the well in the remainder of an eight-year term.

As of July 31, 2006, the Company had just recently completed drilling of a 10-well pilot program at this project, and all wells were in the initial stages of dewatering as of that date. As of the same date, the Company has drilled three test wells at this project. In addition, the Company intends to drill two additional test wells at this project during the first quarter of fiscal year 2007.

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Western Illinois Basin Project

The Company s CBM rights in the Western Illinois Basin Project cover 135,948 acres in Clinton, Washington, Marion and Perry Counties in Illinois, which are located in the northwestern part of the Illinois Basin. The Company holds its CBM rights on this acreage pursuant to mineral leases, an option to acquire a mineral lease and a farm-out agreement.

Clinton County Lease

The lease agreement with Clinton County covers 55,900 acres of CBM rights in Clinton County, Illinois. The lease agreement extends until October 24, 2010. After the initial term of the agreement, the Company can continue to hold the lease as long as it is producing CBM from the covered acreage. The Company is required to pay royalties to the lessor equal to 12.5% of the Company s gross proceeds from the sale of CBM produced from the covered acreage.

Washington County Option

The lease agreement with Washington County covers 39,169 acres of CBM rights in Washington County, Illinois. The lease agreement extends until September 9, 2011. After the initial term of the agreement, the Company can continue to hold the lease as long as it is producing CBM from the covered acreage, with each productive vertical well holding 320 acres and each productive horizontal well holding 1,920 acres. Under the lease agreement, the Company is required to pay royalties to the lessor from the Company s gross proceeds from the sale of CBM produced from the covered acreage. The royalty is equal to 12.5% or 6.25% of the Company s gross proceeds, depending on whether it is determined that Washington Counties CBM rights, if any, are derived from coal rights or oil and gas rights.

Marion County Option

The Company holds an option from Marion County to lease 17,882 acres of CBM rights in Marion County, Illinois. The option extends until June 8, 2007. The lease agreement underlying the option will extend for a period of five years from the date the Company exercises the option. After the initial term of the agreement, the Company can continue to hold the lease as long as it is producing CBM from the covered acreage. Under the lease agreement, the Company will be required to pay royalties to the lessor equal to 12.5% of the Company s gross proceeds from the sale of CBM produced from the covered acreage. If the Company does not commence exploration of CBM within one year from the commencement of the lease, the Company will be required to pay advance royalties to the lessor equal to $8,941 for each one-year period that the Company delays commencing exploration. Any payment of advance royalties can be credited against royalties that may later become payable to the lessor from the production of CBM.

Addington Exploration, LLC (Perry County) Farm-out Agreement

The Company entered into a farm-out agreement with Addington Exploration, LLC covering 41,253 acres of CBM rights in Macoupin County, Illinois (Northern Illinois Basin) and 22,997 acres of CBM rights in Perry County, Illinois (Western Illinois Basin) that Addington controls pursuant to coal seam gas leases. The farm-out agreement provides for an initial 36-month evaluation period, during which the Company may test and evaluate the covered properties. The 36-month evaluation period can be extended by the Company on unearned acreage through the payment of a fee equal to $0.50 per acre, increasing over five years to $2.50 per acre. For each vertical and horizontal well that the Company places into production during the term of the agreement, Addington will assign to the Company its CBM rights covering the surrounding 160 acres penetrated by one of the Company s wells. The Company is required to pay

Addington a royalty equal to 3% of the Company s proceeds from the sale of CBM produced from the covered acreage. In addition, the Company must pay royalties totaling 12.5% to the lessors under the coal seam gas leases underlying this farm-out agreement.

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Under the lease agreement with Washington County and the lease agreement underlying the option agreement with Marion County, the Company s right to drill for and produce CBM is expressly subject to the mining of coal on the covered acreage. The Company may not interfere with any existing coal mining operations and, under certain circumstances, may be required to cease drilling in locations where coal mining operations will be undertaken. Under the lease agreement with Clinton County, coal mining rights granted to third parties do not take precedence over the Company s CBM operations.

