BPI Energy Holdings, Inc.
Form 10-Q
June 13, 2007

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

FORM 10-Q
QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended April 30, 2007
Commission File No. 001-32695

BPI Energy Holdings, Inc.
(Exact Name of Registrant as Specified in Its Charter)

British Columbia, Canada	**75-3183021**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
30775 Bainbridge Road, Suite 280, Solon, Ohio	**44139**
(Address of Principal Executive Offices)	(Zip Code)

Registrant s telephone number, including area code: **(440) 248-4200**

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

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

Large accelerated filer o Accelerated filer o Non-accelerated filer þ

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date: Common Shares, without par value, as of June 8, 2007: 72,524,493.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

BPI Energy Holdings, Inc.
Consolidated Balance Sheets

	April 30, 2007 (Unaudited)	July 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,070,656	$ 19,279,015
Accounts receivable	130,426	105,711
Other current assets	618,937	164,764
Total current assets	7,820,019	19,549,490
Property and equipment, at cost:		
Gas properties, full cost method of accounting:		
Proved, net of accumulated depreciation, depletion and amortization of $734,814 and $375,000	26,326,432	25,065,448
Unproved	7,115,629	3,368,231
Net gas properties	33,442,061	28,433,679
Other property and equipment, net of accumulated depreciation and amortization of $818,626 and $587,165	1,683,231	807,686
Net property and equipment	35,125,292	29,241,365
Restricted cash	100,000	100,000
Other non-current assets	294,447	161,125
Total assets	$ 43,339,758	$ 49,051,980
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 984,802	$ 1,492,239
Current maturity of long-term notes payable	29,135	140,866
Accrued liabilities and other	856,696	649,237
Total current liabilities	1,870,633	2,282,342
Long-term notes payable, less current portion	54,325	75,149
Asset retirement obligation	111,020	70,754
Total liabilities	2,035,978	2,428,245
Shareholders equity:		
Common shares, no par value, authorized 200,000,000 shares, 72,524,493 and 70,812,540 outstanding	67,946,143	67,946,143
Additional paid-in capital	7,145,431	5,871,120
Accumulated deficit	(33,787,794)	(27,193,528)
Total shareholders equity	41,303,780	46,623,735

Total liabilities and shareholders equity	$ 43,339,758	$ 49,051,980

See Notes to Unaudited Consolidated Financial Statements.

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BPI Energy Holdings, Inc.
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended April 30,		Nine Months Ended April 30,	
	2007	**2006**	**2007**	**2006**
Revenues:				
Gas sales	$ 334,706	$ 262,860	$ 875,615	$ 800,365
Expenses:				
Lease operating expense	411,938	290,844	1,275,685	752,454
General and administrative expenses	1,885,061	2,054,434	6,089,287	4,491,676
Depreciation, depletion and amortization	215,280	189,988	591,275	402,680
Total operating expenses	2,512,279	2,535,266	7,956,247	5,646,810
Operating loss	(2,177,573)	(2,272,406)	(7,080,632)	(4,846,445)
Other income (expenses):				
Interest income	108,660	229,888	493,982	632,693
Interest expense	(1,437)	(4,276)	(7,616)	(18,054)
Other income (expense)		(2,894,794)		(2,757,271)
	107,223	(2,669,182)	486,366	(2,142,632)
Net loss	$ (2,070,350)	$ (4,941,588)	$ (6,594,266)	$ (6,989,077)
Basic and diluted loss per share	$ (0.03)	$ (0.07)	$ (0.09)	$ (0.12)
Weighted average common shares outstanding	70,036,326	66,395,782	69,642,804	60,686,413

See Notes to Unaudited Consolidated Financial Statements.

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BPI Energy Holdings, Inc.
Consolidated Statements of Shareholders   Equity
(Unaudited)

	Common Shares		Additional Paid-in	Accumulated	Total Shareholders
	Shares	Amount	Capital	Deficit	Equity
Balance at July 31, 2006	70,812,540	$ 67,946,143	$ 5,871,120	$ (27,193,528)	$ 46,623,735
Share-based payments common shares, including vesting of restricted shares	1,795,883		1,317,115		1,317,115
Surrender of shares	(83,930)		(42,804)		(42,804)
Net loss				(6,594,266)	(6,594,266)
Balance at April 30, 2007	72,524,493	$ 67,946,143	$ 7,145,431	$ (33,787,794)	$ 41,303,780

See Notes to Unaudited Consolidated Financial Statements.

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BPI Energy Holdings, Inc.
Consolidated Statements of Cash Flows
(Unaudited)

	Nine Months Ended April 30, 2007	2006
Operating activities:		
Net loss	$ (6,594,266)	$ (6,989,077)
Adjustments to reconcile net loss to net cash used in operating activities:		
Depreciation, depletion and amortization	591,275	402,680
Share-based payments	1,045,879	1,044,847
Gain on sale of investment		(127,416)
Accretion of asset retirement obligation	5,197	2,464
Changes in assets and liabilities:		
Accounts receivable	(24,715)	(91,431)
Other current assets	(159,063)	(201,490)
Accounts payable	(152,231)	(374,117)
Accrued liabilities and other	7,459	3,038,378
Other assets and liabilities		49,214
Net cash used in operating activities	(5,280,465)	(3,245,948)
Investing activities:		
Proceeds from sale of investment		551,000
Additions to property and equipment	(6,795,339)	(12,902,470)
Increase in restricted cash		(34,173)
Net cash used in investment activities	(6,795,339)	(12,385,643)
Financing activities:		
Payments on long-term notes payable	(132,555)	(106,306)
Net proceeds from issuance of common shares		33,280,121
Net cash (used in) provided by financing activities	(132,555)	33,173,815
Net (decrease) increase in cash and cash equivalents	(12,208,359)	17,542,224
Cash and cash equivalents at the beginning of the period	19,279,015	7,251,503
Cash and cash equivalents at the end of the period	$ 7,070,656	$ 24,793,727
Supplementary disclosure of cash flow information:		
Cash payments:		
Interest paid	$ 6,616	$ 14,132
Non-cash investing activities acquisition of equipment by issuance of notes payable		233,475

See Notes to Unaudited Consolidated Financial Statements.

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BPI Energy Holdings, Inc.
Notes to Consolidated Financial Statements
(Unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These unaudited consolidated interim financial statements include the accounts of BPI Energy Holdings, Inc. and its wholly owned U.S. subsidiary, BPI Energy, Inc. (collectively, the Company). 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 in the Illinois Basin. The Company conducts its operations in one reportable segment, which is gas exploration and production. The Company s common shares trade on the American Stock Exchange under the symbol BPG. Amounts shown are in U.S. Dollars unless otherwise indicated.

The accompanying unaudited consolidated financial statements have been prepared in accordance with generally accepted accounting principles for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included. Operating results for the three and nine months ended April 30, 2007 are not necessarily indicative of the results that may be expected for the full fiscal year. For further information, refer to the consolidated financial statements and notes thereto included in the Company s Annual Report on Form 10-K for the fiscal year ended July 31, 2006. Certain prior period amounts have been reclassified to conform to the current period s presentation.

