FOOTHILLS RESOURCES INC
Form 10-K
May 11, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2008

or

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

For the transition period from __________ to __________

Commission file number 001-31547

FOOTHILLS RESOURCES, INC.

(Name of small business issuer in its charter)

Nevada	**98-0339560**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
4540 California Avenue, Suite 550 Bakersfield, California	**93309**
(Address of principal executive offices)	(Zip Code)

(661) 716-1320

(Issuer s telephone number, including area code)

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

None	**None**
(Title of Class)	(Name of Each Exchange on Which Registered)

Securities registered under Section 12(g) of the Act:

Common Stock, $0.001 par value	**None**
(Title of Class)	(Name of Each Exchange on Which Registered)

Indicate by check mark whether the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments to this Form 10-K. o

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

Large accelerated filer o	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company 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

The aggregate market value of the voting common equity held by non-affiliates as of March 31, 2009, was approximately $319,302, computed by reference to the price of $0.007 per share, the price at which the common equity was last sold on such date as reported on the Over-the-Counter Bulletin Board Exchange. For purposes of this computation, it is assumed that the shares beneficially held by directors and officers of the registrant would be deemed to be stock held by affiliates.

On March 31, 2009, 60,557,637 shares of common stock were outstanding.

FOOTHILLS RESOURCES, INC. AND SUBSIDIARIES
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References in this Annual Report on Form 10-K (this Form 10-K or this Report) to Foothills, the Company, we, our, and us refers to Foothills Resources, Inc., a Nevada corporation, and our wholly owned subsidiaries.

Forward-Looking Statements

This Form 10-K contains statements that constitute forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934 and Section 27A of the Securities Act of 1933. This Form 10-K includes statements regarding our plans, goals, strategies, intent, beliefs or current expectations. These statements are expressed in good faith and based upon a reasonable basis when made, but there can be no assurance that these expectations will be achieved or accomplished. These forward looking statements can be identified by the use of terms and phrases such as believe, plan, intend, anticipate, target, estimate, expect, and the like, and/or future-tense or conditional constructions may, could, should, and variations of these words. Items contemplating or making assumptions about, actual or potential future oil and gas production, oil and gas reserve estimates, drilling activities and operating results also constitute such forward-looking statements. These forward-looking statements are not guarantees of future performance and involve risks and uncertainties, and actual results may differ materially from those projected in this Form 10-K, for the reasons, among others, discussed in the Sections Management s Discussion and Analysis of Financial Condition and Results of Operations, and Risk Factors. We undertake no obligation to publicly revise these forward-looking statements to reflect events or circumstances that arise after the date hereof.

PART I.

Item 1. Description of Business.

Company Overview

Foothills, a Nevada corporation originally formed in November 2000, is an oil and gas exploration company engaged in the acquisition, exploration and development of oil and natural gas properties. The Company s operations are primarily those of Foothills California, Inc., Foothills Texas, Inc. and Foothills Oklahoma, Inc., our wholly-owned subsidiaries. Foothills California, Inc., a Delaware corporation, was formed in December 2005 as Brasada Resources LLC, a Delaware limited liability company, and converted to Brasada California, Inc., a Delaware corporation, in February 2006. In April 2006, Brasada California, Inc. merged with our wholly-owned acquisition subsidiary, leaving Brasada California, Inc. the surviving corporation and our wholly-owned subsidiary. Brasada California, Inc. later changed its name to Foothills California, Inc. following the merger. Foothills Oklahoma, Inc. was formed in May 2006 to conduct our operations in Oklahoma. Foothills Texas, Inc. was formed in August 2006 for the purpose of acquiring certain assets from TARH E&P Holdings, L.P. and operating those properties following the consummation of this acquisition in September 2006. We currently conduct our operations primarily through these subsidiaries.

Prior to our acquisition of the properties of TARH E&P Holdings, L.P. in Texas, our primary focus was on oil and natural gas properties located in the Eel River Basin, California, and the Anadarko Basin, Oklahoma. The TARH E&P Holdings acquisition expanded our operations into Texas, though we continue to operate our properties in California and pursue exploration project generation activity in Oklahoma.

Our business strategy is to identify and exploit low-to-moderate risk hydrocarbon resources in existing producing areas that can be quickly developed and put on production at low cost, including the acquisition of producing properties with exploitation and exploration potential in these areas. We also intend to develop exploratory projects in focus areas and to participate with other companies in those areas to explore for oil and natural gas using state-of-the-art 3D seismic technology.

Recent Developments Chapter 11 Proceedings

As has been previously announced, we, along with each of our subsidiaries, filed voluntary petitions for reorganization relief under Chapter 11 (the Chapter 11 Cases) of the United States Bankruptcy Code (the Bankruptcy Code) in the United States Bankruptcy Court for the District of Delaware (the Bankruptcy Court) on February 11, 2009. The Chapter 11 Cases are being jointly administered under the caption *Foothills Texas, Inc., et al., Debtors, Chapter 11 Case No. 09-10452 (CSS)*. We continue to operate our business as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with applicable provisions of the Bankruptcy Code and the orders of the Bankruptcy Court.

As debtors-in-possession, we are authorized to continue to operate as ongoing businesses, and may pay all debts and honor all obligations arising in the ordinary course of our businesses after the filing of the Chapter 11 Cases. However, we may not pay creditors on account of obligations arising before the filing of the Chapter 11 Cases or engage in transactions outside the ordinary course of business without approval of the Bankruptcy Court, after notice and an opportunity for a hearing.

Under the Bankruptcy Code, actions to collect pre-petition indebtedness are stayed. Other pre-petition contractual obligations against us generally may not be enforced absent an order of the Bankruptcy Court providing otherwise. Substantially all pre-petition liabilities are subject to settlement under a plan of reorganization to be voted upon by creditors and other stakeholders, and approved by the Bankruptcy Court.

Under the priority scheme established by the Bankruptcy Code, certain post-petition and secured or priority pre-petition liabilities need to be satisfied before general unsecured creditors and holders of our equity are entitled to receive any distribution. No assurance can be given as to what values, if any, will be ascribed in the bankruptcy proceedings to the claims and interests of each of these constituencies. Additionally, no assurance can be given as to whether, when or in what form unsecured creditors and holders of our equity may receive a distribution on such claims or interests. Based on the terms of the proposed plan of reorganization currently under discussion, we expect our outstanding common stock will be extinguished and current shareholders will not receive any meaningful recovery, and may not receive any distribution or other consideration for their shares.

Under the Bankruptcy Code, we may assume, assume and assign, or reject certain executory contracts and unexpired leases, including, without limitation, leases of real property and equipment, subject to the approval of the Bankruptcy Court and certain other conditions. Any description of an executory contract or unexpired lease in this Form 10-K must be read in conjunction with, and is qualified by, any overriding rejection rights we have under the Bankruptcy Code.

For the duration of the Chapter 11 Cases, our business is subject to the risks and uncertainties of bankruptcy. For example, the Chapter 11 Cases could adversely affect our relationships with customers, suppliers and employees which, in turn, could adversely affect the going concern value of our business and of our assets. At this time, it is not possible to predict with certainty the effect of the Chapter 11 Cases on our business or various creditors, or when or if we will emerge from bankruptcy. Our future results depend on the court confirming, and our successful implementation of, all on a timely basis, a plan of reorganization.

The filing of the Chapter 11 Cases triggered an automatic event of default under our Credit Agreement, dated as of December 13, 2007, by and among us, each of our subsidiaries as borrowers, certain lenders and Wells Fargo Foothill LLC, as administrative agent, as amended (the Pre-Petition Credit Facility). As a result of the event of default, all obligations under the Pre-Petition Credit Facility became immediately due and payable, subject to an automatic stay of any action to collect, assert or recover a claim against us and the application of applicable bankruptcy law.

In connection with the Chapter 11 Cases, on February 23, 2009, we entered into the DIP Credit Agreement with the lenders who are parties thereto (the Lenders), Regiment Capital Special Situations Fund III, L.P., as agent, and our subsidiaries, as guarantors (the DIP Credit Agreement). The Bankruptcy Court approved the DIP Credit Agreement on an interim basis on February 12, 2009 and entered a final approval order on March 3, 2009.

The DIP Credit Agreement provides for revolving loans up to an aggregate of $2.5 million (the Loans). The proceeds of the Loans will be used for working capital purposes, including the payment of fees, costs, and expenses incurred in connection with the DIP Credit Agreement and for expenditures consistent with a budget agreed upon by the Company and the Lenders pursuant to the DIP Credit Agreement. Interest will accrue under the DIP Credit Agreement at 12% per annum, provided however, following an event of default under the DIP Credit Agreement, interest will accrue at an annual rate equal to 2% above the annual rate otherwise applicable. The obligations under the DIP Credit Agreement are secured, subject to certain limited exceptions, by substantially all of the assets of the Company, including a super-priority administrative expense claim pursuant to Bankruptcy Code Section 364(c)(1).

The Loans will mature on the earliest of:

- May 19, 2009,
- the date of substantial consummation of a plan of reorganization in the Chapter 11 Cases that has been confirmed by an order of the Bankruptcy Court,
- the date of a sale of substantially all of the assets of the Company, and
- such earlier date on which all Loans and other obligations for the payment of money shall become due and payable in accordance with the terms of the DIP Credit Agreement.

We have obtained court authorization to use cash, negotiable instruments, documents of title, securities, deposit accounts, and other cash equivalents (Cash Collateral) which are subject to security interest pursuant to the Pre-Petition Credit Facility and the DIP Credit Agreement.

We have requested Bankruptcy Court approval to extend the maturity date of the Loans and the authorization to use the Cash Collateral (the Cash Collateral Order) through and including August 19, 2009. A hearing will be held on this request on May 12, 2009.

Markets and Customers

The market for oil and natural gas that we produce depends on factors beyond our control, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of natural gas pipelines and other transportation facilities, demand for oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulation. The oil and gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Our oil production is expected to be sold at prices tied to the oil futures markets. Our natural gas production is expected to be sold under short-term contracts and priced based on first of the month index prices or on daily spot market prices.

Regulations

Our business is affected by numerous laws and regulations, including environmental, conservation, tax and other laws and regulations relating to the energy industry. Most of our drilling operations require permits or authorizations from federal, state or local agencies. Changes in any of these laws and regulations or the denial or vacating of permits could have a material adverse effect on our business. In view of the many uncertainties with respect to current and future laws and regulations, including their applicability to us, we cannot predict the overall effect of such laws and regulations on our future operations.

We believe that our operations comply in all material respects with applicable laws and regulations. There are no pending or threatened enforcement actions related to any such laws or regulations. We believe that the existence and enforcement of such laws and regulations will have no more restrictive an effect on our operations than on other similar companies in the energy industry.

Proposals and proceedings that might affect the oil and gas industry are pending before Congress, the Federal Energy Regulatory Commission (FERC), state legislatures and commissions and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the oil and gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by various agencies will continue indefinitely. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material adverse effect upon our capital expenditures, earnings or competitive position.

State Regulation

Our operations are also subject to regulation at the state and in some cases, county, municipal and local governmental levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandonment of wells and the disposal of fluids used and produced in connection with operations. Our operations are also subject to various conservation laws and regulations pertaining to the size of drilling and spacing units or proration units and the unitization or pooling of oil and gas properties.

In addition, state conservation laws, which frequently establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the rates of production. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, but, does not generally entail rate regulation. These regulatory burdens may affect profitability, but we are unable to predict the future cost or impact of complying with such regulations.

Environmental Matters

We are subject to extensive federal, state and local environmental laws and regulations relating to water, air, hazardous substances and wastes, and threatened or endangered species that restrict or limit our business activities for purposes of protecting human health and the environment. Compliance with the multitude of regulations issued by federal, state, and local administrative agencies can be burdensome and costly. State environmental regulatory programs are generally very similar to the corresponding federal environmental regulatory programs, and federal environmental regulatory programs are often delegated to the states.

Our oil and gas exploration and production operations are subject to state and/or federal solid waste regulations that govern the storage, treatment and disposal of solid and hazardous wastes. However, much of the solid waste that will be generated by our oil and gas exploration and production activities is exempt from regulation under federal, and many state, regulatory programs. To the extent our operations generate solid waste, such waste is generally subject to state and county regulations. We will comply with solid waste regulations in the normal course of business.

In addition to solid and hazardous waste, our production operations may generate produced water as a waste material. This water can sometimes be disposed of by discharging it to surface waters under discharge permits issued pursuant to the Clean Water Act, or an equivalent state program. Another common method of produced water disposal is subsurface injection in disposal wells. Such disposal wells require permitting under the Safe Drinking Water Act, or an equivalent state regulatory program. The drilling, completion, and operation of produced water disposal wells are integral to oil and gas operations.

Air emissions and exhaust from gas-fired generators and from other equipment, such as gas compressors, are potentially subject to regulations under the Clean Air Act, or equivalent state regulatory programs. To the extent that our air emissions are regulated, they are generally regulated by permits issued by state regulatory agencies. We will obtain air permits, where needed, in the normal course of business.

In the event that spills or releases of crude oil or produced water occur, we would be subject to spill notification and response regulations under the Clean Water Act, or equivalent state regulatory programs.

Depending on the nature and location of our operations, we may also be required to prepare spill prevention, control and countermeasure response plans under the Clean Water Act, or equivalent state regulatory programs. Response costs could be high and may have a material adverse effect on our operations. We may not be fully insured for these costs.

Failure to comply with environmental regulations may result in the imposition of substantial administrative, civil, or criminal penalties, or restrict or prohibit our desired business activities. Environmental laws and regulations impose liability, sometimes strict liability, for environmental cleanup costs and other damages. Other environmental laws and regulations may delay or prohibit exploration and production activities in environmentally sensitive areas or impose additional costs on these activities.

Costs associated with responding to a major spill of crude oil or produced water, or costs associated with remediation of environmental contamination, are the most likely occurrences that could result in a material adverse effect on our business, financial condition and results of operations. In addition, changes in applicable federal, state and local environmental laws and regulations potentially could have a material adverse effect on our business, financial condition and results of operations.

Competition

The oil and gas industry is highly competitive. Competitors include major oil companies, other independent energy companies and individual producers and operators, many of which have financial resources, personnel and facilities substantially greater than we have. We face intense competition for the acquisition of oil and gas leases and properties. For a more thorough discussion of how competition could impact our ability to successfully complete our business strategy, see Item 1A. Risk Factors Competition in obtaining rights to explore and develop oil and gas reserves and to market our production may impair our business.

Employees

As of March 31, 2009, the Company had 10 employees. None of our employees are represented by a labor union, and we consider our employee relations to be good.

Item 1A. Risk Factors.

Several of the matters discussed in this Report contain forward-looking statements that involve risks and uncertainties. Factors associated with the forward-looking statements that could cause actual results to differ from those projected or forecasted in this Report are included in the statements below. In addition to other information contained in this Report, you should carefully consider the following cautionary statements and risk factors. The risks and uncertainties described below are not the only risks and uncertainties we face. If any of the following risks actually occur, our business, financial condition, and results of operations could suffer. In that event, the trading price of our common stock could decline, and you may lose all or part of your investment in our common stock. The risks discussed below also include forward-looking statements and our actual results may differ substantially from those discussed in these forward-looking statements.

RISKS RELATED TO OUR CHAPTER 11 BANKRUPTCY PROCEEDINGS

We filed for reorganization under Chapter 11 of the Bankruptcy Code on February 11, 2009, and we do not presently believe that there will be any meaningful recovery, or any recovery at all, for holders of our common stock.

Based on the terms of the proposed plan of reorganization currently under discussion, we expect our outstanding common stock will be extinguished and current shareholders will not receive any meaningful recovery, and may not receive any distribution or other consideration in exchange for their shares. Under the priority scheme established by the Bankruptcy Code, unless creditors agree otherwise in accordance with the Bankruptcy Code, all pre-petition liabilities and post-petition liabilities must be satisfied in full before shareholders are entitled to receive any distribution or retain any property under a plan of reorganization. The ultimate recovery to our shareholders, if any, will not be determined until confirmation of a plan of reorganization. No assurance can be given as to what values, if any, will be ascribed in the Chapter 11 Cases to our shareholders or what types or amounts of distributions, if any, they would receive. If certain requirements of the Bankruptcy Code are met, a plan of reorganization can be confirmed notwithstanding its rejection by equity holders and notwithstanding the fact that equity holders do not receive or retain any property on account of their equity interests under the plan of reorganization.

We intend to deregister our common stock under the Securities Exchange Act of 1934, which could negatively affect the liquidity and trading prices of our common stock.

On April 30, 2009, the Board voted to voluntarily deregister our common stock under the Securities Exchange Act of 1934 (the Exchange Act) and become a non-reporting company. On or about May 11, 2009, we intend to file with the SEC a Form 15, Notice of Termination of Registration and Suspension of Duty to File, to terminate our reporting obligations under the Exchange Act. Once we file the Form 15, our obligation to file reports and other information under the Exchange Act, such as Forms 10-K, 10-Q and 8-K will be suspended. The deregistration of our common stock under the Exchange Act will become effective 90 days after the date on which the Form 15 is filed. We are eligible to deregister under the Exchange Act because our common stock is held of record by fewer than 300 persons. Deregistering our common stock could negatively affect the liquidity, trading volume and trading prices of our common stock.

Our operations are subject to the risks and uncertainties associated with the Chapter 11 Cases.

For the duration of the Chapter 11 Cases, our operations will be subject to the risks and uncertainties associated with bankruptcy. These risks include, among other things:

- our ability to continue as a going concern;
- our ability to operate within the restrictions of the DIP Credit Agreement;
- the actions and decisions of our creditors and other third parties with interests in our Chapter 11 Cases, which may be inconsistent with our plans;
- our ability to obtain Bankruptcy Court approval with respect to motions in the Chapter 11 Cases that we may seek from time to time and potentially adverse decisions by the Bankruptcy Court with respect to such motions;
- our ability to obtain and maintain normal terms with vendors and service providers;
- our ability to obtain additional financing to fund our operations and capital expenditures;
- our ability to retain and motivate key employees through the process of reorganization; and
- the substantial costs for professional fees and other expenses.

Because of the risks and uncertainties associated with the Chapter 11 Cases, we cannot predict or quantify the ultimate effect that events occurring during the reorganization process will have on our business, financial condition, or results of operation, and there is no certainty about our ability to continue as a going concern.