As of July 31, 2006, the Company has drilled two test wells at the Western Illinois Basin Project. The Company intends to drill three test wells at this project during the first quarter of fiscal year 2007.

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

	Total	2006	2005	2004	2003 and Prior
Property acquisition costs	$ 178,072	$	$ 150,771	$ 27,301	$
Exploration and development, net of transfers to proved oil and gas properties	3,190,159	2,445,674	742,005	2,480	
	$ 3,368,231	$ 2,445,674	$ 892,776	$ 29,781	$

No interest has been capitalized and included in the cost of unproved properties as of July 31, 2003 or in the fiscal years ended July 31, 2006, 2005 and 2004, as such amounts were not material. The Company expects to include the costs associated with unproved properties in its amortization computation over the next one to three years when future development of the projects is expected to result in additional reserves being classified as proved. Depletion expense related to proved oil and gas properties was $331,150, $58,523 and $0 or $2.28/Mcf, $1.72/Mcf and $0/Mcf in the fiscal years ended July 31, 2006, 2005 and 2004, respectively.

15. RELATED PARTY TRANSACTIONS

The Company enters into various transactions with related parties in the normal course of business operations.

Randy Oestreich, the Company s Vice President of Field Operations, owns and operates A-Strike Consulting, a consulting company that provides, among other things, laboratory testing related to coalbed methane. Beginning in fiscal year ended July 31, 2005, the Company owns and maintains a lab testing facility and allows A-Strike Consulting to operate the facility. The Company pays all expenses related to the facility and, in return, receives 80% of the revenue generated from the operations of the facility as reimbursement of the Company s expenses. The Company received approximately $70,000, $59,000 and $0 in expense reimbursement related to this arrangement during the fiscal years ended July 31, 2006, 2005 and 2004, respectively. Mr. Oestreich s brother owns Dependable Service Company, a company that provides general labor services to the Company. The Company paid Dependable

Services Company approximately $237,000, $147,000 and $16,000 during the fiscal years ended July 31, 2006, 2005 and 2004, respectively.

David Preng, a director of the Company owns Preng & Associates, an executive search firm specializing in the energy and natural resources industries. The Company paid Preng & Associates approximately $293,000, $0 and $0 for executive placement services during the fiscal years ended July 31, 2006, 2005 and 2004, respectively.

16. SUBSEQUENT EVENTS

Officer Resignation

On October 10, 2006, the Company entered into a Separation Agreement and Waiver and Release (Separation Agreement) with George Zilich, the Company s Chief Financial Officer and General Counsel. Under the terms of

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Notes to Consolidated Financial Statements (Continued)

the Separation Agreement, Mr. Zilich resigned as an employee, officer and director of the Company effective immediately and the Company will provide consideration to Mr. Zilich for entering into the Separation Agreement as follows:

In connection with Mr. Zilich s existing employment agreement, the Company is required to make a cash payment to Mr. Zilich in the amount of $250,000 within three business days of his resignation. Such amount will be recorded as compensation expense during the first quarter of fiscal year 2007.

In connection with Mr. Zilich s existing employment agreement, provide medical and dental insurance coverage to Mr. Zilich through the second anniversary of the separation date. The Company will pay all premiums for such insurance coverage; provided, however, that if, at any time prior to the second anniversary of the separation date, Mr. Zilich becomes eligible to participate in an employer sponsored and fully paid medical and dental insurance plan or policy with comparable coverage, the Company s obligation to provide such coverage will terminate effective as of the date that Mr. Zilich becomes eligible to enroll in such plan or policy. Such amounts incurred for the premiums will be charged to expense as incurred in the future.

In connection with a continuing services clause of the Separation Agreement, the Company is required to issue 40,000 unrestricted common shares to Mr. Zilich within three business days of his resignation and make cash payments to Mr. Zilich in the amount of $8,333.33 on each of the following dates: October 15, 2006; October 31, 2006; November 15, 2006; November 30, 2006; December 15, 2006; and December 31, 2006. In return, Mr. Zilich will provide the Company with consulting services as may be reasonably requested by the Company from time to time through January 2, 2008. The Company will recognize the expense related to these payments over the future period(s) in which it expects to receive consulting services from Mr. Zilich.