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 unaudited 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 gas properties and the impairment of gas properties are determined using estimates of 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 asset retirement obligations. Gas reserve engineering must be recognized as a subjective process of estimating underground accumulations of gas that cannot be measured in an exact way. Proved reserves of 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.

Gas Properties

The Company follows the full cost method of accounting for gas properties. Under this method, all costs associated with the acquisition of, exploration for and development of 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 gas activities that are not directly attributable to acquisition, exploration or development activities are expensed as incurred.

Unproved 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 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.

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Capitalized costs of proved 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 the end of each reporting period.

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; or

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

No impairment existed as of April 30, 2007 or July 31, 2006.

Other Property and Equipment

Other property and equipment is stated at cost and includes support equipment used in gas operations and other fixed assets such as office equipment, computer hardware and software, and furniture and fixtures. Other property and equipment are depreciated using the straight-line method over the estimated useful lives of the assets, ranging from three to 10 years. Major classes of other property and equipment consisted of the following at April 30, 2007 and July 31, 2006, respectively:

	April 30, 2007	July 31, 2006
Other property and equipment:		
Support equipment	$ 1,832,445	$ 1,046,989
Other	669,412	347,862
Less: Accumulated depreciation and amortization	(818,626)	(587,165)
	$ 1,683,231	$ 807,686

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 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. The following items were excluded from the computation of diluted loss per share at April 30, 2007 and 2006, respectively, as the effect of their assumed exercises would be anti-dilutive:

	April 30, 2007	April 30, 2006
Outstanding warrants	5,311,600	5,311,600
Outstanding stock options	1,529,931	1,872,812
Nonvested portion of restricted shares issued	2,437,338	2,184,498
	9,278,869	9,368,910

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2. STOCK-BASED COMPENSATION

SFAS No. 123 (R)

In December 2004, the FASB issued Statement of Financial Accounting Standards (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 nonvested portion of previous stock option grants that vested during the fiscal year ended July 31, 2006 or thereafter. Therefore, the adoption of SFAS 123(R) had no impact on the Company s consolidated financial position or results of operations for the periods presented. The Company uses the Black-Scholes formula to estimate the fair value of stock options granted.

Incentive Stock Option Plan

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 shares 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 following table summarizes information about options outstanding under the Incentive Stock Option Plan at April 30, 2007.

Exercise Price (CAD$)	**Number Outstanding**	**Remaining Life (Years)**	**Expiry Date**
$ 0.65	345,000	1.8	November 3, 2008
0.90	10,000	2.6	September 22, 2009
1.49	695,666	2.8	November 29, 2009
2.05	10,000	3.6	September 22, 2010
2.19	136,000	3.2	March 27, 2010
2.40	333,265	3.0	January 20, 2010
$ 1.56	1,529,931	2.4	

Omnibus Stock Plan

On December 13, 2005, the shareholders of the Company approved the Company s 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 until December 13, 2010. 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.

The Omnibus Stock Plan provides that in any fiscal year of the plan the Company may grant awards with respect to up to 5% of the number of common shares outstanding as of the first day of that fiscal year plus the number of common shares that were available for the grant of awards, but not granted, in prior years under the plan. In no event, however, may the number of common

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shares available for the grant of awards in any fiscal year exceed 6% of the common shares outstanding as of the first day of that fiscal year. In addition, the aggregate number of common shares that could be issued under the Omnibus Stock Plan is capped at 7,000,000. As of April 30, 2007, the Company has issued 2,532,338 restricted common shares and 388,662 unrestricted common shares (but no options) under the Omnibus Stock Plan and has 4,079,000 common shares available for future issuance under the Plan.

Share-Based Transactions

The following table summarizes the Company s restricted share activity during the three and nine months ended April 30, 2007:

	Shares	Weighted Avg. Grant Date Fair Value
Nonvested at July 31, 2006	2,325,000	$ 0.61
Granted	1,207,338	0.78
Vested	(475,000)	0.49
Nonvested at October 31, 2006	3,057,338	0.70
Vested	(520,000)	1.42
Nonvested at January 31, 2007	2,537,338	0.74
Vested	(100,000)	1.42
Nonvested at April 30, 2007	2,437,338	$ 0.71

All restricted share 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 restricted shares scheduled to vest on the next vesting date, based on the number of days continuously employed during the applicable vesting period. The Company includes all restricted shares 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 share grants upon receiving approval from the American Stock Exchange, when required, for the issuance of such shares.

As of April 30, 2007, there was $1,361,087 of unrecognized compensation cost related to restricted shares. The cost is expected to be amortized over a weighted average period of 1.1 years. The amount charged to expense related to restricted shares was $211,381 and $718,059 during the three and nine months ended April 30, 2007, respectively, and $22,461 during both the three and nine months ended April 30, 2006.

3. OTHER ASSETS

Other Current Assets

Other current assets consisted of the following at April 30, 2007 and July 31, 2006, respectively:

	April 30, 2007	July 31, 2006
Separation agreement	$ 337,949	$
Prepaid expenses and other	280,988	164,764
	$ 618,937	$ 164,764

Other Non-current Assets

Other non-current assets consisted of the following at April 30, 2007 and July 31, 2006, respectively:

	April 30, 2007	**July 31, 2006**
Separation agreement	$ 133,322	$
Advance royalties	161,125	161,125
	$ 294,447	$ 161,125

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Prepaid expenses primarily represent amounts paid one year in advance for commercial insurance premiums and monthly prepayments of rent, health benefits and other expenses. The separation agreement represents amounts capitalized related to non-compete/non-solicitation and continuing services clauses contained in a separation agreement entered into with a former officer of the Company on October 12, 2006. See note 10 for further explanation of this agreement.

4. ACCRUED LIABILITIES AND OTHER

Accrued liabilities and other consisted of the following at April 30, 2007 and July 31, 2006, respectively:

	April 30, 2007	July 31, 2006
Employee compensation	$ 565,000	$ 467,869
Separation agreement	200,000	
Professional and regulatory	40,696	111,805
Directors fees	40,000	31,000
Other	11,000	38,563
	$ 856,696	$ 649,237

The separation agreement represents amounts due related to non-compete/non-solicitation and continuing services clauses contained in a separation agreement entered into with a former officer of the Company on October 12, 2006. See note 10 for further explanation of this agreement.

5. LONG-TERM NOTES PAYABLE

Long-term notes payable consisted of the following at April 30, 2007 and July 31, 2006, respectively:

	April 30, 2007	July 31, 2006
Case Credit term note due in fiscal year 2006, 6.50%	$ 1,579	$ 15,410
GMAC term note due in fiscal year 2009, 6.50%	15,827	20,608
GMAC term notes due in fiscal year 2010, 6.1% to 6.50%	66,054	80,849
Caterpillar Financial Services term note due in fiscal year 2007, 7.0%		99,148
	83,460	216,015
Less current maturities	(29,135)	(140,866)
Long-term notes payable	$ 54,325	$ 75,149

The notes are collateralized by the related vehicles and equipment.