Our liquidity position imposes significant risks to our operations.

Because of the public disclosure of our liquidity issues, and despite the liquidity provided by our DIP Credit Agreement, our ability to maintain normal credit terms with our vendors and service providers may become impaired. We may be required to pay cash in advance to certain vendors and may experience restrictions on the availability of trade credit, which would further reduce our liquidity. If liquidity problems persist, our vendors and service providers could refuse to provide key products and services in the future.

The DIP Credit Agreement provides for an aggregate commitment of up to $2.5 million in revolving loan borrowings. We cannot assure you that the amounts of cash from operations together with amounts available under our DIP Credit Agreement will be sufficient to fund operations. In the event that cash flows and available borrowings under the DIP Credit Agreement are not sufficient to meet our liquidity requirements, we may be required to seek additional financing. We cannot assure you that additional financing will be available or, if available, offered on acceptable terms. Failure to secure any necessary additional financing would have a material adverse impact on our operations. For additional information on our liquidity, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

We may not continue to operate as a going concern.

Our financial statements and related notes accompanying this Form 10-K have been prepared assuming that we will continue as a going concern. The financial statements do not include any adjustments relating to the recoverability and classification of recorded assets, or the amounts and classification of liabilities that might be necessary in the event the we cannot continue in existence. In the event our restructuring activities are not successful and we are required to liquidate, additional significant adjustments will be necessary in the carrying value of assets and liabilities, the revenues and expenses reported and the balance sheet classifications used.

The Chapter 11 Cases raise substantial doubt about our ability to remain a going concern. Our continuation as a going concern is contingent upon, among other things, our ability to:

- comply with the terms of the DIP Credit Agreement,
- reduce administrative, operating and interest costs and liabilities through the bankruptcy process,
- generate sufficient cash flow from operations,
- obtain confirmation of a plan of reorganization under the Bankruptcy Code, and
- obtain financing in order to exit from bankruptcy.

Our credit facility will expire on May 19, 2009, unless a plan of reorganization is approved by the Bankruptcy Court by that date or we are able to obtain an extension.

Our credit facility is currently in the form of a DIP Credit Agreement that we entered into in connection with our Chapter 11 filing. The DIP Credit Agreement is currently scheduled to terminate on the earlier of May 19, 2009, and the effective date of the Company s plan of reorganization. We have requested Bankruptcy Court approval to extend the maturity date of the Loans through and including August 19, 2009. A hearing will be held on this request on May 12, 2009. Any plan of reorganization will require us to obtain financing adequate to meet our working capital needs. We cannot assure you that our plan of reorganization will be effective on or before May 19, 2009, that the Bankruptcy Court will grant our request to extend the maturity date of the DIP Credit Agreement, or that we will be able to obtain necessary exit financing. If the Company is unable to obtain exit financing, we may not continue as a going concern. We cannot assure you that the Company would be able to locate alternative sources of financing.

We may not be able to obtain confirmation of our plan of reorganization.

In order to successfully emerge from bankruptcy protection, we must develop, and obtain requisite court and creditor approval of, a viable plan of reorganization. This process requires us to meet certain statutory requirements with respect to adequacy of disclosure with respect to a plan, soliciting and obtaining creditor acceptance of a plan, and fulfilling other statutory conditions for confirmation. We may not receive the requisite acceptances to confirm our plan of reorganization. Even if the requisite acceptances of a plan are received, the Bankruptcy Court may not confirm it.

If a plan is not confirmed by the Bankruptcy Court it is likely that we would have to liquidate our assets, either through a forced sale pursuant to Section 363 of the Bankruptcy Code or through a Chapter 7 liquidation, in which case holders of claims likely would receive substantially less favorable treatment than they would receive if we were to emerge as a viable, reorganized entity.

Transfers of our equity, or issuances of equity in connection with our restructuring, may impair our ability to utilize our federal income tax net operating loss carryforwards in future years.

Under federal income tax law, a corporation is generally permitted to deduct from taxable income net operating losses carried forward from prior years. We have net operating loss carryforwards of approximately $61,380,000 as of December 31, 2008. Our ability to utilize our net operating loss carryforwards to offset future taxable income and to reduce federal income tax liability is subject to certain requirements and restrictions. If we experience an ownership change, as defined in section 382 of the Internal Revenue Code, then our ability to use our net operating loss carryforwards may be substantially limited, which could have a negative impact on our financial position and results of operations. Generally, there is an ownership change if one or more shareholders owning 5% or more of a corporation s common stock have aggregate increases in their ownership of such stock of more than 50 percentage points over the prior three-year period. Following the implementation a plan of reorganization, it is possible that an ownership change may be deemed to occur. Under section 382 of the Internal Revenue Code, absent an applicable exception, if a corporation undergoes an ownership change, the amount of its net operating losses that may be utilized to offset future taxable income generally is subject to an annual limitation. Notwithstanding the foregoing, even if an ownership change is deemed to occur, the limitation on the utilization of net operating losses may not apply if: (i) the corporation was under the jurisdiction of a case under the Bankruptcy Code, and (ii) the former shareholders and certain qualified creditors of the corporation retain control over the corporation after the ownership change. The section 382 rules governing when an ownership change occurs and whether an exception applies are complex and subject to interpretation.

RISKS RELATED TO OUR BUSINESS

Our debt may negatively impact our liquidity, limit our ability to obtain additional financing and harm our competitive position.

Our debt may have important negative consequences for us, such as:

limiting our ability to obtain additional financing;

limiting funds available for us because we must dedicate a substantial portion of our cash flow from operations to the payment of interest expense, thereby reducing the funds available to us for other purposes, including capital expenditures;

increasing our vulnerability to economic downturns and changing market and industry conditions;

limiting our ability to compete with companies that are not as highly leveraged and that may be better positioned to withstand economic downturns; and limiting the Company s ability to retain existing customers and attract new customers.

We may need to finance ordinary business operations through borrowings under our DIP Credit Agreement. As a result our flexibility in operating our business and our ability to repay our indebtedness may be limited as a result of certain covenant restrictions in the DIP Credit Agreement.

We may need to finance ordinary business operations through borrowings under our DIP Credit Agreement. If we are unable to fully access our DIP Credit Agreement, we may become illiquid and we may be unable to finance our ordinary business activities. The DIP Credit Agreement contains certain restrictive covenants. Compliance with these restrictive covenants will limit our flexibility in operating our business. Failure to comply with these covenants could give rise to an event of default under the DIP Credit Agreement. These covenants restrict, among other things, our ability to:

incur additional indebtedness and guarantee obligations;

create liens;

engage in mergers, consolidations, or liquidations;

sell, lease or otherwise dispose of assets;

change the nature of our business;

make equity investments or loans;

pay dividends, make distributions or redeem any equity securities;

modify our organizational documents or certain debt documents;

change our accounting treatment and reporting practices; and

prepay certain indebtedness.

The Company must comply with various covenants to maintain access to financing under the DIP Credit Agreement and its right to use the pre-petition lenders cash collateral.

If we default on any of the financial or operating covenants in the DIP Credit Agreement and are unable to obtain an amendment or waiver, the lenders could cause all amounts outstanding under the DIP Credit Agreement to be due and payable immediately and the lenders under the DIP Credit Agreement could proceed against the collateral securing that indebtedness.

We may not be able to generate sufficient cash flow to service our outstanding debt and fund operations.

Our ability to satisfy our obligations to pay interest and to repay debt depends on the performance of our business. To the extent that we use a portion of our cash flow from operations to pay the principal of, and interest on, our indebtedness, that cash flow will not be available to fund future operations and capital expenditures. Historically, we have not generated sufficient cash flow from operations to fund both our operations and debt service. Our operating cash flow will not be sufficient to fund our future capital expenditure and debt service requirements or to fund future operations unless we increase revenues significantly. We cannot assure you that we will generate sufficient cash flow from operations to enable us to service or reduce our indebtedness or to fund our other liquidity needs.

We have a limited operating history for you to evaluate our business. We had net losses in recent years and may never attain profitability.

We are engaged in the business of oil and gas exploration and development, and have limited current oil and natural gas operations. The business of acquiring, exploring for, developing and producing oil and natural gas reserves is inherently risky. Our proposed operations are subject to the expenses, difficulties, complications, delays and other risks frequently encountered in connection with the formation of any new business, as well as those risks that are specific to the oil and gas industry. Our business is speculative and dependent upon the implementation of our business plan and our ability to enter into agreements with third parties for the rights to exploit potential oil and natural gas reserves on terms that will be commercially viable for us. Investors should evaluate us in light of these risks.

Our lack of diversification has had a negative effect on our financial condition and results of operations and increases the risk of an investment in Foothills.

Our business focus is on the oil and gas industry in a limited number of properties, currently in California, Oklahoma and Texas. While larger companies have the ability to manage their risk by diversification, we lack diversification, in terms of both the nature and geographic scope of our business. As a result, our financial condition has been impacted more acutely by factors affecting the regions in which we operate than it would have been if our business were more diversified, enhancing our risk profile. If we cannot diversify our operations, our financial condition and results of operations may continue to be negatively affected disproportionately to other companies whose operations are more diversified.

Strategic relationships upon which we may rely are subject to change, which may diminish our ability to conduct our operations.

Our ability to successfully acquire additional properties, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will depend on developing and maintaining close working relationships with industry participants and on our ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment. We may not be able to establish these strategic relationships, or if established, we may not be able to maintain them. In addition, the dynamics of our relationships with strategic partners may require us to incur expenses or undertake activities we would not otherwise be inclined to in order to fulfill our obligations to these partners or maintain our relationships. If we cannot establish and maintain strategic relationships, our business prospects may be limited, which could diminish our ability to conduct our operations.

Competition in obtaining rights to explore and develop oil and gas reserves and to market our production may impair our business.

The oil and gas industry is highly competitive. Other oil and gas companies may seek to acquire oil and gas leases and other properties and services we will need to operate our business in the areas in which we expect to operate. Additionally, other companies engaged in our line of business may compete with us from time to time in obtaining capital from investors. Competitors include larger companies, which, in particular, may have access to greater resources, may be more successful in the recruitment and retention of qualified employees and may conduct their own refining and petroleum marketing operations, which may give them a competitive advantage. In addition, actual or potential competitors may be strengthened through the acquisition of additional assets and interests. If we are unable to compete effectively or adequately respond to competitive pressures, this inability may materially adversely affect our results of operation and financial condition.

Our hedging activities could result in financial losses or could reduce our net income, which may adversely affect an investment in our common stock.

We are contractually obligated by the Pre-Petition Credit Facility to enter into hedging contracts with the purpose and effect of fixing oil and natural gas prices on no less than 50% of projected oil and gas production from our proved developed producing oil and gas reserves. To comply with the requirements of our credit facility, and in order to manage our exposure to price risks in the marketing of our oil and natural gas production, we have entered into oil and natural gas price hedging arrangements with respect to a portion of our expected production. We may enter into additional hedging transactions in the future.

While intended to reduce the effects of volatile oil and natural gas prices, such transactions may limit our potential gains and increase our potential losses if oil and natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement; or
- the counterparties to our hedging agreements fail to perform under the contracts.

The counterparties to our hedging contracts may be entitled to terminate these contracts upon expiration of the Cash Collateral Order. Any termination of our hedging contracts would constitute a default under the Pre-Petition Credit Facility and the DIP Credit Agreement and could negatively impact the cash flow available to fund operations and debt service requirements.

The recent global credit and financial crisis could have adverse effects on the Company.

The current global credit and financial crisis could have significant adverse effects on the Company s operations, including as a result of any of the following:

- downturns in the business or financial condition of any of the Company s key customers or services and equipment providers;
- the creditworthiness of customers, services and equipment providers, and counterparties could deteriorate resulting in a financial loss or a disruption in our access to services and equipment;
- the deterioration of any of the lending parties under the DIP Credit Agreement which could result in such parties failure to satisfy their obligations under their arrangements with the Company; and
- the current lack of available funding sources, which could have a negative impact upon the liquidity of the Company as well as that of its customers or services and equipment providers.

RISKS RELATED TO OUR INDUSTRY

Drilling for oil and gas is risky and may not be commercially successful, and the 3D seismic data and other advanced technologies we use cannot eliminate exploration risk, which could impair our ability to generate revenues from our operations.

Our future success will depend in part on the success of our drilling program. Oil and gas drilling involves a high degree of risk. These risks are more acute in the early stages of exploration. Our expenditures on exploration may not result in new discoveries of oil or natural gas in commercially viable quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions, such as over-pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

Even when used and properly interpreted, 3D seismic data and visualization techniques only assist geoscientists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. In addition, the use of 3D seismic data becomes less reliable when used at increasing depths. We could incur losses as a result of expenditures on unsuccessful wells. If exploration costs exceed our estimates, or if our exploration efforts do not produce results which meet our expectations, our exploration efforts may not be commercially successful, which could adversely impact our ability to generate revenues from our operations.

We may not be able to develop oil and gas reserves on an economically viable basis, and our reserves and production may decline as a result.

If we succeed in discovering oil and/or natural gas reserves, we cannot assure that these reserves will be capable of production levels we project or in sufficient quantities to be commercially viable. On a long-term basis, our viability depends on our ability to find or acquire, develop and commercially produce additional oil and natural gas reserves. Without the addition of reserves through acquisition, exploration or development activities, our reserves and production will decline over time as reserves are produced. Our future reserves will depend not only on our ability to develop then-existing properties, but also on our ability to identify and acquire additional suitable producing properties or prospects, to find markets for the oil and natural gas we develop and to effectively distribute our production into our markets.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-downs of connected wells resulting from extreme weather conditions, problems in storage and distribution and adverse geological and mechanical conditions. While we will endeavor to effectively manage these conditions, we cannot be assured of doing so optimally, and we will not be able to eliminate them completely in any case. Therefore, these conditions could diminish our revenue and cash flow levels and result in the impairment of our oil and natural gas interests.

Estimates of oil and natural gas reserves that we make may be inaccurate and our actual revenues may be lower than our reserve report projections.

We will make estimates of oil and natural gas reserves, upon which we will base our financial projections. We will make these reserve estimates using various assumptions, including assumptions as to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Some of these assumptions are inherently subjective, and the accuracy of our reserve estimates relies in part on the ability of our management team, engineers and other advisors to make accurate assumptions. Economic factors beyond our control, such as interest rates, will also impact the value of our reserves and future cash flows. The process of estimating oil and natural gas reserves is complex, and will require us to use significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property. As a result, our reserve estimates will be inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from those we estimate. If actual production results vary substantially from our reserve estimates, this could materially reduce our revenues and result in the impairment of our oil and natural gas interests.

Drilling new wells could result in new liabilities, which could endanger our interests in our properties and assets.

There are risks associated with the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, premature declines of reservoir pressures, blow-outs, craterings, sour gas releases, fires and spills, among others. The occurrence of any of these events could significantly reduce our revenues or cause substantial losses, impairing our future operating results. We may become subject to liability for pollution, blow-outs or other hazards. We intend to obtain insurance with respect to these hazards; however, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. The payment of such

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liabilities could reduce the funds available to us or could, in an extreme case, result in a total loss of our properties and assets. Moreover, we may not be able to maintain adequate insurance in the future at rates that are considered reasonable. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Decommissioning costs are unknown and may be substantial. Unplanned costs could divert resources from other projects.

We may become responsible for costs associated with abandoning and reclaiming wells, facilities and pipelines which we use for production of oil and natural gas reserves. Abandonment and reclamation of these facilities and the costs associated therewith is often referred to as decommissioning. We expect to satisfy such costs of decommissioning from the proceeds of production in accordance with the practice generally employed in onshore and offshore oilfield operations. If decommissioning is required before economic depletion of our properties or if our estimates of the costs of decommissioning exceed the value of the reserves remaining at any particular time to cover such decommissioning costs, we may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy such decommissioning costs could impair our ability to focus capital investment in other areas of our business.

Our inability to obtain necessary facilities could hamper our operations.

Oil and gas exploration and development activities are dependent on the availability of drilling and related equipment, transportation, power and technical support in the particular areas where these activities will be conducted, and our access to these facilities may be limited. To the extent that we conduct our activities in remote areas, needed facilities may not be proximate to our operations, which will increase our expenses. Demand for such limited equipment and other facilities or access restrictions may affect the availability of such equipment to us and may delay exploration and development activities. The quality and reliability of necessary facilities may also be unpredictable and we may be required to make efforts to standardize our facilities, which may entail unanticipated costs and delays. Shortages and/or the unavailability of necessary equipment or other facilities will impair our activities, either by delaying our activities, increasing our costs or otherwise.

We may have difficulty distributing our production, which could harm our financial condition.

In order to sell the oil and natural gas that we are able to produce, we will have to make arrangements for storage and distribution to the market. We will rely on local infrastructure and the availability of transportation for storage and shipment of our products, but infrastructure development and storage and transportation facilities may be insufficient for our needs at commercially acceptable terms in the localities in which we operate. This could be particularly problematic to the extent that our operations are conducted in remote areas that are difficult to access, such as areas that are distant from shipping and/or pipeline facilities. These factors may affect our ability to explore and develop properties and to store and transport our oil and natural gas production and may increase our expenses. In the Eel River Basin in California, we have contractual rights to access existing natural gas transportation facilities. Depending on the success of any future drilling, it is possible that we will be required to construct additional pipeline facilities in the future in order to have sufficient capacity to transport all of our natural gas production.

Furthermore, weather conditions or natural disasters, actions by companies doing business in one or more of the areas in which we will operate, or labor disputes may impair the distribution of oil and/or natural gas and in turn diminish our financial condition or ability to maintain our operations.

Prices and markets for oil and natural gas are unpredictable and tend to fluctuate significantly, which could reduce profitability, growth and the value of our business.

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond our control. World prices for oil and natural gas have fluctuated widely in recent years, and rose to record levels on a nominal basis in mid-2008 but have declined dramatically since then. As reported by the Energy Information Administration, the average spot price for a barrel of West Texas Intermediate oil was $19.34 in 1999, $26.18 in 2002, and $56.64 in 2005. During 2008, the daily spot price of a barrel of West Texas Intermediate oil peaked at $145.16, and as of March 31, 2009, was reported as $49.64. We expect that prices will fluctuate in the future. Price fluctuations will have a significant impact upon our revenue, the return from our reserves and on our financial condition generally. Price fluctuations for oil and natural gas commodities may also impact the investment market for companies engaged in the oil and gas industry. Prices may not remain at current levels. Future decreases in the prices of oil and natural gas may have a material adverse effect on our financial condition, the future results of our operations and quantities of reserves recoverable on an economic basis.