In connection with a non-compete and non-solicitation clause of the Separation Agreement, the Company is required to make payments to Mr. Zilich in the amount of $100,000 on each of the following dates: January 2, 2007; August 1, 2007; and January 2, 2008. The Company is also required to take actions to provide that the 380,720 restricted common shares currently held by Mr. Zilich vest immediately on the separation date. In return, Mr. Zilich agrees not to (a) engage, either directly or indirectly, as an employee, officer or partner in a business that is competitive with the Company s coal bed methane gas extraction business in the geographical territory known as the Illinois Basin, or (b) solicit or attempt to solicit, either on Zilich s behalf or on behalf of any of third party, or assist any third party in soliciting, any employee of the Company to leave or terminate their employment with the Company. The Company will recognize expense related to these payments over the future period(s) in which it expects to benefit from the terms of this agreement.

New Technical Staff Compensation

During the first quarter of fiscal year 2007, the Company added four new members to its technical team: a Geologist and three Engineers. As an inducement to join the Company, the Company paid the new employees a total of $345,000 in signing bonuses and granted them a total of 350,000 shares of unrestricted stock (James Erlandson 90,000; Michael Dawson 100,000; Bradford Sutton 80,000; and Kelly Sutton 80,000) and 700,000 shares of restricted stock (James Erlandson 180,000; Michael Dawson 200,000; Bradford Sutton 160,000; and Kelly Sutton 160,000). These share grants were made outside the Omnibus Stock Plan in accordance with AMEX Company Guide Rule 711. The shares of restricted stock will vest based on service over a two-year period. In addition, the total annual salaries of these new employees will be $600,000.

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17. SUPPLEMENTAL GAS DATA (UNAUDITED)

The following unaudited information was prepared in accordance with Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities and related accounting rules.

The following summaries of changes in reserves and standardized measure of discounted future net cash flows were prepared from estimates of proved reserves developed by our independent reservoir engineer consultant.

Summary of Changes in Proved Reserves

	Year Ended July 31		
	2006 MMcf	**2005 MMcf**	**2004 MMcf**
Proved reserves			
Beginning of year	10,292		
Purchase of reserves in place	2,229		
Extensions and discoveries	4,528	10,326	
Revisions of previous estimates	(2,186)		
Production	(145)	(34)	
End of year	14,718	10,292	
Proved developed reserves			
Beginning of year	2,971		
End of year	8,983	2,971	

Capitalized Costs Related to Gas Producing Activities

The capitalized costs relating to gas producing activities and the related accumulated depletion, depreciation and accretion as of July 31, 2006 and 2005 were as follows:

	Fiscal Year Ended July 31	
	2006	**2005**
Capitalized costs:		
Proved oil and gas properties	$ 21,098,048	$ 10,248,652
Unproved oil and gas properties	3,368,231	3,149,372
Support equipment	1,046,989	760,467
Gas collection	4,342,400	1,332,012
Total capitalized costs	29,855,668	15,490,503

Less: Accumulated DD&A	(922,534)	(426,485)
Net capitalized costs	$ 28,933,134	$ 15,064,018

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Costs Incurred in Gas Exploration and Development Activities

Costs related to gas activities of the Company were incurred as follows for the fiscal years ended July 31, 2006, 2005 and 2004:

	Fiscal Year Ended July 31		
	2006	**2005**	**2004**
Property acquisition proved	$	$	$
Property acquisition unproved		341,634	2,664
Exploration		743,811	1,778,517
Development	11,007,725	5,541,022	
Support equipment	286,522	238,153	201,643
Gas collection	3,010,388	1,225,113	106,899
	$ 14,304,635	$ 8,089,733	$ 2,089,723

Prior to fiscal year 2005, the Company s properties were all considered unproved and all costs to drill and equip wells and gain access to and prepare well locations for drilling were classified as exploration costs.