6. ASSET RETIREMENT OBLIGATIONS

The Company follows 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 Company s asset retirement obligations relate to the plugging of wells upon exhaustion of gas reserves.

The following table summarizes the activity for the Company s asset retirement obligation for the nine months ended April 30, 2007 and 2006, respectively:

Nine Months Ended

	April 30,	
	2007	2006
Beginning asset retirement obligation	$ 70,753	$ 19,778
Additional liability incurred	18,893	29,436
Accretion expense	5,197	2,464
Change in estimate	35,377	
Asset retirement costs incurred	(36,239)	
Loss on settlement of liability	17,039	
Ending asset retirement obligation	$ 111,020	$ 51,678

During the nine months ended April 30, 2007, the Company incurred $36,239 related to plugging wells in conjunction with the legal settlement reached with Colt LLC in fiscal year 2006. The actual cost of plugging the wells exceeded the Company s estimate, resulting in a loss on settlement of the liability of $17,039. The Company changed its estimate of future costs associated with plugging wells, resulting in an increase to the asset retirement obligation of $35,377, which was recorded in the second quarter of fiscal year 2007.

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

8. INCOME TAXES

The Company operates in two tax jurisdictions, the United States and Canada. Primarily as a result of the net operating losses that the Company has generated (NOL Carryforwards) in both Canada and the United States, the Company has generated deferred tax benefits available for tax purposes to offset net income in future periods. SFAS No. 109, Accounting for Income Taxes requires that the Company record a valuation allowance when it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of sufficient future taxable income before the expiration of the NOL Carryforwards. Because of the Company s limited operating history, limited financial performance and cumulative tax loss from inception, it is management s judgment that SFAS No. 109 requires the recording of a full valuation allowance for net deferred tax assets in both Canada and the United States as of April 30, 2007.

9. SHAREHOLDERS EQUITY

Common shares The Company has authorized 200,000,000 shares without par value of which 72,524,493 and 70,812,540 were issued and outstanding as of April 30, 2007 and July 31, 2006, respectively. Shares issued and outstanding at April 30, 2007 include 2,437,338 of restricted shares expected to vest in future periods.

Additional paid-in capital Amounts recorded of $7,145,431 and $5,871,120 at April 30, 2007 and July 31, 2006, respectively, represent the cumulative value of share-based payments made as of each date.

Share purchase warrants outstanding at April 30, 2007 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		

10. SEPARATION AGREEMENT

On October 12, 2006, the Company entered into a Separation Agreement and Waiver and Release (Separation Agreement) with a former officer and director of the Company. Under the terms of the Separation Agreement, the Company agreed to provide consideration to the former officer and director upon his resignation as follows:

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Severance cash payment of $250,000 and medical and dental insurance coverage for two years from the date of the agreement. The cash payment of $250,000 was expensed during the first quarter of fiscal year 2007 and the cost of medical and dental coverage is being expensed as incurred.

Consulting issuance of 40,000 unrestricted common shares and cash payments totaling $50,000 in periodic installments from October 15, 2006 through December 31, 2006 in return for consulting services to be provided by the former officer and director as may be reasonably requested by the Company from time to time through January 2, 2008.

Non-compete/Non-solicitation cash payments of $100,000 on each of three dates from January 2, 2007 through January 2, 2008 and immediate vesting of 475,000 restricted shares held by the former officer and director in return for his agreeing not to compete with the Company or to solicit any of its employees for a period of two years.

The Company capitalized the value of the expected future benefit to be received from both the consulting services and the non-compete/non-solicitation agreement and is amortizing the related expense ratably over the future periods in which it expects to receive the related benefits. As of April 30, 2007, $471,271 of amortized value related to the consulting services and the non-compete/non-solicitation agreement are recorded as other assets on the balance sheet, including $337,949 shown as current and representing the amount to be amortized over the next year. As of April 30, 2007, $200,000 is recorded as a current liability reflecting payments due under the non-compete/non-solicitation agreement within the next year. During the three and nine months ended April 30, 2007, the Company expensed $87,125 and $195,786, respectively, in connection with the consulting services and the non-compete/non-solicitation agreement.

11. 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. 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 $11,708 and $68,674 in expense reimbursement related to this arrangement during the nine months ended April 30, 2007 and 2006, respectively. Mr. Oestreich s brother owns Dependable Service Company, a company that previously provided general labor services to the Company. The Company paid Dependable Services Company $0 and $227,626 during the nine months ended April 30, 2007 and 2006, 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 $12,575 and $150,000 for executive placement services during the nine months ended April 30, 2007 and 2006, respectively.

12. LEGAL PROCEEDINGS

Drummond Coal Co. Litigation

BPI Energy, Inc. (BPI) is currently subject to litigation with respect to approximately 115,000 acres of its CBM rights that are located at the Northern Illinois Basin Project. To date, BPI has drilled one well on this acreage, a test well that was drilled in September 2006. This well is not currently at the production stage.

In 2004, BPI and affiliates of the Drummond Coal Co. (Drummond), including IEC (Montgomery), LLC (IEC), entered into a letter of intent to obtain coal and CBM gas rights for one another in the Illinois Basin and to work together in a relationship in which BPI would extract CBM from coal beds prior to the Drummond affiliates mining of coal from those beds. Pursuant to and in reliance upon this letter of intent and its relationship with Drummond, BPI arranged for the transfer of 163,109 acres of coal rights to the Drummond affiliates for a total purchase price of $5,845,500, which BPI believes reflects a significant discount to current market prices. In light of its obligations to Drummond, BPI charged no profit on its transfer of the coal rights to the Drummond affiliates. Rather, in consideration for obtaining those coal rights, the Drummond affiliates were to lease approximately 115,000 acres of

CBM rights to BPI for a primary lease term of 20 years and with favorable royalty rates. Although the Drummond affiliates entered into two CBM leases with BPI on April 26, 2006, they have since sought in various ways to void or terminate the leases.

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Ignoring mandatory arbitration provisions in the CBM leases, Drummond affiliates IEC and Christian Coal Holdings, LLC (Christian) filed suit against BPI on February 9, 2007 in the United States District Court for the Northern District of Alabama, claiming that BPI has breached the CBM leases in various ways. Specifically, although the CBM leases include no specific drilling commitments, IEC and Christian allege that BPI has breached the CBM leases by failing to use best efforts to commercially produce all economically recoverable gas. IEC and Christian also allege that BPI has breached the CBM leases by failing to provide maps of existing and proposed gas wells and facilities every six months and failing to maintain required insurance coverage. BPI refutes each of these allegations and intends to vigorously defend the Drummond affiliates claims of breach. In addition, BPI moved to dismiss the lawsuit for lack of standing, lack of personal jurisdiction and improper venue, or in the alternative to transfer the case to either Ohio or Illinois.