Increases in our operating expenses will impact our operating results and financial condition.

Exploration, development, production, marketing (including distribution costs) and regulatory compliance costs (including taxes) will substantially impact the net revenues we derive from the oil and natural gas that we produce. These costs are subject to fluctuations and variation in different locales in which we will operate, and we may not be able to predict or control these costs. If these costs exceed our expectations, this may adversely affect our results of operations. In addition, we may not be able to earn net revenue at our predicted levels, which may impact our ability to satisfy our obligations.

Penalties we may incur could impair our business.

Failure to comply with government regulations could subject us to civil and criminal penalties, could require us to forfeit property rights, and may affect the value of our assets. We may also be required to take corrective actions, such as installing additional equipment or taking other actions, each of which could require us to make substantial capital expenditures. We could also be required to indemnify our employees in connection with any expenses or liabilities that they may incur individually in connection with regulatory action against them. As a result, our future business prospects could deteriorate due to regulatory constraints, and our profitability could be impaired by our obligation to provide such indemnification to our employees.

Environmental risks may adversely affect our business.

All phases of the oil and gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner we expect may result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. The application of environmental laws to our business may cause us to curtail our production or increase the costs of our production, development or exploration activities.

Our business will suffer if we cannot obtain or maintain necessary licenses.

Our operations will require licenses, permits and in some cases renewals of licenses and permits from various governmental authorities. Our ability to obtain, sustain or renew such licenses and permits on acceptable terms is subject to change in regulations and policies and to the discretion of the applicable governments, among other factors. Our inability to obtain, or our loss of or denial of extension, to any of these licenses or permits could hamper our ability to produce revenues from our operations.

Challenges to title to our properties may impact our financial condition.

Title to oil and gas interests is often not capable of conclusive determination without incurring substantial expense. While we intend to make appropriate inquiries into the title of properties and other development rights we acquire, title defects may exist. If title defects do exist, it is possible that we may lose all or a portion of our right, title and interests in and to the properties to which the title defects relate.

If our property rights are reduced, our ability to conduct our exploration, development and production activities may be impaired.

We will rely on technology to conduct our business and our technology could become ineffective or obsolete.

We rely on technology, including geological and seismic analysis techniques and economic models, to develop our reserve estimates and to guide our exploration, development and production activities. We will be required to continually enhance and update our technology to maintain its efficacy and to avoid obsolescence. The costs of doing so may be substantial, and may be higher than the costs that we anticipate for technology maintenance and development. If we are unable to maintain the efficacy of our technology, our ability to manage our business and to compete may be impaired. Further, even if we are able to maintain technical effectiveness, our technology may not be the most efficient means of reaching our objectives, in which case we may incur higher operating costs than we would were our technology more efficient.

RISKS RELATED TO OUR COMMON STOCK

There has been a limited trading market for our common stock and no market for our warrants.

There has been a limited trading market for our common stock on the Over-the-Counter Bulletin Board and no established market for the warrants. The lack of an active market may impair the ability of our investors to sell their shares of common stock or their warrants at the time they wish to sell them or at a price that they consider reasonable. An inactive market may also impair our ability to raise capital by selling shares of capital stock and may impair our ability to acquire other companies or technologies by using our common stock as consideration.

You may have difficulty trading and obtaining quotations for our common stock or warrants.

Our common stock is currently quoted on the Over-the-Counter Bulletin Board under the symbol FTRQE.OB. Our warrants do not currently trade on any exchange or market. Our common stock has been actively traded for only a limited time, and the bid and ask prices for our common stock have fluctuated widely. As a result, investors may find it difficult to dispose of, or to obtain accurate quotations of the price of, our common stock and our warrants. This severely limits the liquidity of our common stock and our warrants, and would likely reduce the market price of our common stock and warrants, and hamper our ability to raise additional capital.

The market price of our common stock is, and is likely to continue to be, highly volatile and subject to wide fluctuations.

Based on the terms of the proposed plan of reorganization currently under discussion, we expect our outstanding common stock and warrants and options to purchase shares of common stock will be extinguished. In the event that our existing common stock is not extinguished in the Chapter 11 Cases, there may not be a public market for our securities. To the extent that a public market exists, the market price of our common stock is likely to be highly volatile and be subject to wide fluctuations in response to a number of factors, many of which will be beyond our control.

Our operating results may fluctuate significantly, and these fluctuations may cause the price of our common stock and our warrants to decline.

Our operating results will likely vary in the future primarily as the result of fluctuations in our revenues and operating expenses, including the coming to market of oil and natural gas reserves that we are able to develop, expenses that we incur, the prices of oil and natural gas in the commodities markets and other factors. If our results of operations do not meet the expectations of current or potential investors, the price of our common stock and our warrants may decline.

We do not expect to pay dividends in the foreseeable future.

We do not intend to declare dividends for the foreseeable future, as we anticipate that we will apply any future earnings to retire indebtedness or to invest in the development and growth of our business. Therefore, investors will not receive any funds unless they sell their common stock or warrants, and stockholders may be unable to sell their shares and warrants on favorable terms or at all. Investors cannot be assured of a positive return on investment or that they will not lose the entire amount of their investment in our common stock and warrants.

Stockholders will experience dilution upon the exercise of warrants and options.

As of March 31, 2009, there were 2,289,375 shares of common stock underlying options issued and outstanding and 23,177,691 shares of common stock underlying warrants issued and outstanding, which if exercised or converted, could decrease the net tangible book value of our common stock. In addition, there were 5,000,000 shares of common stock underlying equity-based incentive grants or awards that may be granted or awarded, of which equity-based incentive grants or awards for 624,301 shares of common stock have already been granted, pursuant to the Company s 2007 Equity Incentive Plan. If the holders of those options exercise those options, stockholders may experience dilution in the net tangible book value of our common stock. Further, the sale or availability for sale of the underlying shares in the marketplace could depress our stock price.

Applicable SEC rules governing the trading of penny stocks limit the trading and liquidity of our common stock, which may affect the trading price of our common stock.

Shares of our common stock may be considered a penny stock and be subject to SEC rules and regulations which impose limitations upon the manner in which such shares may be publicly traded and regulate broker-dealer practices in connection with transactions in penny stocks. Penny stocks generally are equity securities with a price of less than $5.00 (other than securities registered on certain national securities exchanges, provided that current price and volume information with respect to transactions in such securities is provided by the exchange). The penny stock rules require a broker-dealer, prior to a transaction in a penny stock not otherwise exempt from the rules, to deliver a standardized risk disclosure document that provides information about penny stocks and the risks in the penny stock market. The broker-dealer must also provide the customer with current bid and offer quotations for the penny stock, the compensation of the broker-dealer and its salesperson in the transaction, and monthly account statements showing the market value of each penny stock held in the customer s account. In addition, the penny stock rules generally require that prior to a transaction in a penny stock, the broker-dealer must make a special written determination that the penny stock is a suitable investment for the purchaser and receive the purchaser s written agreement to the transaction. These disclosure requirements may have the effect of reducing the level of trading activity in the secondary market for a stock that becomes subject to the penny stock rules which may increase the difficulty investors may experience in attempting to liquidate an investment in our common stock or warrants.

Item 2. Properties.

We commenced our present business activities in April 2006. All of the Company s oil and gas exploration, development and production activities are located in the United States. We currently hold interests in properties in the Texas Gulf Coast area, in the Eel River Basin in northern California, and in the Anadarko Basin in western Oklahoma.

Texas

In September 2006, Foothills Texas, Inc. consummated the acquisition of TARH E&P Holdings, L.P. s interests in four oilfields in southeastern Texas. We paid aggregate consideration of $62 million for the properties, comprised of a cash payment of approximately $57.5 million and the issuance of 1,691,186 shares of common stock to TARH E&P Holdings, L.P.

In the acquisition, Foothills Texas acquired interests in four fields: the Goose Creek Field and Goose Creek East Field, both in Harris County, Texas, the Cleveland Field, located in Liberty County, Texas, and the Saratoga

Field located in Hardin County, Texas. These interests represent working interests ranging from 95% to 100% in the four fields.

Following the acquisition, we began an ongoing recompletion program to access proved behind-pipe reserves and increase daily production from the fields. At the date of acquisition, more than 70 recompletion opportunities in existing wells had been identified, and we have subsequently identified additional zones for recompletion. Through December 31, 2008, 30 recompletions had been conducted, of which 10 were undertaken in 2008. As of December 31, 2008, we had more than 60 remaining recompletion opportunities.

After drilling three successful development wells in the Goose Creek Field in 2007, we initiated a comprehensive geological remapping of the field during the third quarter of 2008. This in-depth study, which has not yet been completed and was interrupted by the initiation of the Chapter 11 proceeding, resulted in increases in proved and probable reserves attributable to existing development well locations and the identification of new development well locations. Additionally the study was intended to enhance the understanding of deeper potential production targets such as the Vicksburg, Yegua and Wilcox formations, either where one or more of these formations are present below the existing producing formations and above the top of the Goose Creek salt dome or where they may be present on the unexplored flanks of the salt dome underlying the field.

In September 2008, the eye of Hurricane Ike passed directly over the Goose Creek Field. Although our facilities suffered relatively minor damage, our production from the Texas fields was completely shut down for almost two weeks due to the extensive power outage in the region. Our production from the four fields averaged 503 barrels of oil and oil-equivalent natural gas per day (boepd) in 2008, down by 3% from 2007 principally due to the shut-down caused by Hurricane Ike. We expect to average over 500 boepd in 2009.

California

Eel River Basin

The Eel River Basin is the northernmost of the California sedimentary basins. Most of the basin exists offshore of northern California and southern Oregon. However, a portion of the basin is present onshore in Humboldt County, California. Hydrocarbons generated in the deeper offshore part of the basin have migrated updip into the Miocene and Pliocene rocks present in this area. The onshore portion of the basin contains the Tompkins Hill natural gas field that was discovered by Texaco in 1937. It is now owned and operated by Vintage Petroleum (Occidental), has produced in excess of 120 billion cubic feet of natural gas, and is continuing to produce.

The Grizzly Bluff area within the Eel River Basin (approximately five miles south of the Tompkins Hill Field) was initially proven to contain natural gas in three wells drilled by Zephyr in the mid-1960s. These wells tested gas at rates of 1.9 to 5 million cubic feet of gas per day. In the early 1970s, Chevron drilled a deep well seeking oil but found strong indications of natural gas. In the late 1980s and early 1990s, ARCO drilled several wells and found natural gas in the shallow zones, one of which tested gas at rates of up to 2.2 million cubic feet of gas per day. None of these wells were put into production due to the lack of a natural gas market and pipeline connection, and all of them were subsequently abandoned.

In the past decade, we believe the industry has overlooked the hydrocarbon potential and production within the Eel River Basin due to its relatively isolated position in California. INNEX Energy, L.L.C. recognized this overlooked potential in the form of multiple low resistivity, low contrast sands that possibly define part of a widespread, basin-centered natural gas play. INNEX Energy, L.L.C. began acquiring oil and gas leases in the area in 2000 to test this concept and entered into a joint venture with Forexco, Inc. in 2002. A subsequent 10-well drilling program in 2003 by Forexco, Inc. encountered drilling and completion problems, but established production from six wells in the Grizzly Bluff area, three of which are now producing approximately 300 thousand cubic feet of gas per day. This field was brought on line in late 2003 with the completion of a natural gas gathering system and a new pipeline that connects to the PG&E Corporation backbone grid for northern California. INNEX Energy, L.L.C. and Forexco, Inc. terminated their joint venture in 2004.

The Tompkins Hill Field is the analog field in the basin for the Eel River Project. The distance between the Tompkins Hill Field and the Grizzly Bluff Field is approximately five miles. This production is from similar age rocks at similar depths as the Grizzly Bluff Prospect, the first prospect that we drilled in the Eel River Project. Our mapping indicates that substantial natural gas reserves occur above the lowest tested gas in the Grizzly Bluff Field in multiple stacked Pliocene sandstone reservoirs.

In January 2006, Foothills California, Inc. entered into a Farmout and Participation Agreement with INNEX California, Inc., a subsidiary of INNEX Energy, L.L.C., to acquire, explore and develop oil and natural gas properties located in the Eel River Basin. The Farmout and Participation Agreement expired in 2008 upon the completion of our obligations under the agreement. The material terms of the agreement were as follows:

We serve as operator of a joint venture with INNEX California, Inc., and had the right to earn an interest in approximately 4,000 existing leasehold acres held by INNEX California, Inc. in the basin, and to participate as operator with INNEX California, Inc. in oil and gas acquisition, exploration and development activities within an area of mutual interest consisting of the entire Eel River Basin.

The agreement provided for drill-to-earn terms, and consisted of three phases.

In Phase I, we were obligated to pay 100% of the costs of drilling two shallow wells on the Grizzly Bluff Prospect, acquiring 1,000 acres of new leases, and certain other activities. We fulfilled our obligations under Phase I, and received an assignment from INNEX California, Inc. of a 75% working interest (representing an approximate 56.3% net revenue interest) in the leases held by INNEX California, Inc. in the two drilling units to the deepest depth drilled in the two Phase I obligation wells.

We then had the option, but not the obligation, to proceed into Phase II. We elected to proceed into Phase II and paid the costs of conducting a 3D seismic survey covering approximately 12.7 square miles on the Grizzly Bluff Prospect and of drilling one additional shallow well. We fulfilled our obligations under Phase II, and received an assignment from INNEX California, Inc. of a 75% working interest (representing an approximate 56.3% net revenue interest) in the leases held by INNEX California, Inc. in the drilling unit for the well drilled in Phase II and a 75% working interest (representing an approximate 59.3% net revenue interest) in all remaining leases held by INNEX California, Inc. to the deepest depth drilled in the three Phase I and II obligation wells.

We then had the option, but not the obligation, to proceed into Phase III. We elected to proceed into Phase III, and paid 100% of the costs of drilling one deep well on the Grizzly Bluff Prospect. We fulfilled our obligations under Phase III, and received an assignment from INNEX California, Inc. of a 75% working interest (representing an approximate 56.3% net revenue interest) in the leases held by INNEX California, Inc. in the drilling unit and a 75% working interest (representing an approximate 59.3% net revenue interest) in all remaining leases held by INNEX California, Inc. with no depth limitation.

Following the completion of Phase III, the Farmout and Participation Agreement expired, and the two parties are each responsible for funding their working interest share of the joint venture s costs and expenses. We generally have a 75% working interest in activities conducted on specified prospects existing at the time of execution of the agreement, and a 70% working interest in other activities. Each party will be able to elect not to participate in exploratory wells on a prospect-by-prospect basis, and a non-participating party will lose the opportunity to participate in development activities and all rights to production relating to that prospect.

We were also entitled to a proportionate assignment from INNEX California, Inc. of its rights to existing permits, drill pads, roads, rights-of-way, and other infrastructure, as well as its pipeline access and marketing arrangements.

INNEX California, Inc. had an option to participate for a 25% working interest in certain producing property acquisitions by us in the area of mutual interest.

To fulfill our drilling obligations to INNEX, we drilled the Christiansen 3-15 and Vicenus 1-3 wells in 2006, and the GB 4 and GB 5 wells in late 2007 and early 2008, all in the Grizzly Bluff Field. We also re-entered and deepened the Vicenus 1-3 well in late 2007. Results from two of the three wells drilled in late 2007 and early 2008 are still inconclusive, and we are continuing to assess information gained from the ongoing testing program in the Vicenus 1-3 and GB 4 wells. From time to time, we are continuing to test these wells into the gas sales pipeline, but overall the test results and gas production from these wells have been substantially below our expectations.

We were encouraged by test rates in the Lower Rio Dell (LRD) 16 zone in the GB 4 well completed in June 2008, and believe this zone is a viable candidate for a future re-entry and redrill attempt. Although the shallower LRD zones in the well initially produced natural gas at rates up to 500 thousand cubic feet per day (Mcfd), this flow rate has not been sustainable. We have been able to flow the well on an intermittent basis at that rate while also recovering slugs of drilling mud and fluid believed responsible for damaging the formation during drilling and completion operations. We have recently hooked up the GB 4 well to allow further testing of the LRD horizons into the gas sales pipeline. It is anticipated that this well will be produced intermittently as conditions warrant while we attempt to remediate suspected formation damage.

The Vicenus 1-3 well responded to the fracture stimulation conducted in June 2008 to correct formation damage by flowing back gas and water from the LRD 15 and 16 zones below 5,800 feet. The well initially tested a small volume of natural gas. However, because of the excessive volumes of produced water, the well is presently shut-in.

We continue to monitor the GB 5 well that was fracture-stimulated in June 2008 in the Lower Anderson zone to correct formation damage. However, the well did not respond to the frac, and it appears that the zone is either severely damaged or is of very low permeability at this location.

The poorer-than-anticipated results and higher than expected costs of the three wells drilled in late 2007 and early 2008 were principal factors resulting in our non-compliance with the asset coverage and leverage ratio covenants of our Pre-Petition Credit Facility as of March 31, 2008 and June 30, 2008 (see Item 7. Management s Discussion and Analysis or Plan of Operation), as well as a significant downward revision in our net proved and proved developed reserves as of December 31, 2008 (see the Supplemental Oil and Gas Information in our Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data).

In January 2008, the Environmental Impact Report prepared for Humboldt County and the California Coastal Commission was fully approved. This document defines environmental and operating terms and conditions in the Grizzly Bluff area and will regulate any future drilling activity in the field.

Our net production from the Grizzly Bluff Field, which is primarily from the Christiansen 3-15 well, averaged 196 Mcfd in 2008, down by 46% from 2007 principally as a result of contractual cost recovery provisions and normal production declines. We expect our net production to average between 120 Mcfd and 160 Mcfd in 2009.

Our exploration mapping in the Eel River Basin has developed several additional prospects with attractive potential in other parts of the basin. Leases have been acquired over these prospects, and we plan to offer them for participation by industry partners.