Results of Operations from Gas Producing Activities

The table below sets forth the Company s results of operations from gas producing activities for the fiscal years ended July 31, 2006, 2005 and 2004. The Company commenced production and sales of gas during fiscal year ended July 31, 2005. The Company had no revenues or operating expenses of gas activities during the fiscal year ended July 31, 2004.

	Fiscal Year Ended July 31		
	2006	**2005**	**2004**
Gas revenues	$ 1,126,477	$ 117,835	$
Production costs	(970,791)	(307,178)	
Depreciation, depletion and amortization	(538,055)	(238,366)	
Pre-tax operating loss	(382,369)	(427,709)	
Income taxes		166,807	
Loss from oil and gas producing activities	$ (382,369)	$ (260,902)	$

The following estimates of proved reserve quantities and related standardized measure of discounted net cash flows are estimates only and do not purport to reflect realizable values or fair market values of the Company s reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing gas properties. Accordingly, these estimates are expected to change as future information becomes available. All of the Company s reserves are located in the United States.

Proved reserves are estimated reserves of crude oil (including condensate and natural gas liquids) and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those expected to be recovered through existing wells, equipment and operating methods.

The standardized measure of discounted future net cash flows is computed by applying year-end prices of gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year-end statutory tax rates, with consideration of future tax rates already legislated) to be incurred on pretax net cash flows

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Notes to Consolidated Financial Statements (Continued)

less tax basis of the properties and available credits, and assuming continuation of existing economic conditions. The estimated future net cash flows are then discounted using a rate of 10% per year to reflect the estimated timing of the future cash flows. The average net price per Mcf used at July 31, 2006 and 2005 was $7.22 and $7.44, respectively.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Gas Reserves

The standardized measure of discounted cash flows related to proved gas reserves at July 31, 2006, 2005 and 2004 were as follows:

	July 31		
	2006	2005	2004
	(Amounts in thousands)		
Future cash inflows	$ 106,221	$ 76,608	$
Future production costs and taxes	(24,937)	(10,181)	
Future development costs	(8,930)	(7,824)	
Future income tax expenses	(15,775)	(14,663)	
Net future cash flows	56,579	43,940	
Discounted at 10% for estimated timing of cash flows	(23,845)	(20,872)	
Standardized measure of discounted future net cash flows	$ 32,734	$ 23,068	$

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Gas Reserves

The primary changes in the standardized measure of discounted future net cash flows for the fiscal years ended July 31, 2006, 2005 and 2004 were as follows:

	Year Ended July 31		
	2006	2005	2004
	(Amounts in thousands)		
Standardized measure, beginning of year	$ 23,068	$	$
Sales, net of production costs and taxes	(156)	189	
Extensions and discoveries	14,633	27,758	
Purchases of reserves in place	7,206		
Net changes in prices and production costs	(5,606)		
Net changes in future development costs	(1,023)	(5,541)	
Revisions of quantity estimates	(7,063)		
Interest factor accretion of discount	3,077		
Net change in income tax	(651)		

Net change in production rates (timing) and other	(751)	662	
Net increase	9,666	23,068	
Standardized measure, end of year	$ 32,734	$ 23,068	$

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Notes to Consolidated Financial Statements (Continued)

18. SELECTED QUARTERLY DATA (UNAUDITED)

Summarized below are the unaudited results of operations by quarter for fiscal years ended July 31, 2006 and 2005:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Fiscal 2006:				
Gas sales	$ 209,694	$ 327,811	$ 262,860	$ 326,112
Lease operating expenses	160,804	300,806	290,844	218,337
Net loss	(1,193,261)	(854,225)	(4,941,588)	(1,847,171)
Basic and diluted loss per common share	$ (.03)	$ (.01)	$ (.14)	$ (.03)
Fiscal 2005:				
Gas sales	$	$ 6,341	$ 46,925	$ 64,569
Lease operating expenses			203,289	103,889
Net loss	(388,347)	(2,485,843)	(1,734,199)	(787,962)
Basic and diluted loss per common share	$ (.01)	$ (.07)	$ (.04)	$ (.02)

Prospectus Supplement
to Separate Prospectuses dated
May 11, 2006