BPI also moved the court to stay or dismiss the Alabama lawsuit and to compel arbitration under the CBM leases. On May 14, 2007, the Court granted BPI s motion to dismiss on the ground of improper venue. BPI anticipates that IEC and Christian may appeal the decision, move the Court to reconsider it, or reinstitute litigation in a different venue.

On March 13, 2007, BPI filed suit against IEC, Christian and additional Drummond affiliates Shelby Coal Holdings, LLC, Clinton Coal Holdings, LLC and Marion Coal Holdings, LLC in the United States District Court for the Southern District of Illinois. At the court s direction, BPI filed an amended complaint on April 13, 2007. In its lawsuit, BPI seeks to rescind its transfers of coal rights to the Drummond affiliates for failure of consideration due to the Drummond affiliates efforts to avoid the CBM leases, and has also asserted claims for money damages for breach of contract, breach of fiduciary duty, unjust enrichment and promissory estoppel. The defendants filed a motion to dismiss the amended complaint, to which BPI currently is preparing a response.

The Company believes that Drummond and its affiliates, after having received favorable coal rights in exchange for favorable CBM rights, now wish to obtain a significant windfall by seeking to renege on the CBM rights that they were obligated to grant to BPI.

If the Drummond affiliates reinstitute their claims against BPI, the Company believes that it will be successful in defending against their claims of breach. However, there can be no assurance that the Company will be successful in maintaining these acreage rights. The loss of these acreage rights would not have a material impact on the Company s financial position, results of operations or cash flows.

ICG Litigation

In November 2004, BPI entered into a farmout agreement under which it acquired the right to develop certain CBM in Macoupin and Perry counties in Illinois. The farmout agreement covers 41,253 acres of CBM rights in Macoupin County and 22,997 acres of CBM rights in Perry County. The farmor was Addington Exploration, LLC, which leased the CBM rights from Meadowlark Farms, Inc. and Ayrshire Land Company. Meadowlark and Ayrshire went into bankruptcy, and ICG Natural Resources, LLC purchased their assets, including the CBM rights underlying the Addington leases. On April 9, 2007, ICG filed suit against BPI in Perry County, Illinois, in an effort to avoid the Addington leases, claiming that there was a lack of consideration at the time they were originally entered into. BPI has filed a motion to dismiss the lawsuit under the doctrine of estoppel by deed, arguing that ICG cannot challenge the leases because it acquired the CBM rights subject to those leases, as set forth in the deed from Addington and Meadowlark to ICG, the purchase agreement between those parties, and numerous bankruptcy court filings and orders associated with the approval of the sale. Addington was subsequently acquired by Nytis Exploration Company, LLC, which has intervened in the action and joined in BPI s motion. To date, BPI has drilled 10 pilot wells, one pressure observation well and one water disposal well on the acreage covered by the farmout agreement.

The Company believes that it will be successful in either having the case dismissed or in defending against ICG s claims. However, there can be no assurance that the Company will be successful in retaining the acreage rights under this farmout agreement.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The discussion and analysis that follows should be read together with the accompanying unaudited consolidated financial statements and notes related thereto that are included under Item 1.

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), which encompasses a total area of approximately 60,000 square miles covering the southern two-thirds of Illinois, southwestern Indiana and northwestern Kentucky. 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 April 30, 2007, 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 (98% of this acreage is undeveloped as of April 30, 2007). Portions of our CBM rights are currently subject to litigation, as described in Item 1 of Part II below. 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 four millidarcies.

The State of Illinois (which includes most of the Basin) is estimated to be the number two state in the United States in terms of coal reserves; however, coal in the Basin is high in sulfur, discouraging coal mining operations. Recent advances in technology that can utilize higher sulfur 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 Basin. We believe our position as a 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. Net gas sales during the fiscal year ended July 31, 2005 were $117,835 on sales volume of 17,885 Mcf. Net gas sales were $1,126,477 on sales volume of 135,118 Mcf for the fiscal year ended July 31, 2006, an increase of 856% in net gas sales and 655% in sales volume over the prior year. Net gas sales for the current quarter were $330,748 on sales volume of 48,558 Mcf, compared to net gas sales of $262,860 on sales volume of 35,868 Mcf in the same prior year quarter, representing an increase of 26% in net gas sales and an increase of 35% in sales volume. Net gas sales and sales volume for the quarter ended April 30, 2007 also increased 30% and 34%, respectively, over the previous quarter. As previously disclosed, net gas sales in the second quarter of fiscal year 2007 were adversely affected by a nitrogen-related pipeline curtailment that began in October and necessitated six days of downtime followed by a period of constrained sales volume. A nitrogen-rejection unit was installed during the current quarter, with start-up occurring during March 2007.

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, our Chief Operating Officer. Prior to joining us, Mr. Craddock was with Burlington Resources for over 20 years, last serving as Chief Engineer. Mr. Craddock has built a strong in-house technical team, 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 us.

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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. During the current quarter we announced our decision to continue production activities at our Shelby CBM pilot in the Northern Illinois Basin, while deferring additional development pending further production and pressure information. We use pilot projects to cost-effectively high grade our extensive acreage position before committing development capital in a particular area. In the case of the Shelby pilot, the pressure and production results to date do not provide a sufficient likelihood of commercial success to move into development at this early stage. Production history, as well as our ongoing work to reduce development costs and improve well performance, may make development at the Shelby pilot area viable in the future. The Shelby pilot represents only 400 acres of our 500,000-acre leasehold position.

During the current quarter ended April 30, 2007, we commenced the drilling of 11 new wells, which included two development wells, four pilot wells, one pressure observation well, one water disposal well and three test wells. Eight of these wells are in the Northern Illinois Basin Project, two are in the Southern Basin Project, and one is in the Western Basin Project.

In April 2007, we initiated our third pilot project in Macoupin County. This 12-well pilot program will consist of 10 pilot wells, one pressure observation well, and one water disposal well. Including wells drilled after the end of the current quarter, all 12 wells have been drilled and will be completed and pumping by July 2007.

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.

Our current plan anticipates that for the remaining three months of fiscal year 2007, we will incur approximately $7 million to drill 38 new wells, which includes 26 development wells, eight pilot wells, two pressure observation wells and two test wells. In addition to our drilling program, we expect to continue to pursue the acquisition of additional CBM rights during the fiscal year. Our cash balance at April 30, 2007 of $7.1 million is insufficient to fully fund our forecasted capital expenditures and net cash used by operating activities during our 2007 fiscal year or our operations beyond that date. We expect that the capital expenditure requirements related to our drilling program and our other cash requirements will be funded by our cash balance and cash raised through borrowings, the issuance of debt securities and/or equity securities and/or joint ventures, all of which we are actively pursuing. Although we are currently evaluating the best methods of raising those funds, we can provide no assurance that we will be able to raise the necessary funds.