Oklahoma

Anadarko Basin

The Anadarko Basin in western Oklahoma and the Texas panhandle is one of the most prolific oil and natural gas producing basins in the United States. Most of the shallow shelf portion of the basin can be characterized as very mature. We believe that much promise remains in the deeper portion of the basin that is characterized by stratigraphic traps in the Pennsylvanian Morrow formation and structural traps in the Ordovician

Hunton formation, two of the formations targeted by the Company. However, to produce oil and natural gas from these deeper formations, drilling is more expensive and the 3D seismic data is less reliable than in the shallow shelf portion of the basin.

The initial focus of our activities within the Anadarko Basin has been the area covered by a 75 square mile 3D seismic survey in Roger Mills County, Oklahoma. We have reprocessed the 3D survey, completed geological and geophysical interpretations of the survey data, and identified drillable prospects. We have secured acreage over several identified high impact prospects, and plan to market the prospects to industry partners.

Oil and Gas Reserves

The following table presents our net proved and proved developed reserves as of December 31, 2008, and the standardized measure of discounted future net cash flows from those reserves. All of our oil and gas properties are located in the United States.

	California	Texas	Total
Total Proved Reserves:			
Oil (Bbls)		2,803,972	2,803,972
Gas (Mcf)	559,794	217,235	777,029
Total barrels of oil equivalent (BOE)	93,299	2,840,178	2,933,477
Total Proved Developed Reserves:			
Oil (Bbls)		2,708,265	2,708,265
Gas (Mcf)	559,794	217,235	777,029
Total barrels of oil equivalent (BOE)	93,299	2,744,271	2,837,570
Standardized measure of discounted net cash flow (in thousands)			$ 25,607

Foothills estimates of proved reserves for the year ended December 31, 2008, were taken from independent evaluations prepared in accordance with the requirements established by the SEC by Cawley, Gillespie and Associates, Inc.

Net Quantities of Oil and Gas Produced

The following table summarizes sales volumes, sales prices and production cost information for our net oil and gas production for the years ended December 31, 2008, 2007 and 2006:

	2008	2007	2006
Net sales volumes:			
Oil (Bbls)	182,774	185,110	69,973
Gas (Mcf)	79,136	135,146	30,135
Total (BOE)	195,963	207,634	74,995
Daily average net sales volumes:			
Oil (Bbls)	499	507	574[1]
Gas (Mcf)	216	370	247[1]
Total (BOE)	535	569	615[1]
Average sales price:			
Oil (per Bbl), excluding the effects of price risk management activities	$ 99.21	$ 77.62	$ 58.17
Oil (per Bbl), including the effects of price risk management activities	$ 75.40	$ 76.54	$ 63.09
Gas (per Mcf)	$ 8.41	$ 7.42	$ 6.34
Average production costs (per BOE):			
Lease operating expense	$ 19.01	$ 17.10	$ 11.61
Severance and ad valorem taxes	$ 6.25	$ 6.34	$ 6.17
Marketing and transportation expense	$ 0.25	$ 0.32	$ 0.18
Total average production costs	$ 25.51	$ 23.76	$ 17.96

Productive Wells

The following table summarizes productive wells as of December 31, 2008:

	Number of Wells					
	Oil		Natural Gas		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
California			1	0.8	1	0.8
Texas	72	71.9			72	71.9
Total	72	71.9	1	0.8	73	72.7

(1) Represents the total number of wells at each property.

(2) Represents our interests in the total number of wells at each property.

[1] Daily average sales volumes for 2006 are based on the period from September 1, 2006, through December 31, 2006. The effective date of the acquisition of the Texas oil and gas properties was September 1, 2006, and production activities in California were commenced in September 2006.

Developed and Undeveloped Acreage

The following table summarizes developed and undeveloped acreage as of December 31, 2008:

	Acres					
	Developed		Undeveloped		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
California	1,089	817	14,694	10,777	15,783	11,594
Oklahoma			257	257	257	257
Texas	2,547	2,519	320	320	2,867	2,839
Total	3,636	3,336	15,138	11,221	18,650	14,433

(1) Represents the total acreage at each property.

(2) Represents our interests in the total acreage at each property.

Drilling Activity

The following table sets forth certain information regarding our drilling activities for the periods indicated:

	Year Ended December 31, 2008		Year Ended December 31, 2007		Period from Commencement of Present Business Activities in April 2006 through December 31, 2006	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Exploration:						
Productive					2	1.5
Dry						
Development:						
Productive			3	3.0		
Dry						
Total						
Productive			3	3.0	2	1.5
Dry						

(1) Represents the total number of wells for which there was drilling activity.

(2) Represents our interests in the total number of wells for which there is drilling activity.

Present Activities

As of December 31, 2008, three gross (2.3 net) wells in California (the Vicenus 1-3 re-entry and deepened well, the GB 5 development well and the GB 4 exploratory well) had been drilled with inconclusive results. We are continuing to assess information gained from the testing program in the Vicenus 1-3 and GB 4 wells. We are continuing to test the GB 4 well into the gas sales pipeline, but overall the test results and gas production from these wells have been substantially below our expectations.

We were encouraged by test rates in the LRD 16 zone in the GB 4 well completed in June 2008, and believe this zone is a viable candidate for a future re-entry and redrill attempt. Although the shallower LRD zones in the well initially produced natural gas at rates up to 500 Mcfd, this flow rate has not been sustainable. We were able to flow the well on an intermittent basis at that rate while also recovering slugs of drilling mud and fluid believed responsible for damaging the formation during drilling and completion operations, and have hooked up the well to allow further testing of the LRD horizons into the gas sales pipeline as conditions warrant. It is anticipated that this well will be produced intermittently as conditions warrant while we attempt to remediate suspected formation damage.

The Vicenus 1-3 well responded to the fracture stimulation conducted in June 2008 to correct formation damage by flowing back gas and water from the LRD 15 and 16 zones below 5,800 feet. We continued to test the well for several months, and the small volumes of produced gas were sold into the gas pipeline, with produced water disposed of in a local facility. The well is presently shut-in.

We continue to monitor the GB 5 well that was fracture-stimulated in June 2008 in the Lower Anderson zone to correct formation damage. However, the well did not respond to the frac, and it appears that the zone is either severely damaged or is of very low permeability at this location. The well is presently shut-in.

Our Offices

Our principal executive offices are located at 4540 California Avenue, Suite 550, Bakersfield, California 93309 and our phone number is (661) 716-1320. We currently lease approximately 4,500 square feet of office space.

Item 3. Legal Proceedings.

As discussed in Item 1 above, on February 11, 2009, we, together with our subsidiaries, filed voluntary petitions for reorganization relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. The Chapter 11 Cases are being jointly administered under the caption *Foothills Texas, Inc., et al., Debtors, Chapter 11 Case No. 09-10452 (CSS)*. We continue to operate our business as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with applicable provisions of the Bankruptcy Code and the orders of the Bankruptcy Court.

From time to time we may become a party to litigation or other legal proceedings that, in the opinion of our management are part of the ordinary course of our business. Other than the Chapter 11 bankruptcy proceedings, which we described above, no legal proceedings or claims are pending against or involve us that, in the opinion of our management, could reasonably be expected to have a material adverse effect on our business, prospects, financial condition or results of operations.

There are limitations on the ability of claimants to bring legal action against us during the pendency of the Chapter 11 proceedings. Absent an order from the Bankruptcy Court, no party, subject to certain exceptions, may take any action, also subject to certain exceptions, to recover on pre-petition claims against us.

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

None.

PART II.

Item 5. Market for Registrant s Common Equity, Related Stockholders Matters and Issuer Purchases of Equity Securities.

Our common stock has been quoted on the Over-the-Counter Bulletin Board under the symbol FTRQE.OB since December 23, 2004, and has been actively traded since April 7, 2006. The following table shows, for the periods indicated since January 1, 2007, the high and low closing sales prices of our common stock:

Fiscal Period	High	Low
2008:		
Fourth Quarter 2008	$0.08	$0.01
Third Quarter 2008	$0.45	$0.06
Second Quarter 2008	$1.09	$0.43
First Quarter 2008	$1.04	$0.51
2007:		
Fourth Quarter 2007	$1.11	$0.79
Third Quarter 2007	$1.32	$0.81
Second Quarter 2007	$1.50	$0.86
First Quarter 2007	$2.10	$1.02

As of March 31, 2009, there were approximately 166 holders of record of shares of our common stock.

On April 30, 2009, the Board voted to voluntarily deregister the Company s common stock under the Exchange Act and become a non-reporting company. On or about May 11, 2009, the Company intends to file with the SEC a Form 15, Notice of Termination of Registration and Suspension of Duty to File, to terminate its reporting obligations under the Exchange Act. Once the Company files the Form 15, its obligation to file reports and other information under the Exchange Act, such as Forms 10-K, 10-Q and 8-K will be suspended. The deregistration of the Company s common stock under the Exchange Act will become effective 90 days after the date on which the Form 15 is filed. The Company is eligible to deregister under the Exchange Act because its common stock is held of record by fewer than 300 persons.

Dividend Policy

We have never declared or paid dividends on shares of our common stock and we intend to retain future earnings, if any, to support the development of our business and therefore do not anticipate paying cash dividends for the foreseeable future. Payment of future dividends, if any, will be at the discretion of our board of directors after taking into account various factors, including current financial condition, operating results and current and anticipated cash needs.

Securities Authorized for Issuance Under Equity Compensation Plans

The following information is provided as of December 31, 2008, with respect to equity compensation plans:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuances Under Equity Compensation Plans (excluding securities reflected in column (a))
Equity Compensation Plans Approved by Security Holders	483,125	$ 0.14	4,375,699
Equity Compensation Plans Not Approved by Security Holders			2,000,000
Total	483,125	$ 0.14	6,375,699

For information regarding securities issued under our equity compensation plans, see Note 5 to our accompanying consolidated financial statements contained in Item 8. Financial Statements and Supplementary Data.

Recent Sales of Unregistered Securities

Other than information previously reported, there have been no sales of unregistered securities within the last three years which would be required to be disclosed pursuant to Item 701 of Regulation S-K.

Item 6. Selected Financial Data.

As a smaller reporting company, we are not required to provide the information required by this Item pursuant to Item 301(c) of Regulation S-K.

Item 7. Management s Discussion and Analysis or Plan of Operation.

This discussion contains statements that constitute forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934 and Section 27A of the Securities Act of 1933. The words expect, estimate, anticipate, predict, believe and similar expressions and variations thereof are intended to identify forward-looking statements. These statements appear in a number of places in this discussion and include statements regarding the intent, belief or current expectations of Foothills Resources, Inc., our directors or officers with respect to, among other things, (a) trends affecting our financial condition or results of operation, (b) our ability to meet our debt service obligations, and (c) our business and growth strategies. Readers are cautioned not to put undue reliance on these forward-looking statements. These forward-looking statements are not guarantees of future performance and involve risks and uncertainties, and actual results may differ materially from those projected in this report. Although we believe that the expectations reflected in our forward-looking statements are reasonable, actual results could differ materially from those projected or assumed. Our future financial condition, as well as any forward-looking statements, are subject to change and to inherent risks and uncertainties, including those disclosed in this report. We undertake no obligation to publicly revise these forward-looking statements to reflect events or circumstances that arise after the date hereof.

General

The following discussion provides information on our financial condition, liquidity and capital resources as of December 31, 2008, and the results of operations for the years ended December 31, 2008, 2007 and 2006. The financial statements and notes thereto contain detailed information that should be referred to in conjunction with this discussion.

The profitability of our operations in any particular accounting period will be directly related to the realized prices of oil and gas sold, the type and volume of the oil and gas produced, and the results of development, exploitation, acquisition, exploration and hedging activities. The realized prices for oil will be predominantly influenced by global supply and demand, while natural gas prices will fluctuate from one period to another due to regional market conditions and other factors. The aggregate amount of oil and gas produced may fluctuate based on the success and timing of development and exploitation of oil and gas reserves pursuant to current reservoir management and our ability to deliver our production to a purchaser. Our production rates, labor, equipment costs, maintenance expenses, and production and ad valorem taxes are expected to be the principal influences on operating costs. Accordingly, our results of operations may fluctuate from period to period based on the foregoing principal factors, among others.

Subsequent to December 31, 2008, prices for natural gas have continued to decline. If commodity prices continue to decline, we could incur a ceiling limitation write-down in future periods under applicable accounting rules. Under these rules, if the net capitalized costs of oil and gas properties exceed a ceiling limit, we must charge the amount of the excess to earnings. This charge does not impact cash flow from operating activities, but does reduce our stockholders equity and earnings. The risk that we will be required to write-down the carrying value of oil and gas properties increases when crude oil and natural gas prices are low. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves.

Overview

Foothills Resources, Inc. (Foothills), a Nevada corporation, and its subsidiaries are collectively referred to herein as we or the Company. The Company is engaged in the acquisition, exploration, exploitation and development of oil and natural gas properties. We currently hold interests in properties in the Texas Gulf Coast area, in the Eel River Basin in northern California, and in the Anadarko Basin in western Oklahoma.

Texas

In September 2006, we consummated the acquisition of TARH E&P Holdings, L.P. s interests in four oilfields in southeastern Texas: the Goose Creek Field and Goose Creek East Field, both in Harris County, Texas, the Cleveland Field, located in Liberty County, Texas, and the Saratoga Field located in Hardin County, Texas. These interests represent working interests ranging from 95% to 100% in the four fields.

Following the acquisition, we established and initiated an ongoing recompletion program to access proved behind-pipe reserves and increase daily production from the fields. At the date of acquisition, more than 70 recompletion opportunities in existing wells had been identified, and we have subsequently identified additional zones for recompletion. Through December 31, 2008, 30 recompletions had been conducted, of which 10 were undertaken in 2008. As of December 31, 2008, we had more than 60 remaining recompletion opportunities.

After drilling three successful development wells in the Goose Creek Field in 2007, we initiated a comprehensive geological remapping of the field during the third quarter of 2008. This in-depth study, which has not yet been completed and was interrupted by the initiation of the Chapter 11 proceeding, resulted in increases in proved and probable reserves attributable to existing development well locations and the identification of new development well locations. Additionally the study was intended to enhance the understanding of deeper potential production targets such as the Vicksburg, Yegua and Wilcox formations, either where one or more of these formations are present below the existing producing formations and above the top of the Goose Creek Salt dome or where they may be present on the unexplored flanks of the salt dome underlying the field.

In September 2008, the eye of Hurricane Ike passed directly over the Goose Creek Field. Although our facilities suffered relatively minor damage, our production from the Texas fields was completely shut down for almost two weeks due to the extensive power outage in the region. Our production from the four fields averaged 503 barrels of oil and oil-equivalent natural gas per day (boepd) in 2008, down by 3% from 2007 principally due to the shut-down caused by Hurricane Ike. We expect to average over 500 boepd in 2009.

California

In January 2006, we entered into a Farmout and Participation Agreement with INNEX California, Inc., a subsidiary of INNEX Energy, L.L.C. (INNEX), to acquire, explore and develop oil and natural gas properties located in the Eel River Basin. The Farmout and Participation Agreement expired in 2008 upon the completion of our obligations under the agreement. The material terms of the agreement were as follows:

We serve as operator of a joint venture with INNEX, and had the right to earn an interest in approximately 4,000 existing leasehold acres held by INNEX in the basin, and to participate as operator with INNEX in oil and gas acquisition, exploration and development activities within an area of mutual interest consisting of the entire Eel River Basin.

The agreement provided for drill-to-earn terms, and consisted of three phases.

In Phase I, we were obligated to pay 100% of the costs of drilling two shallow wells, acquiring 1,000 acres of new leases, and certain other activities. The Company fulfilled its obligations under Phase I, and received an assignment from INNEX of a 75% working interest (representing an approximate 56.3% net revenue interest) in the leases held by INNEX in the two drilling units to the deepest depth drilled in the two Phase I obligation wells.

We then had the option, but not the obligation, to proceed into Phase II. We elected to proceed into Phase II, and paid the costs of conducting a 3D seismic survey covering approximately 12.7 square miles and of drilling one additional shallow well. The Company fulfilled its obligations under Phase II, and received an assignment from INNEX of a 75% working interest (representing an approximate 56.3% net revenue interest) in the leases held by INNEX in the drilling unit for the well drilled in Phase II and a 75% working interest (representing an approximate 59.3% net revenue interest) in all remaining leases held by INNEX to the deepest depth drilled in the three Phase I and II obligation wells.

We then had the option, but not the obligation, to proceed into Phase III. We elected to proceed into Phase III, and paid 100% of the costs of drilling one deep well. The Company fulfilled its obligations under Phase III, and received an assignment from INNEX of a 75% working interest (representing an approximate 56.3% net revenue interest) in the leases held by INNEX in the drilling unit and a 75% working interest (representing an approximate 59.3% net revenue interest) in all remaining leases held by INNEX with no depth limitation.

Following the completion of Phase III, the Farmout and Participation Agreement expired, and the two parties are each responsible for funding their working interest share of the joint venture s costs and expenses. We generally have a 75% working interest in activities conducted on specified prospects existing at the time of execution of the agreement, and a 70% working interest in other activities. Each party will be able to elect not to participate in exploratory wells on a prospect-by-prospect basis, and a non-participating party will lose the opportunity to participate in development activities and all rights to production relating to that prospect.

We were also entitled to a proportionate assignment from INNEX of its rights to existing permits, drill pads, roads, rights-of-way, and other infrastructure, as well as its pipeline access and marketing arrangements.

INNEX had an option to participate for a 25% working interest in certain producing property acquisitions by the Company in the area of mutual interest.

To fulfill our drilling obligations to INNEX, we drilled the Christiansen 3-15 and Vicenus 1-3 wells in 2006, and the GB 4 and GB 5 wells in late 2007 and early 2008, all in the Grizzly Bluff Field. We also re-entered and deepened the Vicenus 1-3 well in late 2007. Results from two of the three wells drilled in late 2007 and early 2008 are still inconclusive, and we are continuing to assess information gained from the testing program in the Vicenus 1-3 and GB 4 wells. We are continuing to test the GB 4 well into the gas sales pipeline, but overall the test results and gas production from these wells have been substantially below our expectations.

We were encouraged by test rates in the Lower Rio Dell (LRD) 16 zone in the GB 4 well completed in June 2008, and believe this zone is a viable candidate for a future re-entry and redrill attempt. Although the shallower LRD zones in the well initially produced natural gas at rates up to 500 thousand cubic feet per day (Mcfd), this flow rate has not been sustainable. We were able to flow the well on an intermittent basis at that rate while also recovering slugs of drilling mud and fluid believed responsible for damaging the formation during drilling and completion operations, and have hooked up the well to allow further testing of the LRD horizons into the gas sales pipeline. It is anticipated that this well will be produced intermittently as conditions warrant while we attempt to remediate suspected formation damage.