Management s focus for the remainder of fiscal year 2007 will be to:

- raise the capital needed to fund our fiscal 2008 drilling program;
- obtain test data and initiate pilot projects that demonstrate the commercial potential of CBM at our various acreage blocks and projects in the Basin;
- continue to 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 Basin. These pilot projects may have the potential to grow into development projects that will increase our total 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 technical evaluation of the assets that we control should lead to more cost effective drilling and completion techniques that can be implemented to improve capital efficiency, 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 for 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 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 with 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.

Results of Operations

Three Months Ended April 30, 2007 Compared to Three Months Ended April 30, 2006

The following table presents our unaudited financial data for the third quarter of fiscal year 2007 compared to the third quarter of fiscal year 2006:

	Three Months Ended April 30,			
	2007	**2006**	**Dollar Variance**	**% Change**
Revenues:				
Gas sales	$ 334,706	$ 262,860	$ 71,846	27%
Expenses:				
Lease operating expense	411,938	290,844	121,094	42%
General and administrative expense	1,885,061	2,054,434	(169,373)	(8%)
Depreciation, depletion and amortization	215,280	189,988	25,292	13%
Total operating expenses	2,512,279	2,535,266	(22,987)	(1%)
Operating loss	(2,177,573)	(2,272,406)	94,833	4%
Other income (expenses):				
Interest income	108,660	229,888	(121,228)	(53%)
Interest expense	(1,437)	(4,276)	2,839	66%
Other income (expense)		(2,894,794)	2,894,794	100%
	107,223	(2,669,182)	2,776,405	104%

Net loss	$ (2,070,350)	$ (4,941,588)	$ 2,871,238	58%

Revenue During the third quarter of fiscal year 2007, net gas sales increased $71,846 over the third quarter of fiscal year 2006. Net sales of gas (net of royalties) were 48,558 Mcf for the third quarter of fiscal year 2007, or 35% higher compared to 35,868 Mcf for the third quarter of 2006. Our average realized selling price per Mcf was $6.81 for the third quarter of fiscal year 2007, compared to $7.33 for the third quarter of fiscal year 2006. The increase in net sales would have been greater except for a nitrogen-related pipeline

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curtailment that began in October 2006 and resulted in constrained sales volume until we installed a nitrogen-rejection unit during March 2007.

Lease operating expense During the third quarter of fiscal year 2007, lease operating expense increased $121,094 over the third quarter of fiscal year 2006. Lease operating expense represents production expenses, consisting primarily of repairs and maintenance, fuel and electricity, equipment rental, workovers and labor and overhead expenses directly related to producing wells. The increase is primarily due to an increase in the number of producing wells and the related costs incurred as a result of the increase in gas production at the Southern Illinois Basin Project, new lease operating expenses at our pilot project in the Northern Illinois Basin, and the hiring of additional personnel.

General and administrative expense General and administrative expense consisted of the following for the third quarter of fiscal years 2007 and 2006, respectively:

	Three Months Ended April 30,			
	2007	**2006**	**Dollar Variance**	**% Change**
Salaries and benefits	$ 1,056,604	$ 422,436	$ 634,168	150%
Share-based payments	211,381	647,261	(435,880)	(67%)
Professional and regulatory	466,373	890,591	(424,218)	(48%)
Other	150,703	94,146	56,557	60%
Total general and administrative expense	$ 1,885,061	$ 2,054,434	$ (169,373)	(8%)

During the third quarter of fiscal year 2007, salaries and benefits increased $634,168 over the third quarter of fiscal year 2006. Salaries and benefits associated with base salaries increased approximately $170,000 primarily as a result of hiring additional personnel to support our growth, including our Chief Operating Officer, three engineers and a geologist, and from annual salary increases. In addition, accrued bonuses included in salaries and benefits were $565,000 (annual deferred compensation) during the current quarter compared to $100,000 (signing bonus) during the third quarter of fiscal 2006.

During the third quarter of fiscal year 2007, non-cash expense associated with share-based payments decreased $435,880 over the third quarter of fiscal year 2006. Share-based payments for the third quarter of fiscal year 2007 consist solely of expense recognized on a pro-rata basis for the anticipated vesting of restricted shares outstanding. Share-based payments for the third quarter of fiscal year 2006 represented approximately $625,000 of expense related to fully vested shares granted to a new officer and a new director and approximately $22,000 of expense recognized on a pro-rata basis for the anticipated vesting of restricted shares outstanding. We intend to continue to rely on the granting of equity-based awards, primarily restricted shares, in order to attract and retain qualified individuals and to conserve cash so that it may be utilized in executing our drilling program.

During the third quarter of fiscal year 2007, professional and regulatory expenses decreased $424,218 over the third quarter of fiscal year 2006. The net decrease is primarily due to decreased legal fees as a result of the settlement with Colt LLC during fiscal year 2006.

During the third quarter of fiscal year 2007, other general and administrative expenses increased $56,557 over the third quarter of fiscal year 2006, primarily due to additional rent and office expenses related to the Edwardsville, Illinois office, which opened in May 2006, and higher travel-related expenses associated with increased investor relations activities.

Depreciation, depletion and amortization expense During the third quarter of fiscal year 2007, depreciation, depletion and amortization (DD&A) increased $25,292 over the third quarter of fiscal year 2006. We compute DD&A on capitalized acquisition and development costs (including 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 the third quarter of fiscal year 2006. Additionally, depreciation expense increased due to additions to other support equipment.

Interest income During the third quarter of fiscal year 2007, interest income decreased $121,228 over the third quarter of fiscal year 2006 due to lower average cash balances during the third quarter of fiscal year 2007.

Other income (expense) During the third quarter of fiscal year 2007, other expense decreased $2,894,794 from the third quarter of fiscal year 2006 due solely to the loss that was recognized in the third quarter of fiscal year 2006 related to the settlement with Colt LLC.

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Nine Months Ended April 30, 2007 Compared to Nine Months Ended April 30, 2006

The following table presents our unaudited financial data for the first nine months of fiscal year 2007 compared to the first nine months of fiscal year 2006:

	Nine Months Ended April 30,			
	2007	**2006**	**Dollar Variance**	**% Change**
Revenues:				
Gas sales	$ 875,615	$ 800,365	$ 75,250	9%
Expenses:				
Lease operating expense	1,275,685	752,454	523,231	70%
General and administrative expense	6,089,287	4,491,676	1,597,611	36%
Depreciation, depletion and amortization	591,275	402,680	188,595	47%
Total operating expenses	7,956,247	5,646,810	2,309,437	41%
Operating loss	(7,080,632)	(4,846,445)	(2,234,187)	(46%)
Other income (expenses):				
Interest income	493,982	632,693	(138,711)	(22%)
Interest expense	(7,616)	(18,054)	10,438	58%
Other income (expense)		(2,757,271)	2,757,271	100%
	486,366	(2,142,632)	2,628,998	123%
Net loss	$ (6,594,266)	$ (6,989,077)	$ 394,811	6%

Revenue During the first nine months of fiscal year 2007, net gas sales increased $75,250 over the first nine months of fiscal year 2006. Net sales of gas (net of royalties) were 137,400 Mcf for the first nine months of fiscal year 2007, or 65% higher compared to 83,107 Mcf for the first nine months of 2006. However, our average realized selling price per Mcf decreased to $6.34 for the first nine months of fiscal year 2007 from $9.63 for the first nine months of fiscal year 2006. Net sales were also negatively impacted by a nitrogen-related pipeline curtailment that began in October and necessitated six days of downtime followed by a period of constrained sales volume during the second quarter and a portion of the third quarter of fiscal year 2007. A nitrogen-rejection unit was constructed and began operating during March 2007 and daily production and sales have since reached new highs.