The Vicenus 1-3 well responded to the fracture stimulation conducted in June 2008 to correct formation damage by flowing back gas and water from the LRD 15 and 16 zones below 5,800 feet. We continued to test the well for several months, and the small volumes of produced gas were sold into the gas pipeline, with produced water disposed of in a local facility.

We continue to monitor the GB 5 well that was fracture-stimulated in June 2008 in the Lower Anderson zone to correct formation damage. However, the well did not respond to the frac, and it appears that the zone is either severely damaged or is of very low permeability at this location.

Our production from the Grizzly Bluff Field, which is primarily from the Christiansen 3-15 well, averaged 196 Mcfd in 2008, down by 46% from 2007 principally as a result of contractual cost recovery provisions and normal production declines. We expect production to average between 120 Mcfd and 160 Mcfd in 2009.

Our exploration mapping in the Eel River Basin has developed several additional prospects with attractive potential in other parts of the basin. We plan to offer these prospects for participation by industry partners.

Oklahoma

The initial focus of our activities within the Anadarko Basin has been the area covered by a 75 square mile 3D seismic survey in Roger Mills County, Oklahoma. We have reprocessed the 3D survey, completed geological and geophysical interpretations of the survey data, and identified drillable prospects. We have secured acreage over several identified high impact prospects, and plan to market the prospects to industry partners.

Liquidity and Capital Resources

Substantial capital is required to replace and grow reserves. Material increases or decreases in our liquidity are determined by the cash flow from our producing properties, the success or failure of our drilling activities, and our ability to access debt or equity capital markets.

These sources can be impacted by significant fluctuations in oil and gas prices, operating costs, and volumes produced, the general condition of our industry and the global credit crisis. We have no control over the market prices for oil and natural gas, although we are able to influence the amount of our net realized revenues related to oil and gas sales through the use of derivative contracts. A decrease in oil and gas prices would reduce expected cash flow from operating activities.

In December 2007, we entered into a Credit Agreement with various lenders and Wells Fargo Foothill, LLC, as agent (the Pre-Petition Credit Facility). The Pre-Petition Credit Facility provides for a $50,000,000 term loan facility and a $50,000,000 revolving credit facility, with an initial borrowing base of $25,000,000 available under the revolving credit facility. The Pre-Petition Credit Facility matures in December 2012, with principal payments scheduled to commence in April 2010 based on 50% of our cash flow, net of capital expenditures. The Pre-Petition Credit Facility has restrictions on the operations of our business, including restrictions on payment of dividends. Borrowings under the term loan facility carry prepayment penalties ranging from 1.00% to 2.00% in the first three years of the Pre-Petition Credit Facility. Borrowings under the revolving credit facility may be repaid at any time without penalty. The Pre-Petition Credit Facility is secured by liens and security interests on substantially all of our assets, including 100% of our oil and gas reserves.

We used a portion of the proceeds of the Pre-Petition Credit Facility to retire amounts outstanding under a secured promissory note in the principal amount of $42,500,000 under a previous credit facility (the Mezzanine Facility). Although we recorded a loss of $17,593,000 in connection with the early retirement of the Mezzanine Facility, including $10,164,000 in prepayment penalties and transaction costs, and $7,429,000 of non-cash charges relating to the unamortized balances of debt discount and debt issue costs, we entered into the Pre-Petition Credit Facility and retired the Mezzanine Facility because we expected the Pre-Petition Credit Facility to provide us with significant liquidity for development activities, a substantial reduction in our weighted average cost of debt capital, increased operating flexibility through an improved covenant package, and enhanced ability to manage our cash position (and interest costs) through the revolving structure.

The Pre-Petition Credit Facility contains financial covenants pertaining to asset coverage, interest coverage and leverage ratios. A violation of any of these financial covenants, unless waived by our lenders, constitutes an event of default under the Pre-Petition Credit Facility, giving our lenders the right to terminate their obligations to make additional loans under the Pre-Petition Credit Facility, demand immediate payment in full of all amounts outstanding, foreclose on collateral and exercise other rights and remedies granted under the Pre-Petition Credit Facility and as may be available pursuant to applicable law. As of March 31, 2008, we were not in compliance with the leverage ratio covenant. We entered into a First Amendment to Credit Agreement, dated as of May 15, 2008, by and among the Company, the lenders and the agent, and a Limited Waiver and Second Amendment to Credit Agreement, dated as of May 15, 2008, by and among the Company, the lenders and the agent, pursuant to which the lenders waived non-compliance with the leverage ratio covenant, and the interest rate on the term loan facility was modified to provide that it will not be less than 10.50% in the event that the London Interbank Offered Rate (LIBOR) is less than 4.00%.

As of June 30, 2008, we were not in compliance with the asset coverage and leverage ratio covenants of our Pre-Petition Credit Facility, and were in default under the Pre-Petition Credit Facility. We obtained a forbearance agreement from the lenders under our Pre-Petition Credit Facility, pursuant to which the lenders agreed to forbear from exercising certain of their rights and remedies resulting from our noncompliance with the asset coverage and leverage ratio covenants of the Pre-Petition Credit Facility until September 15, 2008. The forbearance agreement was later extended until December 31, 2008.

As of December 31, 2008, the amounts outstanding under the Pre-Petition Credit Facility consisted of approximately $52,807,000 under the term loan facility, including $2,807,000 in forbearance fees and interest added to the principal outstanding, and approximately $23,540,000 under the revolving loan facility. We have reclassified our long-term debt as a current liability.

The poorer-than-anticipated results and higher than expected costs of the three wells drilled in California in late 2007 and early 2008 (see Item 2. Properties) were principal factors resulting in our non-compliance with the asset coverage and leverage ratio covenants of our Pre-Petition Credit Facility as of March 31, 2008 and June 30, 2008, as well as a significant downward revision in our net proved and proved developed reserves (see the Supplemental Oil and Gas Information in our Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data). Pursuant to the forbearance and waiver agreements with the lenders under our Pre-Petition Credit Facility, we retained Parkman Whaling LLC (Parkman) in August 2008 to assist in the evaluation of various strategic alternatives, including a potential sale of our assets. Parkman established both an electronic and a physical data room. Parkman contacted approximately 51 companies, of which 17 companies attended data room presentations. In December 2008, eight parties submitted proposals to purchase some or all of our properties or to acquire the Company. None of the proposed purchase prices or acquisition terms was acceptable to us or to the lenders under our Pre-Petition Credit Facility. We believe that the unsatisfactory results are attributable principally to the unprecedented drop in oil and natural gas prices between July 2008 and December 2008, and the global collapse of the equity and credit markets in the fourth quarter of 2008.

Consequently, on February 11, 2009, we, along with each of our subsidiaries, filed voluntary petitions for reorganization relief under Chapter 11 (the Chapter 11 Cases) of the United States Bankruptcy Code (the Bankruptcy Code) in the United States Bankruptcy Court for the District of Delaware (the Bankruptcy Court). The Chapter 11 Cases are being jointly administered under the caption *Foothills Texas, Inc., et al., Debtors, Chapter 11 Case No. 09-10452 (CSS).*

We intend to maintain business operations through the reorganization process. However, our liquidity and capital resources are significantly affected by the Chapter 11 Cases. Our Chapter 11 proceedings have resulted in various restrictions on our activities, limitations on financing and a need to obtain Bankruptcy Court approval for various matters. As a result of the filing of the Chapter 11 Cases, we are not permitted to make any payments on pre-petition liabilities without prior Bankruptcy Court approval. However, we have been granted relief in order to continue wage and salary payments and other benefits to employees as well as other related pre-petition obligations; and to continue to honor certain pre-petition obligations. Under the priority schedule established by the Bankruptcy Code, certain post-petition and pre-petition liabilities need to be satisfied before general unsecured creditors and equity holders are entitled to receive any distribution. At this time, it is not possible to predict with certainty the effect of the Chapter 11 Cases on our business or various creditors, or when we will emerge from these Chapter 11 proceedings. Our future results depend upon the successful implementation, on a timely basis, of a plan of reorganization. The continuation of the Chapter 11 Cases, particularly if a plan of reorganization is not timely approved or confirmed, could further adversely affect our operations. See Item 1. Business and Item 1A. Risk Factors.

In connection with the Chapter 11 Cases, on February 23, 2009, we entered into the DIP Credit Agreement with the lenders who are parties thereto (the Lenders), Regiment Capital Special Situations Fund III, L.P., as agent, and our subsidiaries, as guarantors (the DIP Credit Agreement). The Bankruptcy Court approved the DIP Credit Agreement on an interim basis on February 12, 2009 and entered the final approval order on March 3, 2009.

The DIP Credit Agreement provides for revolving loans up to an aggregate of $2.5 million (the Loans). The proceeds of the Loans will be used for working capital purposes, including the payment of fees, costs, and expenses incurred in connection with the DIP Credit Agreement and for expenditures consistent with a budget agreed upon by the Company and the Lenders pursuant to the DIP Credit Agreement. Interest will accrue under the DIP Credit Agreement at 12% per annum, provided however, following an event of default under the DIP Credit Agreement, interest will accrue at an annual rate equal to 2% above the annual rate otherwise applicable. The obligations under the DIP Credit Agreement are secured, subject to certain limited exceptions, by substantially all of the assets of the Company, including a super-priority administrative expense claim pursuant to Bankruptcy Code Section 364(c)(1). Absent a further order from the Bankruptcy Court approving an extension of the maturity date, the Loans will mature on the earliest of:

- May 19, 2009,
- the date of substantial consummation of a plan or reorganization in the Chapter 11 Cases that has been confirmed by an order of the Bankruptcy Court,
- the date of a sale of substantially all of the assets of the Company, and
- such earlier date on which all Loans and other obligations for the payment of money shall become due and payable in accordance with the terms of the DIP Credit Agreement.

We have obtained court authorization to use cash, negotiable instruments, documents of title, securities, deposit accounts, and other cash equivalents (Cash Collateral) which are subject to security interest pursuant to the Pre-Petition Credit Facility and the DIP Credit Agreement.

We have requested Bankruptcy Court approval to extend the maturity date of the Loans and the authorization to use the Cash Collateral through and including August 19, 2009. A hearing will be held on this request on May 12, 2009.

Going Concern Matters

The financial statements and related notes accompanying this Form 10-K have been prepared assuming that we will continue as a going concern. The financial statements do not include any adjustments relating to the recoverability and classification of recorded assets, or the amounts and classification of liabilities that might be necessary in the event that we cannot continue in existence. However, the Chapter 11 Cases raise substantial doubt about our ability to continue as a going concern. Our continuation as a going concern is contingent upon, among other things, our ability (i) to comply with the terms of the DIP Credit Agreement; (ii) to reduce administrative, operating and interest costs and liabilities through the bankruptcy process; (iii) to generate sufficient cash flow from operations; (iv) to obtain confirmation of a plan of reorganization under the Bankruptcy Code, and (v) to obtain financing in order to exit from bankruptcy. In the event our restructuring activities are not successful and we are required to liquidate, additional significant adjustments will be necessary in the carrying value of assets and liabilities.

Results of Operations

The following table summarizes sales volumes, sales prices, and production cost information for the Company s net oil and gas production for the years ended December 31, 2008, 2007 and 2006:

	2008	2007	2006
Annual net sales volumes:			
Oil (Bbls)	182,774	185,110	69,973
Gas (Mcf)	79,136	135,146	30,135
Total (BOE)	195,963	207,634	74,996
Daily average net sales volumes:			
Oil (Bbls)	499	507	574[1]
Gas (Mcf)	216	370	247[1]
Total (BOE)	535	569	615[1]
Average sales price:			
Oil (per Bbl), excluding the effects of price risk management activities	$ 99.21	$ 77.62	$ 58.17
Oil (per Bbl), including the effects of price risk management activities	$ 75.40	$ 76.54	$ 63.09
Gas (per Mcf)	$ 8.41	$ 7.32	$ 6.54
Average production costs (per BOE):			
Lease operating expense	$ 19.01	$ 16.98	$ 11.61
Severance and ad valorem taxes	$ 6.25	$ 6.33	$ 6.35
Marketing and transportation expense	$ 0.25	$ 0.32	$ 0.18
Total average production costs	$ 25.51	$ 23.63	$ 17.95

Barrels of oil-equivalent (BOE) were determined using a ratio of six Mcf of natural gas to one Bbl of crude oil.

Year Ended December 31, 2008 compared with the Year Ended December 31, 2007

The Company reported a net loss of $59,527,000, or $0.98 per basic and diluted share, for the year ended December 31, 2008, compared to a net loss of $26,028,000, or $0.43 per basic and diluted share, for the year ended December 31, 2007.

[1] Daily average sales volumes for 2006 are based on the period from

September 1, 2006, through December 31, 2006. The effective date of the acquisition of the Texas oil and gas properties was September 1, 2006, and production activities in California were commenced in September 2006.

Oil and Gas Revenues. Oil and gas revenues for 2008 decreased to $14,439,000 from $15,171,000 in 2007. The decrease in oil and gas revenues resulted primarily from increased losses on the settlement of hedging instruments due to increases in world oil prices as well as decreases in production, the effect of which was partially offset by higher realized commodity prices. Oil and gas production volumes declined in 2008 principally because the Company s production from its Texas fields was completely shut down for almost two weeks in September due to the extensive power outage in the region caused by Hurricane Ike. Gas production volumes also declined in 2008 due to the reduction of the Company s net revenue interest in the Christiansen 3-15 well in the Grizzly Bluff Field as a result of contractual cost recovery provisions, and normal production declines. The effect of these factors was partially offset by oil production from new wells drilled in the Goose Creek Field in the fourth quarter of 2007.

Production Costs. Total production costs, including lease operating and workover expenses, marketing and transportation expenses, and production and ad valorem taxes, increased to $4,999,000 for the year ended December 31, 2008, from $4,907,000 for the year ended December 31, 2007. The increase in production costs resulted primarily from an increase in the number of workovers and well servicing operations. Production costs per BOE were also higher as a result of the decline in production volumes.

General and Administrative Expenses. General and administrative expenses increased to $3,612,000 in 2008 from $3,374,000 in 2007 primarily because of increased professional fees resulting from the Company s evaluation of strategic alternatives.

Interest Expense. The Company incurred net interest expense of $8,137,000, including $1,318,000 of non-cash charges for the amortization of debt discount and debt issue costs, during the year ended December 31, 2008. The decrease from $10,205,000, including $3,609,000 of non-cash charges for the amortization of debt discount and debt issue costs, for 2007 resulted primarily from a reduction in the Company s cost of debt capital attributable to the consummation of the Pre-Petition Credit Facility, as hereinafter defined, and the retirement of amounts outstanding under a previous credit facility in December 2007, the effect of which was partially offset by higher levels of debt outstanding in 2008.

Liquidated Damages. Liquidated damages relate to amounts payable to our stockholders as a result of the registration statements for our securities issued in 2006 not becoming effective within the periods specified in the share registration rights agreements for those securities. For the year ended December 31, 2008, the expenses reflected in our results of operations for these liquidated damages decreased to $1,000 from $2,591,000 for the year ended December 31, 2007, because of provisions in the registration rights agreements limiting the maximum amount of such damages.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization increased to $5,968,000, including $5,785,000 ($29.52 per BOE) for the capitalized costs of oil and gas properties, for the year ended December 31, 2008, from $2,785,000, including $2,614,000 ($12.59 per BOE) for the capitalized costs of oil and gas properties, for the year ended December 31, 2007, primarily as a result of a downward revision in estimates of proved oil and gas reserves and increases in the capitalized costs of oil and gas properties, the effects of which were partially offset by decreases in production during 2008.

Ceiling Write-Down of Oil & Gas Properties. We recorded a ceiling write-down of oil and gas properties amounting to $50,991,000 in 2008. Under the full-cost method of accounting, if the net capitalized costs of oil and gas properties in a cost center exceed an amount equal to the sum of the present value of estimated future net revenues from proved oil and gas reserves in the cost center and the costs of properties not being amortized, both adjusted for income tax effects, such excess is charged to expense. The present value of estimated future net revenues from our proved oil and gas reserves declined in 2008 as a result of a downward revision in estimates of proved oil and gas reserves and the effect of lower commodity prices as of December 31, 2008, as compared to December 31, 2007.

Year Ended December 31, 2007 compared with the Year Ended December 31, 2006

The Company reported a net loss of $26,028,000, or $0.43 per basic and diluted share, for the year ended December 31, 2007, compared to a net loss of $3,764,000, or $0.09 per basic and diluted share, for the year ended December 31, 2006.

Oil and Gas Revenues. Oil and gas revenues for 2007 increased to $15,171,000 from $4,605,000 in 2006. The increase in oil and gas revenues resulted primarily from the acquisition of producing properties in the Texas Gulf Coast area in September 2006 (the Texas Acquisition), as well as the effect of higher realized commodity prices.

Production Costs. Total production costs, including lease operating and workover expenses, marketing and transportation expenses, and production and ad valorem taxes, increased to $4,907,000 for the year ended December 31, 2007, from $1,346,000 for the year ended December 31, 2006. The increase in production costs resulted primarily from the Texas Acquisition.

General and Administrative Expenses. General and administrative expenses increased to $3,374,000 in 2007 from $3,352,000 in 2006 primarily as a result of expansion of the Company s staff and facilities, the effect of which was partially offset by a decrease in investor relations expense in connection with the Company s commencement of its present business activities in 2006.

Interest Expense. The Company incurred interest expense of $10,205,000, including $3,609,000 of non-cash charges for the amortization of debt discount and debt issue costs, during the year ended December 31, 2007. The increase from $3,090,000, including $1,165,000 of non-cash charges for the amortization of debt discount and debt issue costs, for 2006 resulted from $42,500,000 in borrowings in September 2006 for the Texas Acquisition.

Liquidated Damages. Liquidated damages of $2,591,000 in 2007 relate to amounts payable to our stockholders as a result of the registration statements for our securities issued in 2006 not becoming effective within the periods specified in the share registration rights agreements for those securities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization increased to $2,785,000, including $2,614,000 ($12.59 per BOE) for the capitalized costs of oil and gas properties, for the year ended December 31, 2007, from $829,000, including $775,000 ($10.33 per BOE) for the capitalized costs of oil and gas properties, for the year ended December 31, 2006, primarily as a result of increases in production attributable to the Texas Acquisition.

Loss on Early Extinguishment of Debt. During 2007, the Company recorded a loss of $17,593,000 in connection with the early retirement of a previous credit facility, including $7,429,000 of non-cash charges relating to the unamortized balances of debt discount and debt issue costs.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Described below are the most significant policies we apply in preparing our financial statements, some of which are subject to alternative treatments under generally accepted accounting principles. We also describe the most significant estimates and assumptions we make in applying these policies.

Oil and Gas Properties Accounting

We follow the full-cost method of accounting for oil and gas properties. Under this method, all productive and nonproductive costs incurred in connection with the acquisition, exploration and development of oil and gas reserves are capitalized in separate cost centers for each country in which we have operations. Such capitalized costs include leasehold acquisition, geological, geophysical and other exploration work, drilling, completing and equipping oil and gas wells, asset retirement costs, internal costs directly attributable to property acquisition, exploration and development, and other related costs. We also capitalize interest costs related to unevaluated oil and gas properties.

The capitalized costs of oil and gas properties in each cost center are amortized using the unit-of-production method. Sales or other dispositions of oil and gas properties are normally accounted for as adjustments of capitalized costs. Gains or losses are not recognized in income unless a significant portion of a cost center s reserves is involved. Capitalized costs associated with the acquisition and evaluation of unproved properties are excluded from amortization until it is determined whether proved reserves can be assigned to such properties or until the value of the properties is impaired. Unproved properties are assessed at least annually to determine whether any impairment has occurred. If the net capitalized costs of oil and gas properties in a cost center exceed an amount equal to the sum of the present value of estimated future net revenues from proved oil and gas reserves in the cost center and the costs of properties not being amortized, both adjusted for income tax effects, such excess is charged to expense.

Oil and Gas Reserves

The process of estimating quantities of natural gas and crude oil reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in the financial statement disclosures. We use the unit-of-production method to amortize our oil and gas properties. This method requires us to amortize the capitalized costs incurred in proportion to the amount of oil and gas produced as a percentage of the amount of proved reserves. Accordingly, changes in reserve estimates as described above will cause corresponding changes in depreciation, depletion and amortization expense recognized in periods subsequent to the reserve estimate revision. Reserve estimates as of December 31, 2008, 2007 and 2006 were provided by Cawley, Gillespie & Associates, Inc.

Asset Retirement Obligations

We have significant obligations related to the plugging and abandonment of our oil and gas wells, and the removal of equipment and facilities from leased acreage and returning such land to its original condition. We estimate the future cost of this obligation, discounted to its present value, and record a corresponding liability and asset in our consolidated balance sheets. The values ultimately derived are based on many significant estimates, including the ultimate expected cost of the obligation, the expected future date of the required cash payment, and interest and inflation rates. Revisions to these estimates may be required based on changes to cost estimates, the timing of settlement, and changes in legal requirements. Any such changes that result in upward or downward revisions in the estimated obligation will result in an adjustment to the liability with the offset to the related capitalized asset on a prospective basis.

Price Risk-Management Activities

We periodically enter into commodity derivative contracts to manage our exposure to oil price volatility. We currently utilize only price swaps, which are placed with Wells Fargo Bank, N.A. The oil reference prices of these commodity derivatives contracts are based upon the New York Mercantile Exchange, and have a high degree of historical correlation with actual prices we receive. We account for our derivative instruments in accordance with Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS No. 133). SFAS No. 133 establishes accounting and reporting standards requiring that all derivative instruments, other than those that meet the normal purchases and sales exception, be recorded on the balance sheet as either an asset or liability measured at fair value (which is generally based on information obtained from independent parties). SFAS No. 133 also requires that changes in fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Hedge accounting treatment allows unrealized gains and losses on cash flow hedges to be deferred in other comprehensive income. Realized gains and losses from our oil and gas cash flow hedges, including terminated contracts, are generally recognized in oil and gas revenues when the forecasted transaction occurs. Gains and losses from the change in fair value of derivative instruments that do not qualify for hedge accounting are reported in current period income. If at any time the likelihood of occurrence of a hedged forecasted transaction ceases to be probable, hedge accounting under SFAS No. 133 will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings. Amounts recorded in other comprehensive income prior to the change in the likelihood of occurrence of the forecasted transaction will remain in other comprehensive income until such time as the forecasted transaction impacts earnings. If it becomes probable that the original forecasted production will not occur, then the derivative gain or loss would be reclassified from accumulated other comprehensive income into earnings immediately. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time, and any ineffectiveness is immediately reported in the consolidated statement of operations.

Valuation of Deferred Tax Assets

We utilize the liability method of accounting for income taxes, as set forth in SFAS No. 109, Accounting for Income Taxes. Under the liability method, deferred taxes are determined based on the difference between the financial statement and tax bases of assets and liabilities using enacted tax rates in effect in the years in which the differences are expected to reverse. Valuation allowances are recorded against deferred tax assets when it is considered more likely than not that the deferred tax assets will not be utilized.

Stock-Based Compensation

Effective January 1, 2006, we adopted SFAS No. 123 (revised 2004), Share-Based Payment (SFAS No. 123R), which replaced SFAS No. 123, Accounting for Stock-Based Compensation, and superseded Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees. SFAS No. 123R requires companies to measure the cost of stock-based compensation granted, including stock options and restricted stock, based on the fair market value of the award as of the grant date, net of estimated forfeitures. We had no stock-based compensation grants prior to January 1, 2006.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Hedging Transactions

In connection with our credit facility with Wells Fargo Foothill, LLC, we are contractually obligated to enter into hedging contracts with the purpose and effect of fixing oil and natural gas prices on no less than 50% of projected oil and gas production from our proved developed producing oil and gas reserves. To fulfill our hedging obligation, we have entered into swap agreements with Wells Fargo Bank, N.A. We have entered into the swaps with Wells Fargo Bank, N.A. to hedge the price risks associated with a portion of our anticipated future oil and gas production through September 30, 2010, mitigating a portion of our exposure to adverse market changes and allowing us to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Our swap agreements have not been entered into for trading purposes and we have the ability and intent to hold these instruments to maturity. Wells Fargo Bank, N.A., the counterparty to the swap agreements, is also an affiliate of our lender under a credit facility. We believe that the terms of the swap agreements are at least as favorable as we could have achieved in swap agreements with third parties who are not our lenders.

By removing a significant portion of the price volatility from our future oil and gas revenues through the swap agreements, we have mitigated, but not eliminated, the potential effects of changing oil and gas prices on our cash flows from operations through September 30, 2010. While these and other hedging transactions we may enter into in the future will mitigate our risk of declining prices for oil and gas, they will also limit the potential gains that we would experience if prices in the market exceed the fixed prices in the swap agreements. We have not obtained collateral to support the agreements but monitor the financial viability of our counterparty and believe our credit risk is minimal on these transactions. Under these arrangements, payments are received or made based on the differential between fixed product prices in the swap agreements and a variable product price representing the average of the closing settlement price(s) on the New York Mercantile Exchange for futures contracts for the applicable trading months. These agreements are settled in cash at monthly expiration dates. In the event of nonperformance, we would be exposed again to price risk. We have some risk of financial loss because the price received for the oil or gas production at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the hedging transaction. We could also suffer financial losses if our actual oil and gas production is less than the hedged production volumes during periods when the variable product price exceeds the fixed product price. Moreover, our hedge arrangements generally do not apply to all of our production and thus provide only partial price protection against declines in commodity prices. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time, and any ineffectiveness is immediately reported in the consolidated statement of operations.

Our current hedging transactions are designated as cash flow hedges, and we record the costs and any benefits derived from these transactions as a reduction or increase, as applicable, in natural gas and oil sales revenue. We may enter into additional hedging transactions in the future.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

As a smaller reporting company, we are not required to provide the information required by this Item pursuant to Item 305(e) of Regulation S-K.

Item 8. Financial Statements and Supplementary Data.

FOOTHILLS RESOURCES, INC. AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Shareholders of Foothills Resources, Inc.

We have audited the accompanying balance sheets of Foothills Resources, Inc. (a Nevada corporation) as of December 31, 2008 and 2007, and the related statements of operations, stockholders equity and cash flows, for the years ended December 31, 2008, 2007 and 2006. The Company s management is responsible for these financial statements. 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 financial statements referred to above present fairly, in all material respects, the financial position of Foothills Resources, Inc. as of December 31, 2008 and 2007, and the results of its operations and its cash flows for the years ended December 31, 2008, 2007 and 2006 in conformity with accounting principles generally accepted in the United States of America.

The accompanying financial statements have been prepared assuming the Company will continue as a going concern. As described in Note 1 to the financial statements, the Company s voluntary petitions for reorganization relief under Chapter 11 of the United States Bankruptcy Code raise substantial doubt about its ability to continue as a going concern, unless the Company is able to have a successful implementation, on a timely basis, of a plan of reorganization. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

BROWN ARMSTRONG PAULDEN
McCOWN STARBUCK THORNBURGH & KEETER
ACCOUNTANCY CORPORATION
April 27, 2009
Bakersfield, California

FOOTHILLS RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(dollars in thousands, except per share amounts)

	December 31, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 29	$ 165
Accounts receivable	1,114	1,880
Prepaid expenses	181	212
Fair value of derivative financial instruments	2,016	
	3,340	2,257
Property and equipment, at cost:		
Oil and gas properties, using full-cost accounting -		
Proved properties	90,516	75,215
Unproved properties not being amortized	898	760
Other property and equipment	503	533
	91,917	76,508
Less accumulated depreciation, depletion and amortization	(60,456)	(3,554)
	31,461	72,954
Other assets	6,299	3,413
	$ 41,100	$ 78,624
LIABILITIES AND STOCKHOLDERS EQUITY (DEFICIT)		
Current liabilities:		
Current portion of long-term debt	$ 74,546	$
Accounts payable and accrued liabilities	2,186	5,669
Fair value of derivative financial instruments		3,228
Liquidated damages	2,593	2,591
	79,325	11,488
Long-term debt		52,243
Asset retirement obligations	809	628

Fair value of derivative financial instruments		3,571
Stockholders equity (deficit):		
Preferred stock, $0.001 par value 25,000,000 shares authorized, none issued and outstanding		
Common stock, $0.001 par value 250,000,000 shares authorized, 60,557,637 and 60,572,442 shares issued and outstanding at December 31, 2008 and 2007	61	61
Additional paid-in capital	47,576	47,224
Accumulated deficit	(89,049)	(29,792)
Accumulated other comprehensive income (loss)	2,378	(6,799)
	(39,034)	10,694
	$ 41,100	$ 78,624

The accompanying notes are an integral part of these consolidated financial statements.

FOOTHILLS RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(dollars in thousands, except per share amounts)

	Year Ended December 31, 2008	2007	2006
Income:			
Oil and gas revenues	$ 14,439	$ 15,171	$ 4,605
Interest income	12	256	248
	14,451	15,427	4,853
Expenses:			
Production costs	4,999	4,907	1,346
General and administrative	3,612	3,374	3,352
Interest	8,137	10,205	3,090
Liquidated damages	1	2,591	
Depreciation, depletion and amortization	5,968	2,785	829
Ceiling write-down of oil and gas properties	50,991		
Loss on early extinguishment of debt		17,593	
	73,708	41,455	8,617
Net loss	$ (59,257)	$ (26,028)	$ (3,764)
Basic and diluted net loss per share	$ (0.98)	$ (0.43)	$ (0.09)
Weighted average number of common shares outstanding basic and diluted	60,561,561	60,454,510	43,966,775

The accompanying notes are an integral part of these consolidated financial statements.

FOOTHILLS RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(dollars in thousands)

	Year Ended December 31,		
	2008	**2007**	**2006**
Cash flows from operating activities:			
Net loss	$ (59,257)	$ (26,028)	$ (3,764)
Adjustments to reconcile net loss to net cash used for operating activities -			
Stock-based compensation	450	500	388
Depreciation, depletion and amortization	5,913	2,741	815
Accretion of asset retirement obligation	55	44	14
Non-cash interest expense	242		
Amortization of discount on long-term debt	456	3,370	1,101
Amortization of debt issue costs	862	239	64
Ceiling write-down of oil and gas properties	50,991		
Casualty loss	30		
Loss on early extinguishment of debt		7,429	
Changes in assets and liabilities -			
Accounts receivable	766	(429)	(1,452)
Prepaid expenses	32		(212)
Other assets	3	35	
Accounts payable and accrued liabilities	(173)	451	1,557
Liquidated damages	1	2,591	
Net cash provided by (used for) operating activities	371	(9,057)	(1,489)
Cash flows from investing activities:			
Additions to oil and gas properties	(18,636)	(7,850)	(64,656)
Additions to other property and equipment	(2)	(58)	(476)
Decrease in other assets			(79)
Net cash used for investing activities	(18,638)	(7,908)	(65,211)
Cash flows from financing activities:			
Proceeds of borrowings	31,590	56,000	42,500
Repayments of borrowings	(13,135)	(44,000)	
Debt issuance costs	(238)	(3,433)	(685)
Members capital contributions			50
Proceeds from issuance of common stock and warrants			35,616
Stock issuance costs	(86)	(110)	(2,108)
Net cash provided by financing activities	18,131	8,457	75,373
Net increase (decrease) in cash and cash equivalents	(136)	(8,508)	8,673

Cash and cash equivalents at beginning of the period		165		8,673		
Cash and cash equivalents at end of the period	$	29	$	165	$	8,673
Supplemental disclosures of cash flow information:						
Cash paid for -						
Interest	$	6,251	$	6,370	$	1,816
Income taxes						
Noncash investing activities -						
Net increases (decreases) in accrued capital expenditures		(3,322)		2,618		1,014
Oil and gas properties acquired for common stock				223		4,174

The accompanying notes are an integral part of these consolidated financial statements.

FOOTHILLS RESOURCES, INC.
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY (DEFICIT)
(dollars in thousands, except per share amounts)

	Common Stock						
	Number	Par Value	Additional Paid-in Capital	Members Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2005		$	$	$ 50	$	$	$ 50
Contributions				50			50
Exchange of members capital for common shares and conversion from limited liability company to corporation	17,375,000	17	83	(100)			
Issuance of common stock and warrants	42,112,753	42	42,972				43,014
Exercise of warrants	889,076	1	888				889
Stock-based compensation			388				388
Change in fair value of derivative financial instruments						1,595	1,595
Net loss					(3,764)		(3,764)
Balance, December 31, 2006	60,376,829	60	44,331		(3,764)	1,595	42,222

The accompanying notes are an integral part of these consolidated financial statements.

FOOTHILLS RESOURCES, INC.
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY (DEFICIT)
(dollars in thousands, except per share amounts)

	Common Stock Number	Common Stock Par Value	Additional Paid-in Capital	Members Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total
Issuance of common stock and warrants	85,841		2,504				2,504
Stock-based compensation	109,772	1	499				500
Change in fair value of derivative financial instruments						(8,394)	(8,394)
Stock issuance costs			(110)				(110)
Net loss					(26,028)		(26,028)
Balance, December 31, 2007	60,572,442	61	47,224		(29,792)	(6,799)	10,694
Stock-based compensation	(14,805)		438				438
Change in fair value of derivative financial instruments						9,177	9,177
Stock issuance costs			(86)				(86)
Net loss					(59,257)		(59,257)
Balance, December 31, 2008	60,557,637	$ 61	$ 47,576	$	$ (89,049)	$ 2,378	$ (39,034)

The accompanying notes are an integral part of these consolidated financial statements.

FOOTHILLS RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2008

Note 1 General

Summary of Operations

Foothills Resources, Inc. (Foothills), a Nevada corporation, and its subsidiaries are collectively referred to herein as the Company. The Company is a growth-oriented independent energy company engaged in the acquisition, exploration, exploitation and development of oil and natural gas properties. The Company currently holds interests in properties in the Texas Gulf Coast area, in the Eel River Basin in northern California, and in the Anadarko Basin in southwest Oklahoma.

Foothills took its current form on April 6, 2006, when Brasada California, Inc. (Brasada) merged with and into an acquisition subsidiary of Foothills. Brasada was formed on December 29, 2005, as Brasada Resources LLC, a Delaware limited liability company, and converted to a Delaware corporation on February 28, 2006. Following the merger, Brasada changed its name to Foothills California, Inc. (Foothills California) and is now a wholly owned operating subsidiary of Foothills. This transaction was accounted for as a reverse takeover of the Company by Foothills California. The Company adopted the assets, management, business operations and business plan of Foothills California. The financial statements of the Company prior to the merger were eliminated at consolidation.

Chapter 11 Cases

On February 11, 2009, Foothills and each of its subsidiaries (collectively the Debtors) filed voluntary petitions for reorganization relief under Chapter 11 (the Chapter 11 Cases) of the United States Bankruptcy Code (the Bankruptcy Code) in the United States Bankruptcy Court for the District of Delaware (the Bankruptcy Court). The Chapter 11 Cases are being jointly administered under the caption *Foothills Texas, Inc., et al., Debtors, Chapter 11 Case No. 09-10452 (CSS).*

The Company continues to operate its business as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with applicable provisions of the Bankruptcy Code and the orders of the Bankruptcy Court. There can be no assurance that the Debtors will be able to successfully develop, execute, confirm and consummate one or more plans of reorganization with respect to the Chapter 11 Cases that are acceptable to the Bankruptcy Court and the Debtors creditors and other parties in interest.