Lease operating expense During the first nine months of fiscal year 2007, lease operating expense increased $523,231 over the first nine months of fiscal year 2006. Lease operating expense represents production expenses, consisting primarily of repairs and maintenance, fuel and electricity, equipment rental, workovers and labor and overhead expenses directly related to producing wells. The increase is primarily due to expenses associated with non-recurring workover projects incurred during the second quarter of fiscal year 2007 at the Southern Illinois Basin Project designed to increase production of existing wells, as well as an increase in the number of producing wells and the related costs incurred due to the increase in gas production at the Southern Illinois Basin Project, new lease operating expenses at our pilot project in the Northern Illinois Basin and the hiring of additional personnel.

General and administrative expense General and administrative expense consisted of the following for the first nine months of fiscal years 2007 and 2006, respectively:

Nine Months Ended April 30,

	2007	2006	Dollar Variance	% Change
Salaries and benefits	$ 2,835,656	$ 1,149,675	$ 1,685,981	147%
Share-based payments	1,088,684	1,044,847	43,837	4%
Professional and regulatory	1,684,909	1,962,733	(277,824)	(14%)
Other	480,038	334,421	145,617	44%
Total general and administrative expense	$ 6,089,287	$ 4,491,676	$ 1,597,611	36%

During the first nine months of fiscal year 2007, salaries and benefits increased $1,685,981 over the first nine months of fiscal year 2006. The net increase was primarily the result of annual bonuses, increased base salaries associated with hiring additional personnel

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to support our growth, including our Chief Operating Officer, three engineers and a geologist, and cash signing bonuses totaling $350,000 paid to such personnel. In addition, expense for the first nine months of fiscal year 2007 includes $250,000 severance paid to our former Chief Financial Officer and General Counsel, who resigned in October 2006.

During the first nine months of fiscal year 2007, non-cash expense associated with share-based payments increased $43,837 over the first nine months of fiscal year 2006. Share-based payments for the first nine months of fiscal year 2007 represent approximately $620,000 of expense recognized for the anticipated vesting of restricted shares outstanding, approximately $267,000 of expense related to the grant of 350,000 unrestricted common shares to newly hired members of our technical team and approximately $202,000 of expense related to the grant of 248,661 unrestricted common shares to certain executive officers, employees and non-employee directors in connection with bonuses and directors fees. Share-based payments for the first nine months of fiscal year 2006 represented approximately $398,000 of expense for options granted to employees and directors to purchase 495,000 common shares valued at approximately $.80 per option using the Black-Scholes valuation method, approximately $625,000 of expense related to fully vested shares granted to a new officer and a new director and approximately $22,000 of expense recognized on a pro-rata basis for the anticipated vesting of restricted shares outstanding. We intend to continue to rely on the granting of equity-based awards, primarily restricted shares, in order to attract and retain qualified individuals and to conserve cash so that it may be utilized in executing our drilling program.

During the first nine months of fiscal year 2007, professional and regulatory expenses decreased $277,824 over the first nine months of fiscal year 2006. The net decrease is primarily due to decreased legal fees related to the Colt LLC litigation as a result of the settlement with Colt LLC during fiscal year 2006 and lower professional and regulatory fees associated with filing initial SEC registration statements and listing on the American Stock Exchange during the first nine months of fiscal year 2006. These decreases were partially offset by higher investor relations fees, higher I.T. consulting fees, and higher employee relocation fees related to the hiring of our new technical team.

During the first nine months of fiscal year 2007, other general and administrative expenses increased $145,617 over the first nine months of fiscal year 2006, primarily due to additional rent and office expenses related to the Edwardsville, Illinois office, which opened in May 2006, and higher travel-related expenses associated with increased investor relations activities.

Depreciation, depletion and amortization expense During the first nine months of fiscal year 2007, DD&A increased $188,595 over the first nine months of fiscal year 2006. We compute DD&A on capitalized acquisition and development costs (including 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 the first nine months of fiscal year 2006. Additionally, depreciation expense increased due to additions to other support equipment.

Interest income During the first nine months of fiscal year 2007, interest income decreased $138,711 over the first nine months of fiscal year 2006 due to lower average cash balances during the first nine months of fiscal year 2007.

Other income (expense) During the first nine months of fiscal year 2007, other expense decreased $2,757,271 from the third quarter of fiscal year 2006 due solely to the loss that was recognized in the third quarter of fiscal year 2006 related to the settlement with Colt LLC.

Critical Accounting Policies and Estimates

Our unaudited 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 critical to our results of operations or financial position are discussed in Item 7 of our Annual Report on Form 10-K for the fiscal year ended July 31, 2006. There were no material changes in these policies during the current quarter.

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Financial Condition

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 April 30, 2007, we had only $83,460 in long-term notes payable. From July 31, 2003 until April 30, 2007, we raised $43,198,616 from the sale of our common shares. Additionally, during that same period, we collected $6,728,810 and $2,042,280 as a result of the exercise of warrants and stock options, respectively. Our primary use of these funds has been the acquisition, exploration, testing and development of our CBM properties and rights and payment of general and administrative expenses required to support our operations.

We did not begin to generate revenues from CBM sales until January 2005. Revenues from CBM sales were $875,615 and $800,365 for the first nine months of fiscal years 2007 and 2006, respectively, and $334,706 and $262,860 for the quarters ended April 30, 2007 and 2006, respectively. Subject to the various risks described in this report, we expect revenue from the sale of our CBM to increase due to (i) increased production from existing wells as they continue to dewater and (ii) additional production generated as a result of drilling and production from additional wells. However, in view of the fact that we have very little historical experience of dewatering and gas production in the Basin, we can provide no assurance that we will achieve a trend of increased production and revenue in the future.

In addition, CBM wells typically must go through a lengthy dewatering phase before making a significant 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 significant contribution to our cash from operations. Additionally, net cash generated (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 equipment;
- lease terms;
- availability of sufficient capital resources; and
- the accuracy of production estimates for current and future wells.