The Company intends to maintain its business operations through the reorganization process. Liquidity and capital resources, however, are significantly affected by the Chapter 11 Cases. The Chapter 11 Cases have resulted in various restrictions on the Company s activities, limitations on financing and a need to obtain Bankruptcy Court approval for various matters. As a result of the filing of the Chapter 11 Cases, the Company is not permitted to make any payments on pre-petition liabilities without prior Bankruptcy Court approval (see Note 3). However, the Company has been granted relief in order to continue wage and salary payments and other benefits to employees as well as other related pre-petition obligations; to continue to honor certain pre-petition obligations; and to pay certain pre-petition claims held by critical vendors. Under the priority schedule established by the Bankruptcy Code, certain post-petition and pre-petition liabilities need to be satisfied before general unsecured creditors and equity holders are entitled to receive any distribution. At this time, it is not possible to predict with certainty the effect of the Chapter 11 Cases on the Company s business or various creditors, or when the Debtors will emerge from these proceedings. The Company s future results depend upon the confirmation and successful implementation, on a timely basis, of a plan of reorganization. The continuation of the Chapter 11 Cases, particularly if a plan of reorganization is not timely approved or confirmed, could further adversely affect the Company s operations.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. The financial statements do not include any adjustments relating to the recoverability and classification of recorded assets, or the amounts and classification of liabilities that might be necessary in the event the Company cannot continue in existence. However, the Chapter 11 Cases raise substantial doubt about the Company s ability to continue as a going concern. The Company s continuation as a going concern is contingent upon, among other things, its ability (i) to comply with the terms of the DIP Credit Agreement (see Note 12); (ii) to reduce administrative, operating and interest costs and liabilities through the bankruptcy process; (iii) to generate sufficient cash flow from operations; (iv) to obtain confirmation of a plan of reorganization under the Bankruptcy Code; and (v) to obtain financing in order to exit from bankruptcy. In the event the Company s restructuring activities are not successful and it is required to liquidate, additional significant adjustments will be necessary to the carrying value of assets and liabilities.

Note 2 Significant Accounting Policies

Principles of consolidation

The consolidated financial statements include the accounts of Foothills and its wholly owned subsidiaries. All material intercompany accounts and transactions have been eliminated in consolidation. The Company accounts for its investments in oil and gas joint ventures using the proportionate consolidation method, whereby the Company s proportionate share of each venture s assets, liabilities, revenues and expenses is included in the appropriate classification in the financial statements.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the amounts reported in the financial statements. Actual results could differ from such estimates. Changes in such estimates may affect amounts reported in future periods.

Cash and cash equivalents

Cash and cash equivalents include cash on hand and on deposit, and highly liquid debt instruments with original maturities of three months or less.

Oil and gas properties

The Company follows the full-cost method of accounting for oil and gas properties. Under this method, all productive and nonproductive costs incurred in connection with the acquisition, exploration and development of oil and gas reserves are capitalized in separate cost centers for each country in which the Company has operations. Such capitalized costs include leasehold acquisition, geological, geophysical and other exploration work, drilling, completing and equipping oil and gas wells, asset retirement costs, internal costs directly attributable to property acquisition, exploration and development, and other related costs. The Company also capitalizes interest costs related to unevaluated oil and gas properties.

The capitalized costs of oil and gas properties in each cost center are amortized using the unit-of-production method. Sales or other dispositions of oil and gas properties are normally accounted for as adjustments of capitalized costs. Gains or losses are not recognized in income unless a significant portion of a cost center s reserves is involved. Capitalized costs associated with the acquisition and evaluation of unproved properties are excluded from amortization until it is determined whether proved reserves can be assigned to such properties or until the value of the properties is impaired. Unproved properties are assessed at least annually to determine whether any impairment has occurred. If the net capitalized costs of oil and gas properties in a cost center exceed an amount equal to the sum of the present value of estimated future net revenues from proved oil and gas reserves in the cost center and the costs of properties not being amortized, both adjusted for income tax effects, such excess is charged to expense.

During 2008, the Company completed the drilling of two wells in the Eel River Basin in California. After perforating the indicated gas-bearing zones in both wells, the Company did not recover natural gas from either well.

The Company believed this result was inconsistent with the mud log shows, electric log interpretations, and the offsetting well information. The Company s conclusion was that polymer fluids used during drilling operations most likely damaged the reservoirs near the wellbores. The Company subsequently attempted to fracture the formations beyond the damaged zones in the wells. Following these operations, the Company was unable to produce natural gas in commercial quantities from either well, and revised its estimates of gas reserves as of December 31, 2008, by eliminating all proved developed and undeveloped reserves attributable to these formations. The costs incurred for drilling these wells have been included in costs subject to amortization as of December 31, 2008. In addition, the prices of oil and natural gas declined significantly during the third and fourth quarters of 2008. As of December 31, 2008, the prices used in computing the estimated future net cash flows from the Company s proved reserves, excluding the effect of hedges in place as of December 31, 2008, averaged $43.87 per barrel of oil and $5.53 per thousand cubic feet of natural gas. As a result of these downward revisions of proved oil and gas reserves and lower commodity prices, and their negative impact on the Company s proved reserves and estimated future net revenues, the Company recognized a ceiling write-down of oil and gas properties of $50,991,000 during 2008. The Company s cash flow hedges in place as of December 31, 2008, reduced the ceiling write-down by approximately $4,745,000.

Other property and equipment

Other property and equipment consists of computer hardware and software, office furniture and equipment, vehicles, buildings and leasehold improvements, and are depreciated on a straight-line basis over their estimated useful lives ranging from three to 40 years.

Other assets

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized to interest expense over the term of the related agreement, using the interest method.

Asset retirement obligations

The fair value of an asset retirement obligation (ARO) is recognized in the period in which it is incurred if a reasonable estimate can be made. The Company s ARO primarily relates to the abandonment of oil and gas wells and producing facilities. Inherent in the fair value calculation of the ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO, a corresponding adjustment is made to the capitalized costs of oil and gas properties. The following table sets forth a reconciliation of the beginning and ending ARO for the years ended December 31, 2008 and 2007 (in thousands):

	2008	**2007**
Asset retirement obligation, beginning of year	$ 628	$ 570
Liabilities incurred	126	14
Accretion expense	55	44
Asset retirement obligation, end of year	$ 809	$ 628

Income taxes

The Company utilizes the liability method of accounting for income taxes, as set forth in Statement of Financial Accounting Standards (SFAS) No. 109, Accounting for Income Taxes. Under the liability method, deferred taxes are determined based on the difference between the financial statement and tax bases of assets and liabilities using enacted tax rates in effect in the years in which the differences are expected to reverse. Valuation allowances are recorded against deferred tax assets when it is considered more likely than not that the deferred tax assets will not be utilized.

Revenue recognition

Oil and gas revenues from producing wells are recognized when title and risk of loss is transferred to the purchaser of the oil or gas.

Stock-based compensation

Effective January 1, 2006 the Company adopted SFAS No. 123 (revised 2004), Share-Based Payment (SFAS 123R), which replaced SFAS No. 123, Accounting for Stock-Based Compensation, and superseded Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees. SFAS 123R requires companies to measure the cost of stock-based compensation granted, including stock options and restricted stock, based on the fair market value of the award as of the grant date, net of estimated forfeitures. The Company had no stock-based compensation grants prior to January 1, 2006.

Earnings per common share

Basic earnings per share is computed by dividing net income or loss by the weighted average number of shares of common stock outstanding during the period. Diluted earnings per share is determined on the assumption that outstanding stock options and warrants have been converted using the average price for the period. For purposes of computing earnings per share in a loss period, potential common shares are excluded from the computation of weighted average common shares outstanding if their effect is antidilutive. For the years ended December 31, 2008, 2007 and 2006, potential common stock equivalents of 5,252,013, 3,506,114 and 9,153,812, respectively, have been excluded from the calculations because their effect would have been antidilutive.

Fair value of financial instruments

For cash and cash equivalents, receivables and payables, the carrying amounts approximate fair value because of the short maturity of these instruments. Long-term debt is variable rate debt and as such, approximates fair value, as interest rates are variable based on prevailing market rates.

Derivative instruments and hedging activities

The Company accounts for its derivative instruments in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS 133). SFAS 133 establishes accounting and reporting standards requiring that all derivative instruments, other than those that meet the normal purchases and sales exception, be recorded on the balance sheet as either an asset or liability measured at fair value (which is generally based on information obtained from independent parties). SFAS 133 also requires that changes in fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Hedge accounting treatment allows unrealized gains and losses on cash flow hedges to be deferred in other comprehensive income. Realized gains and losses from the Company s oil and gas cash flow hedges, including terminated contracts, are generally recognized in oil and gas production revenues when the forecasted transaction occurs. Gains and losses from the change in fair value of derivative instruments that do not qualify for hedge accounting are reported in current period income. If at any time the likelihood of occurrence of a hedged forecasted transaction ceases to be probable, hedge accounting under SFAS 133 will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings. Amounts recorded in other comprehensive income prior to the change in the likelihood of occurrence of the forecasted transaction will remain in other comprehensive income until such time as the forecasted transaction impacts earnings. If it becomes probable that the original forecasted production will not occur, then the derivative gain or loss would be reclassified from accumulated other comprehensive income into earnings immediately. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time, and any ineffectiveness is immediately reported in the consolidated statement of operations.

Concentration of credit risk

Financial instruments that potentially subject the Company to concentrations of credit risk consist principally of temporary cash investments, trade accounts receivable, and derivative instruments. The Company places its excess cash investments with high quality financial institutions. The Company extends credit, primarily in the form of uncollateralized oil and gas sales, to various companies in the oil and gas industry, which results in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions within the oil and gas industry and may accordingly impact the Company s overall credit risk. However, management believes that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of the companies to which the Company extends credit. The Company has not experienced any losses from its receivables or cash investments, and does not believe that it has any significant concentration of credit risk.

The Company sells a portion of its oil and gas to end users through various marketing companies. For the years ended December 31, 2008, 2007 and 2006, crude oil sales to Sunoco Partners Marketing & Terminals, L.P. accounted for 96%, 93% and 96%, respectively, of its oil and gas revenues. The percentage is calculated on oil and gas revenues before any effects of price risk management activities.

New accounting pronouncements

In May 2008, the Financial Accounting Standards Board (FASB) issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (SFAS 162), which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America (the GAAP hierarchy). This statement is effective 60 days following the Securities and Exchange Commission s (the SEC) approval of the Public Company Accounting Oversight Board amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles. The adoption of SFAS 162 is not expected to have a material effect on the Company s financial statements or related disclosures.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities-an amendment of FASB Statement No. 133 (SFAS 161). This statement requires enhanced disclosures about derivative and hedging activities. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The adoption of SFAS No. 161 is not expected to have a material effect on the Company s financial statements or related disclosures.

During December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements-an amendment of ARB No. 51 (SFAS 160), which causes noncontrolling interests in subsidiaries to be included in the equity section of the balance sheet. SFAS 160 is effective for periods beginning on or after December 15, 2008. This standard does not presently affect the Company s financial statements.

During December 2007, the FASB issued SFAS No. 141(R), Business Combinations (SFAS 141(R)), which establishes new accounting and disclosure requirements for recognition and measurement of identifiable assets, liabilities and goodwill acquired and requires that the fair value estimates of contingencies acquired or assumed be considered as part of the original purchase price allocation. SFAS 141(R) is effective for periods beginning on or after December 15, 2008. This standard does not presently affect the Company s financial statements.

Note 3 Long-term Debt

Long-term debt at December 31, 2008 and 2007 consisted of the following (in thousands):

	2008	2007
Senior term loan	$ 52,807	$ 50,000
Revolving loan	23,540	4,500
	76,347	54,500
Less: unamortized discount	(1,801)	(2,257)
	74,546	52,243
Less: current portion	(74,546)	
	$	$ 52,243

In 2007, the Company entered into a Credit Agreement with various lenders and Wells Fargo Foothill, LLC, as agent (the Pre-Petition Credit Facility). The Pre-Petition Credit Facility provides for a $50 million term loan facility and a $50 million revolving credit facility, with an initial borrowing base of $25 million available under the revolving credit facility. The Pre-Petition Credit Facility matures in December 2012, with principal payments scheduled to commence in April 2010 based on 50% of the Company s cash flow, net of capital expenditures. The Pre-Petition Credit Facility has restrictions on the operations of the Company s business, including restrictions on payment of dividends. Borrowings under the term loan facility carry prepayment penalties ranging from 1.00% to 2.00% in the first three years of the Pre-Petition Credit Facility. Borrowings under the revolving credit facility may be repaid at any time without penalty. The Pre-Petition Credit Facility is secured by liens and security interests on substantially all of the assets of the Company, including 100% of the Company s oil and gas reserves. In connection with the Pre-Petition Credit Facility, Foothills issued to the lender under the term loan facility a ten-year warrant to purchase 2,580,159 shares of Foothills common stock at an exercise price of $0.01 per share. The fair value of the warrant was recorded as debt issue discount, and is being amortized using the interest method.

The Company used a portion of the proceeds of the Pre-Petition Credit Facility to retire amounts outstanding under a secured promissory note in the principal amount of $42,500,000 under a previous credit agreement (the Mezzanine Facility).

The Pre-Petition Credit Facility contains financial covenants pertaining to asset coverage, interest coverage and leverage ratios. A violation of any of these financial covenants, unless waived by the Company s lenders, constitutes an event of default under the Pre-Petition Credit Facility, giving the Company s lenders the right to terminate their obligations to make additional loans under the Pre-Petition Credit Facility, demand immediate payment in full of all amounts outstanding, foreclose on collateral and exercise other rights and remedies granted under the Pre-Petition Credit Facility and as may be available pursuant to applicable law. As of March 31, 2008, the Company was not in compliance with the leverage ratio covenant. The Company, the lenders and the agent entered into a First Amendment to Credit Agreement and a Limited Waiver and Second Amendment to Credit Agreement, pursuant to which the lenders waived non-compliance with the leverage ratio covenant and the interest rate on the term loan facility was modified to provide that it will not be less than 10.50% in the event that the London Interbank Offered Rate (LIBOR) is less than 4.00%.

As of June 30, 2008, the Company was not in compliance with the asset coverage and leverage ratio covenants of the Pre-Petition Credit Facility and is in default under the Pre-Petition Credit Facility. Until such time as no event of default exists, the interest rate under the Pre-Petition Credit Facility increased by an additional 2% in excess of the otherwise applicable interest rate on amounts outstanding under the Pre-Petition Credit Facility.

The lenders and the agent agreed to forbear until September 15, 2008, which was subsequently extended to December 31, 2008, from exercising their rights and remedies under the Pre-Petition Credit Facility arising as a result of the financial covenants defaults. The Company considered and actively pursued various strategic alternatives, which included a sale of a portion of the Company s assets, a merger or other business combination, or the issuance of equity or other securities, in connection with the repayment of all or a portion of the Company s obligations under the Pre-Petition Credit Facility.

On February 11, 2009, Foothills and each of its subsidiaries filed voluntary petitions for reorganization relief under Chapter 11 of the Bankruptcy Code. The filing of the Chapter 11 Cases triggered an event of default under the Pre-Petition Credit Facility. As a result of such event of default, all obligations under the Pre-Petition Credit Facility became immediately due and payable. Under the Bankruptcy Code, actions to collect pre-petition indebtedness are stayed and other contractual obligations against the Debtors generally may not be enforced during the pendency of the Chapter 11 proceedings. Absent an order from the Bankruptcy Court, substantially all pre-petition liabilities are subject to settlement under a plan of reorganization to be approved by the Bankruptcy Court. Consequently, the Company has classified the indebtedness under the Pre-Petition Credit Facility within current liabilities in its consolidated balance sheet as of December 31, 2008.

Note 4 Stockholders Equity

Registration rights payments

The purchasers of units consisting of shares of common stock and warrants issued by Foothills in private placement financings in 2006 have registration rights, pursuant to which the Company agreed to register for resale the shares of common stock and the shares of common stock issuable upon exercise of the warrants. In the event that the registration statements are not declared effective by the SEC by specified dates, the Company is required to pay liquidated damages to the purchasers.

The purchasers of 17,142,857 units issued in April 2006 are entitled to liquidated damages in the amount of 1% per month of the purchase price for each unit, payable each month that the registration statement is not declared effective following the mandatory effective date (January 28, 2007). The total amount recorded at December 31, 2008 for these liquidated damages was $322,000. Amounts payable as liquidated damages cease when the shares can be sold under Rule 144 of the Securities Act of 1933, as amended. The Company has determined that liquidated damages ceased on April 6, 2007 as to a minimum of 16,192,613 units, and that liquidated damages ceased on July 6, 2007 as to the remaining units.

The purchasers of an aggregate of 10,093,804 units issued in September 2006 are entitled to liquidated damages in the amount of 1% per month of the purchase price for each unit, payable each month that the registration statement is not declared effective following the applicable mandatory effective dates (March 7, 2007 for 10,000,000 units and March 28, 2007 for the remaining 93,804 units). The total amount recorded at December 31, 2008 for these liquidated damages was $2,271,000. The investors in the September 2006 private placement financing have the right to take the liquidated damages either in cash or in shares of Foothills common stock, at their election. If the Company fails to pay the cash payment to an investor entitled thereto by the due date, the Company will pay interest thereon at a rate of 12% per annum (or such lesser maximum amount that is permitted to be paid by applicable law) to such investor, accruing daily from the date such liquidated damages are due until such amounts, plus all such interest thereon, are paid in full. The total amount of liquidated damages will not exceed 10% of the purchase price for the units or $2,271,000.

In October 2006, the Company filed the required registration statement, which became effective in June 2008. As a result, the Company had incurred the obligation to pay a total of approximately $2,593,000 in liquidated damages as of December 31, 2008, which amount has been recorded as liquidated damages expense in the consolidated statement of operations.

Warrants

In connection with the Pre-Petition Credit Facility, the Mezzanine Facility, and private placement financings, Foothills issued warrants to purchase shares of its common stock. Warrants outstanding as of December 31, 2008, consisted of the following:

Number of Shares Subject to Warrants	Expiration Date	Exercise Price
2,580,159	December 2017	$0.01
12,077,380	April 2011	$1.00
473,233	September 2011	$2.25
8,046,919	September 2011	$2.75

Note 5 Stock and Other Compensation Plans

Foothills 2007 Equity Incentive Plan (the 2007 Plan) enables the Company to provide equity-based incentives through grants or awards to present and future employees, directors, consultants and other third party service providers. Foothills Board of Directors reserved a total of 5,000,000 shares of Foothills common stock for issuance under the 2007 Plan. The compensation committee of the Board (or the Board in the absence of such a committee), administers the 2007 Plan. The 2007 Plan authorizes the grant to participants of nonqualified stock options, incentive stock options, restricted stock awards, restricted stock units, performance grants intended to comply with Section 162(m) of the Internal Revenue Code, as amended, and stock appreciation rights. Generally, options are granted at prices equal to the fair value of the stock at the date of grant, expire not later than 10 years from the date of grant, and vest ratably over a three-year period following the date of grant.