We had a cash balance of $7,070,656 as of April 30, 2007, compared to $19,279,015 at July 31, 2006. The net decrease in our cash balance is primarily due to the net cash used in operating activities of $5,280,465, consisting primarily of payments for salaries and benefits, professional fees and lease operating expenses adjusted for changes in working capital, and net cash used in investing activities of $6,795,339, consisting of capital expenditures related primarily to development costs. We also made repayments of long-term notes in the amount of $132,555 during the current fiscal year.

We have no significant contractual commitments for capital expenditures. However, our plan anticipates that for the remaining three months of fiscal year 2007, we will incur approximately $7 million to drill 38 new wells, which includes 26 development wells, eight pilot wells, two pressure observation wells, and two test wells. In addition to our drilling program, we expect to continue to pursue the acquisition of additional CBM rights during the fiscal year. We expect that the capital expenditure requirements related to our drilling program and our other cash requirements will be funded by our cash balance and cash raised through borrowings, the issuance of debt securities and/or equity securities and/or joint ventures, all of which we are actively pursuing. 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.

Cautionary Statement Concerning Forward-Looking Statements

Some of the statements contained in this report that are not historical facts, including statements containing the words believes, anticipates, expects, intends, plans, should, may, might, continue and estimate and simil forward-looking statements under the federal securities laws. 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 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, but are not limited to: (a) our inability to generate sufficient income or obtain sufficient financing to fund our operations or drilling plan through July 31, 2007 or thereafter; (b) our inability to retain our acreage rights at our projects, at the expiration of our lease agreements, due to insufficient CBM production or for other reasons; (c) our failure to accurately forecast CBM production; (d) displacement of our CBM operations by coal mining operations, which have superior rights in most of our acreage; (e) our failure to accurately forecast the number of wells that we can drill; (f) a decline in the prices that we receive for our CBM production; (g) our failure to accurately forecast operating and capital expenditures and capital needs due to rising costs or different drilling or production conditions in the field; (h) our inability to attract or retain qualified personnel with the requisite CBM or other experience; and (i) unexpected economic and market conditions, in the general economy or the market for natural gas. We caution readers not to place undue reliance on these forward-looking statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk

Our major risk exposure is the commodity pricing applicable to our CBM production. Realized commodity prices received for our production are primarily driven by the spot prices attributable to natural gas. The effects of price volatility are expected to continue.

Interest Rate Risk

All of our debt has fixed interest rates. Consequently, we are not exposed to cash flow or fair value risk from market interest rate changes on this debt.

Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable and long-term notes payable. The carrying amount of cash equivalents, accounts receivable and accounts payable approximate fair market value due to the highly liquid nature of these short-term instruments.

Inflation and Changes in Prices

The general level of inflation affects our costs. Salaries and other general and administrative expenses are impacted by inflationary trends and the supply and demand of qualified professionals and professional services. Inflation and price fluctuations affect the costs associated with exploring for and producing CBM, which has a material impact on our financial performance.

Item 4. Controls and Procedures

As of the end of the period covered by this report, we conducted an evaluation, under the supervision and with the participation of our Chief Executive Officer and Controller (who is currently responsible for performing certain functions of our principal financial officer), of the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)). Based on this evaluation, our Chief Executive Officer and Controller have concluded that our disclosure controls and procedures are effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms.

There have been no changes in our internal control over financial reporting identified in connection with the evaluation required by Rule 13a-15(d) of the Exchange Act that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Drummond Coal Co. Litigation

BPI Energy, Inc. (BPI) is currently subject to litigation with respect to approximately 115,000 acres of its CBM rights that are located at the Northern Illinois Basin Project. To date, BPI has drilled one well on this acreage, a test well that was drilled in September 2006. This well is not currently at the production stage.

In 2004, BPI and affiliates of the Drummond Coal Co. (Drummond), including IEC (Montgomery), LLC (IEC), entered into a letter of intent to obtain coal and CBM gas rights for one another in the Illinois Basin and to work together in a relationship in which BPI would extract CBM from coal beds prior to the Drummond affiliates mining of coal from those beds. Pursuant to and in reliance upon this letter of intent and its relationship with Drummond, BPI arranged for the transfer of 163,109 acres of coal rights to the Drummond affiliates for a total purchase price of $5,845,500, which BPI believes reflects a significant discount to current market prices. In light of its obligations to Drummond, BPI charged no profit on its transfer of the coal rights to the Drummond affiliates. Rather, in consideration for obtaining those coal rights, the Drummond affiliates were to lease approximately 115,000 acres of CBM rights to BPI for a primary lease term of 20 years and with favorable royalty rates. Although the Drummond affiliates entered into two CBM leases with BPI on April 26, 2006, they have since sought in various ways to void or terminate the leases.

Ignoring mandatory arbitration provisions in the CBM leases, Drummond affiliates IEC and Christian Coal Holdings, LLC (Christian) filed suit against BPI on February 9, 2007 in the United States District Court for the Northern District of Alabama, claiming that BPI has breached the CBM leases in various ways. Specifically, although the CBM leases include no specific drilling commitments, IEC and Christian allege that BPI has breached the CBM leases by failing to use best efforts to commercially produce all economically recoverable gas. IEC and Christian also allege that BPI has breached the CBM leases by failing to provide maps of existing and proposed gas wells and facilities every six months and failing to maintain required insurance coverage. BPI refutes each of these allegations and intends to vigorously defend the Drummond affiliates claims of breach. In addition, BPI moved to dismiss the lawsuit for lack of standing, lack of personal jurisdiction and improper venue, or in the alternative to transfer the case to either Ohio or Illinois. BPI also moved the court to stay or dismiss the Alabama lawsuit and to compel arbitration under the CBM leases. On May 14, 2007, the Court granted BPI s motion to dismiss on the ground of improper venue. BPI anticipates that IEC and Christian may appeal the decision, move the Court to reconsider it, or reinstitute litigation in a different venue.

On March 13, 2007, BPI filed suit against IEC, Christian and additional Drummond affiliates Shelby Coal Holdings, LLC, Clinton Coal Holdings, LLC and Marion Coal Holdings, LLC in the United States District Court for the Southern District of Illinois. At the court s direction, BPI filed an amended complaint on April 13, 2007. In its lawsuit, BPI seeks to rescind its transfers of coal rights to the Drummond affiliates for failure of consideration due to the Drummond affiliates efforts to avoid the CBM leases, and has also asserted claims for money damages for breach of contract, breach of fiduciary duty, unjust enrichment and promissory estoppel. The defendants filed a motion to dismiss the amended complaint, to which BPI currently is preparing a response.

We believe that Drummond and its affiliates, after having received favorable coal rights in exchange for favorable CBM rights, now wish to obtain a significant windfall by seeking to renege on the CBM rights that they were obligated to grant to BPI.

If the Drummond affiliates reinstitute their claims against BPI, we believe that we will be successful in defending against their claims of breach. However, there can be no assurance that we will be successful in maintaining these acreage rights. The loss of these acreage rights would not have a material impact on our financial position, results of operations or cash flows.

ICG Litigation

In November 2004, BPI entered into a farmout agreement under which it acquired the right to develop certain CBM in Macoupin and Perry counties in Illinois. The farmout agreement covers 41,253 acres of CBM rights in Macoupin County and 22,997 acres of CBM rights in Perry County. The farmor was Addington Exploration, LLC, which leased the CBM rights from Meadowlark Farms, Inc. and Ayrshire Land Company. Meadowlark and Ayrshire went into bankruptcy, and ICG Natural Resources, LLC purchased their assets, including the CBM rights underlying the

Addington leases. On April 9, 2007, ICG filed suit against BPI in Perry County, Illinois, in an effort to avoid the Addington leases, claiming that there was a lack of consideration at the time they

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were originally entered into. BPI has filed a motion to dismiss the lawsuit under the doctrine of estoppel by deed, arguing that ICG cannot challenge the leases because it acquired the CBM rights subject to those leases, as set forth in the deed from Addington and Meadowlark to ICG, the purchase agreement between those parties, and numerous bankruptcy court filings and orders associated with the approval of the sale. Addington was subsequently acquired by Nytis Exploration Company, LLC, which has intervened in the action and joined in BPI s motion. To date, BPI has drilled 10 pilot wells, one pressure observation well and one water disposal well on the acreage covered by the farmout agreement.

We believe that we will be successful in either having the case dismissed or in defending against ICG s claims. However, there can be no assurance that we will be successful in retaining the acreage under this farmout agreement.

Item 1A. Risk Factors

There are no material changes to the risk factors previously reported in our Annual Report on Form 10-K for the fiscal year ended July 31, 2006. For more information regarding such risk factors, please refer to Item 1A of our Annual Report on Form 10-K for the fiscal year ended July 31, 2006.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information

On June 7, 2007, the Compensation Committee (the Committee) of our Board of Directors approved and adopted the BPI Energy Holdings, Inc. Senior Executive Severance Plan and the BPI Energy Holdings, Inc. Key Employee Severance Plan, which provide severance benefits to our employees designated by the Committee.

Senior Executive Severance Plan

The Senior Executive Severance Plan currently applies to James G. Azlein, our Chief Executive Officer, and James E. Craddock, our Chief Operating Officer, and may later include other executive officers designated by the Committee. The Senior Executive Severance Plan provides that, in the event of an executive officer s death or disability, we will pay (i) any accrued base salary through the termination date, (ii) any unpaid cash bonus from a completed year, and (iii) a pro-rated current year bonus.

If we terminate an executive officer's employment without cause before a change of control (as that term is defined in the Senior Executive Severance Plan) or the executive officer resigns for good reason (as that term is defined in the Senior Executive Severance Plan) before a change of control, we will provide (i) any accrued base salary through the termination date, (ii) any unpaid cash bonus from a completed year, (iii) a pro-rated current year bonus, (iv) a lump sum cash payment equal to two times the sum of the executive officer s base salary and target annual bonus, (v) reimbursement for the cost of continued group medical and dental insurance coverage for the executive officer and his immediate family for two years or until the executive officer becomes eligible for similar coverage through subsequent employment, and (vi) reimbursement of up to $20,000 for outplacement services utilized within a year of termination. If we terminate an executive officer s employment without cause within two years after a change of control, or the executive officer resigns (a) for good reason at any time within two years after a change of control or (b) with or without good reason during the 60-day period beginning exactly six months after a change of control, we will provide the same benefits as upon termination before a change of control except that the lump sum cash payment will equal three times the sum of the executive officer s base salary and maximum annual bonus. In addition, we will provide reimbursement for the cost of continued medical and dental insurance coverage for three, rather than two, years following the termination date or until the executive officer becomes eligible for similar coverage through subsequent employment.

Under the Senior Executive Severance Plan, upon any termination following a change of control, (i) all restrictions on restricted shares held by the executive officer will lapse, (ii) all options that vest solely on the basis of the expiration of time will become fully vested, and (iii) all options that vest in whole or in part on the basis of company or individual performance will vest proportionately as of the termination date. The period for exercising stock options that vest on or before the termination date will be extended until the earlier of (i) the third anniversary of the termination date or (ii) the original expiration date of the option.

The Senior Executive Severance Plan provides for a two-year confidentiality period and contains a one-year non-solicitation provision. Additionally, if we terminate an executive officer before a change of control with or without cause, or an executive officer resigns for good reason before a change of control, the executive officer will be bound by a one-year non-competition provision for the area encompassing a ten-mile radius of our currently owned and active prospect acreage.

The foregoing summary description of the Senior Executive Severance Plan is qualified in its entirety by the full text of the Senior Executive Severance Plan, which is filed with this Quarterly Report on Form 10-Q as Exhibit 10.1.

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Key Employee Severance Plan

The Key Employee Severance Plan applies to any regular full-time employee who is designated by the Committee to participate in the Key Employee Severance Plan and who is not covered under the Senior Executive Severance Plan. Randy L. Elkins, our Acting Chief Financial Officer, is currently our only executive officer covered under the Key Employee Severance Plan.

The Key Employee Severance Plan provides that, in the event of an employee s death or disability, we will pay (i) any accrued base salary through the termination date, (ii) any unpaid cash bonus from a completed year, and (iii) a pro-rated current year bonus.

If, at any time within two years after a change of control, we terminate an employee without cause, or the employee resigns for good reason we will provide (i) any accrued base salary through the termination date, (ii) any unpaid cash bonus from a completed year, (iii) a pro-rated current year bonus, (iv) a lump sum cash payment equal to one and one-half times the sum of the employee s base salary and maximum annual bonus, (v) reimbursement for the cost of continued group medical and dental insurance coverage for the employee and his immediate family for two years or until the employee becomes eligible for similar coverage through subsequent employment, and (vi) reimbursement of up to $5,000 for outplacement services utilized within a year of termination.

The Key Employee Severance Plan contains provisions on the vesting of restricted shares and options, confidentiality, non-solicitation and non-competition that are identical to those that are included in the Senior Executive Severance Plan.

The foregoing summary description of the Key Employee Severance Plan is qualified in its entirety by the full text of the Key Employee Severance Plan, which is filed with this Quarterly Report on Form 10-Q as Exhibit 10.2.

Item 6. Exhibits

10.1	BPI Energy Holdings, Inc. Senior Executive Severance Plan dated June 7, 2007.
10.2	BPI Energy Holdings, Inc. Key Employee Severance Plan dated June 7, 2007.
31.1	Section 302 Certification of the Chief Executive Officer (Principal Executive Officer).
31.2	Section 302 Certification of the Acting Chief Financial Officer (Principal Financial Officer).
32.1	Section 906 Certification of the Principal Executive Officer and Principal Financial Officer.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BPI ENERGY HOLDINGS, INC.

DATE: June 13, 2007

/s/ James G. Azlein
James G. Azlein,
President and Chief Executive Officer

/s/ Randy L. Elkins
Randy L. Elkins,
Controller and Acting Chief Financial Officer

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