During 2007, the Company determined that its 2006 Equity Incentive Plan (the 2006 Plan) did not meet certain qualifications required under state laws. As a result, the Company now considers all options granted prior to the adoption of the 2007 Plan to have been granted outside of the scope of the 2006 Plan. Although the Foothills Board of Directors reserved a total of 2,000,000 shares of Foothills common stock for issuance under the 2006 Plan, the Company does not intend to make any equity-based incentive grants or awards under the 2006 Plan.

The estimated fair value of the options granted during 2008, 2007 and 2006 was calculated using a Black Scholes Merton option pricing model (Black Scholes). The following schedule reflects the various assumptions included in this model as it relates to the valuation of options:

	2008	2007	2006
Risk free interest rate	2.5%	4.6 5.2%	4.4 5.0%
Expected volatility	95%	85 116%	79 138%
Weighted-average volatility	95%	102%	88%
Dividend yield	0%	0%	0%
Expected years until exercise	3.0	0.5 3.0	0.5 3.0

The Black Scholes model incorporates assumptions to value stock-based awards. The risk-free rate of interest for periods within the expected term of the option was based on a zero-coupon U.S. government instrument over the expected term of the equity instrument. Because Foothills common stock has limited trading history, expected volatility was based on the historical volatility of a representative stock with characteristics similar to the Company. The Company has no historical experience upon which to base estimates of employee option exercise timing (expected term) within the valuation model, and utilized estimates for the expected term based on criteria required by SFAS 123R.

Option activity as of December 31, 2008, 2007 and 2006 and changes during the years then ended were as follows:

	2008		2007		2006	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding, beginning of year	1,880,000	$ 1.52	1,790,000	$ 1.53		$
Granted	597,500	0.14	95,000	1.19	1,790,000	1.53
Exercised						
Forfeited	(188,125)	0.62	(5,000)	1.42		
Outstanding, end of year	2,289,375	$ 1.23	1,880,000	$ 1.52	1,790,000	$ 1.53
Exercisable, end of year	1,078,750	$ 1.43	1,078,750	$ 1.62	560,000	$ 1.82

Stock-based compensation relating to stock options for the years ended December 31, 2008, 2007 and 2006 totaling $410,000, $458,000 and $388,000, respectively, has been recognized as a component of general and administrative expenses in the accompanying consolidated financial statements. The weighted-average grant-date fair values of options granted during the years ended December 31, 2008, 2007 and 2006 were $0.08, $0.53 and $0.80, respectively. As of December 31, 2008, $275,000 of total unrecognized compensation cost related to stock options is expected to be recognized over a weighted-average period of approximately 2.7 years. No stock options were exercised during the years ended December 31, 2008, 2007 or 2006. The total options outstanding as of December 31, 2008, had a weighted-average remaining term of 7.9 years and an aggregate intrinsic value of zero. The options exercisable as of December 31, 2008, had a weighted-average remaining term of 7.7 years and an aggregate intrinsic value of zero. Aggregate intrinsic value represents the total pre-tax intrinsic value (the difference between the closing stock price on the last trading day of each year and the exercise price, multiplied by the number of in-the-money options) that would have been received by the option holders had all option holders exercised their options on the last trading day of each year. The amount of aggregate intrinsic value will change based on the fair market value of the Company s stock.

The following table summarizes information about stock options outstanding at December 31, 2008:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Term In Years	Weighted Average Exercise Price	Number Exercisable	Weighted Average Remaining Contractual Term In Years	Weighted Average Exercise Price
$ 0.14	483,125	9.6	$ 0.14	149,375	9.6	$ 0.14
0.70	800,000	7.3	0.70	600,000	7.3	0.70
1.17 1.99	696,250	7.8	1.68	563,750	7.7	1.68
2.50 3.59	310,000	7.3	3.32	257,500	7.3	3.29
$ 0.14 3.59	2,289,375	7.9	$ 1.23	1,570,625	7.7	$ 1.43

In 2007, the Company awarded an aggregate of 141,176 shares of restricted stock to certain officers under the 2007 Plan, of which 46,209 shares have been withheld and canceled by the Company in lieu of employee tax withholding obligations. The vesting schedule was established to match the vesting schedule of stock options previously granted to those officers. The restricted stock grants are subject to forfeiture, and cannot be sold, transferred or disposed of during the restriction period. The holders of the shares have voting and dividend rights with respect to such shares.

The following is a summary of restricted stock activity for the years ended December 31, 2008 and 2007:

	Shares	
	2008	**2007**
Outstanding, beginning of year	109,772	
Awarded		141,176
Canceled / forfeited	(14,805)	(31,404)
Outstanding, end of year	94,967	109,772
Vested, end of year	59,671	39,183

Stock-based compensation relating to restricted stock awards for the years ended December 31, 2008, and 2007 totaling $40,000 and $69,000, respectively, has been recognized as a component of general and administrative expenses in the accompanying consolidated financial statements. The weighted-average grant-date fair value of restricted stock awarded during the year ended December 31, 2007, was $0.85 per share. As of December 31, 2008, the aggregate values of both restricted stock outstanding and restricted stock vested were $1,000. As of December 31, 2008, $11,000 of total unrecognized compensation cost related to restricted stock awards is expected to be recognized over a weighted-average period of approximately 0.3 years.

As of December 31, 2008, 4,375,699 shares were available for future equity-based incentive grants or awards under the 2007 Plan.

During 2007, the Company implemented a 401(k) Savings Plan which covers all its employees. The Company matches a percentage of the employees contributions to the plan in an amount equal to 100% of the first 3% and 50% of the next 2% of each participant s compensation. The Company s matching contributions to the plan were approximately $44,000 and $15,000 for the years ended December 31, 2008 and 2007, respectively.

Note 6 Income Taxes

A reconciliation of the income tax provision (benefit) at the U.S. statutory rate (34%) to the Company s actual income tax provision (benefit) for the years ended December 31, 2008, 2007 and 2006 is shown below (in thousands):

	2008	**2007**	**2006**
Income tax provision (benefit) at 34%	$ (20,147)	$ (8,850)	$ (1,280)
Changes in prior year estimate	(232)	(504)	
Non-deductible expenses	158	185	139
Change in valuation allowance	20,221	9,169	1,141
Income tax provision (benefit)	$	$	$

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Significant components of the Company s net deferred income tax assets and liabilities as of December 31, 2008 and 2007 were as follows (in thousands):

	2008	2007
Deferred tax assets:		
Net operating loss carryforwards	$ 20,869	$ 14,616
Stock-based compensation	464	311
Differences between book and tax bases of property, plant and equipment	9,163	
	30,496	14,927
Deferred tax liabilities:		
Differences between book and tax bases of property, plant and equipment		4,652
Net deferred tax asset before valuation allowance	30,496	10,275
Valuation allowance	(30,496)	(10,275)
Net deferred tax asset (liability)	$	$

A full valuation allowance was established for net deferred tax assets due to the uncertainty of realizing these deferred tax assets, based on conditions existing as of December 31, 2008.

As of December 31, 2008, the Company had available, for U.S. federal tax purposes, net operating loss carryforwards of approximately $61,380,000 expiring in 2020 through 2028.

Potential implications of Chapter 11 Cases

If the Company s debt is reduced or restructured as a result of the Chapter 11 Cases, the Company may realize cancellation of indebtedness income. However, cancellation of indebtedness income is excluded from gross income if the discharge occurs in a Chapter 11 case, and as a result, the Company will not be subject to federal income tax with respect to such cancellation of indebtedness income. In exchange for the exclusion from gross income for the cancellation of indebtedness income, Section 108(b) of the Internal Revenue Code requires that the amount excluded from gross income be applied to reduce certain specified tax attributes of the Company, such as net operating losses and the tax basis of Company assets. Any such reduction could result in increased future tax liabilities for the Company. Additionally, the utilization of net operating losses may be limited pursuant to Section 382 of the Internal Revenue Code.

Note 7 Derivative Instruments and Price Risk Management Activities

The Company has entered into derivative contracts to manage its exposure to commodity price risk. As of December 31, 2008, these derivative contracts, which are placed with a major financial institution that the Company believes is a minimal credit risk, consisted only of swaps. The oil prices upon which the commodity derivative contracts are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company for its oil production. Swaps are designed to fix the price of anticipated sales of future production. The Company entered into the contracts at the time it acquired certain operated oil and gas property interests as a means to reduce the future price volatility on its sales of oil production, as well as to achieve a more predictable cash flow from its oil and gas properties. The Company has designated its price hedging instruments as cash flow hedges in accordance with SFAS 133. The Company recognizes gains or losses on settlement of its hedging instruments in oil and gas revenues, and changes in their fair value as a component of other comprehensive income, net of deferred taxes. In connection with realized settlements of its price hedging contracts, the Company recognized pre-tax losses of $4,351,000 and $201,000 for the years ended December 31, 2008 and 2007, respectively, and a pre-tax gain of $344,000 for the year ended December 31, 2006. Accumulated other comprehensive income (loss) included an unrealized gain of $2,378,000 as of December 31, 2008, and an unrealized loss of $6,799,000 as of December 31, 2007 on the Company s cash flow hedges. As of December 31, 2008, the Company anticipated that $2,016,000 of unrealized gains, net of deferred taxes of zero, will be reclassified into earnings within the next 12 months. Irrespective of the unrealized gains or losses reflected in other comprehensive income, the ultimate impact to net income over the life of the hedges will reflect the actual settlement values. No cash flow hedges were determined to be ineffective during 2008. Further details relating to the Company s hedging activities are as follows:

Hedging contracts held as of December 31, 2008:

Contract Period and Type	Total Volume	NYMEX Swap Price	Fair Value (in thousands)
Crude oil contracts (barrels)			
Swap contracts:			
January 2009 December 2009	135,041	$ 69.39	$ 2,016
January 2010 September 2010	74,206	68.00	362
		Total	$ 2,378

Note 8 Fair Value Measurements

Effective January 1, 2008, the Company adopted SFAS No. 157, Fair Value Measurements (SFAS 157) for all financial assets and liabilities measured at fair value on a recurring basis. The statement establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The statement establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The statement establishes a hierarchy for grouping these assets and liabilities, based on the significance level of the following inputs:

Level 1 Quoted prices in active markets for identical assets or liabilities

Level 2 Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable

Level 3 Significant inputs to the valuation model are unobservable.

The following is a listing of the Company s assets required to be measured at fair value on a recurring basis and where they are classified within the hierarchy as of December 31, 2008 (in thousands):

	Level 1	Level 2	Level 3
Fair value of derivative financial instruments	$	$2,378	$

A financial asset or liability is categorized within the hierarchy based upon the lowest level of input that is significant to the fair value measurement. The Company s oil swaps are valued using the counterparty s mark-to-market statements and are classified within Level 2 of the valuation hierarchy.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, which permits all entities to choose, at specified election dates, to measure eligible items at fair value. The Company adopted this statement as of January 1, 2008, but did not elect fair value as an alternative, as provided in the statement.

Note 9 Related Party Transactions

In 2006, the Company entered into an agreement (the Business Development Agreement) with Moyes & Co., Inc. (Moyes & Co.) to identify potential acquisition, development, exploitation and exploration opportunities that fit with its strategy. Moyes & Co. screened opportunities and performed detailed evaluation of those opportunities that the Company decided to pursue, and assisted with due diligence and negotiations with respect to such opportunities. The Business Development Agreement was terminated by the Company effective November 30, 2008. Christopher P. Moyes was the beneficial owner of 2.6% of Foothills common stock as of December 31, 2008, and is a member of the Company s Board of Directors. Mr. Moyes is a major shareholder and the President of Moyes & Co. Because Moyes & Co. was being compensated for identifying opportunities and assisting the Company in pursuing those opportunities, the interests of Moyes & Co. were not the same as the Company s interests. Management was responsible for evaluating any opportunities presented to the Company by Moyes & Co. to determine if those opportunities were consistent with its business strategy. Mr. Moyes has foregone his compensation as a director, pursuant to the terms of the Business Development Agreement. Under the agreement, the Company paid Moyes & Co. a monthly retainer of $17,500 and additional fees for services requested that exceed those covered by the retainer, and reimbursed normal business travel and other expenses, in exchange for Moyes & Co. s services. For the years ended December 31, 2008, 2007 and 2006, billings to the Company by Moyes & Co. amounted to approximately $208,000, $340,000 and $331,000, respectively, for the monthly retainer and additional services, and $18,000, $42,000 and $54,000, respectively, for business travel and other expenses. At December 31, 2008, approximately $19,000 of unpaid invoices from Moyes & Co. was included in accounts payable and accrued liabilities in the accompanying consolidated balance sheet, which invoices were subsequently paid.

Pursuant to the Company s business plan with respect to the Anadarko Basin in southwest Oklahoma, it acquired non-exclusive rights to a 3D seismic survey in Roger Mills County, Oklahoma as a result of the merger of TeTra Ex, Inc. (TeTra), a company owned by John L. Moran, Foothills President, into a wholly owned subsidiary of Foothills in October 2008. TeTra reprocessed the 3D survey, completed geological and geophysical interpretations of the survey data, and identified drillable prospects. The Company has acquired oil and gas leases over those prospects, and plans to negotiate joint ventures with other companies. Mr. Moran and John A. Brock, a director of Foothills, are or will be entitled to receive an assignment of an overriding royalty interest on any oil and gas leases acquired by the Company over such prospects, with the amount of the overriding royalty interest determined in accordance with a sliding scale formula based on the lessor royalty interest in such leases.

Note 10 Commitments and Contingencies

Rental commitments

The Company has operating lease commitments expiring at various dates, principally for office space. Future minimum payments for noncancelable operating leases with initial or remaining terms in excess of one year as of December 31, 2008, were as follows (in thousands):

2009	$ 129
2010	124
2011	42
Total	$ 295

Rental expense for operating leases, including leases with terms of less than one year, was $175,000 for the year ended December 31, 2008.

Note 11 Legal Proceedings

From time to time, the Company may become a party to litigation or other legal proceedings that, in the opinion of management are part of the ordinary course of our business. Other than the Chapter 11 bankruptcy proceedings, which are described below, no legal proceedings or claims are pending against or involve the Company

that, in the opinion of management, could reasonably be expected to have a material adverse effect on its business, prospects, financial condition or results of operations. In general, the Company has agreed to indemnify its officers and directors against any and all losses, claims, damages, expenses (including reasonable costs, disbursements and counsel fees) and liabilities (including amounts paid or incurred in satisfaction of settlements, judgments, fines and penalties) incurred by them in any legal proceedings absent a showing of such persons gross negligence or malfeasance.

On February 11, 2009 (the Petition Date), the Debtors filed voluntary petitions for reorganization relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. The Chapter 11 Cases are being jointly administered under the caption *Foothills Texas, Inc., et al., Debtors, Chapter 11 Case No. 09-10452 (CSS)*.

The Debtors continue to operate their businesses as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with applicable provisions of the Bankruptcy Code and the orders of the Bankruptcy Court. As debtors-in-possession, the Debtors are authorized to continue to operate as ongoing businesses, and may pay all debts and honor all obligations arising in the ordinary course of their businesses after the Petition Date. However, the Debtors may not pay creditors on account of obligations arising before the Petition Date or engage in transactions outside the ordinary course of business without approval of the Bankruptcy Court, after notice and an opportunity for a hearing.

Under the Bankruptcy Code, actions to collect pre-petition indebtedness are stayed. Other pre-petition contractual obligations against the Debtors generally may not be enforced. Absent an order of the Bankruptcy Court providing otherwise, substantially all pre-petition liabilities are subject to settlement under a plan of reorganization to be voted upon by creditors and other stakeholders, and approved by the Bankruptcy Court.

Under the priority scheme established by the Bankruptcy Code, certain post-petition and secured or priority pre-petition liabilities need to be satisfied before general unsecured creditors and holders of the Company s equity are entitled to receive any distribution. No assurance can be given as to what values, if any, will be ascribed in the bankruptcy proceedings to the claims and interests of each of these constituencies. Additionally, no assurance can be given as to whether, when or in what form unsecured creditors and holders of the Company s equity may receive a distribution on such claims or interests.

Under the Bankruptcy Code, the Debtors may assume, assume and assign, or reject certain executory contracts and unexpired leases, including, without limitation, leases of real property and equipment, subject to the approval of the Bankruptcy Court and certain other conditions. As of the date of the filing of the Chapter 11 Cases, no party, subject to certain exceptions, may take any action, also subject to certain exceptions, to recover on pre-petition claims against the Debtors.

Note 12 Subsequent Events

In connection with the filing of the Chapter 11 Cases, the Company received debtor-in-possession financing pursuant to a credit agreement (the DIP Credit Agreement) with one of the lenders under the Pre-Petition Credit Facility. The DIP Credit Agreement provides for loans up to an aggregate of $2,500,000, and matures in May 2009. The proceeds of these loans will be used for working capital purposes, including the payment of fees, costs, and expenses incurred in connection with the DIP Credit Agreement and for expenditures consistent with a budget agreed upon by the Company and the lender pursuant to the DIP Credit Agreement.

On April 30, 2009, Foothills Board of Directors voted to voluntarily deregister Foothills common stock under the Securities Exchange Act of 1934 (the Exchange Act) and become a non-reporting company. On or about May 11, 2009, the Company intends to file with the SEC a Form 15, Notice of Termination of Registration and Suspension of Duty to File, to terminate its reporting obligations under the Exchange Act. Once the Company files the Form 15, its obligation to file reports and other information under the Exchange Act, such as Forms 10-K, 10-Q and 8-K will be suspended. The deregistration of the Company s common stock under the Exchange Act will become effective 90 days after the date on which the Form 15 is filed. The Company is eligible to deregister under the Exchange Act because its common stock is held of record by fewer than 300 persons.

SUPPLEMENTAL OIL AND GAS INFORMATION

(unaudited)

The following tables set forth (in thousands) information about the Company s oil and gas producing activities pursuant to the requirements of SFAS No. 69, Disclosures About Oil and Gas Producing Activities. All of the Company s oil and gas producing activities are within the United States.

Capitalized Costs

	2008	2007
Proved properties	$ 90,516	$ 75,215
Unproved properties	898	760
	91,414	75,975
Accumulated depreciation, depletion and amortization	(60,164)	(3,389)
Net capitalized costs	$ 31,250	$ 72,586

The Company s investment in oil and gas properties as of December 31, 2008, included $898,000 in unproved properties which have been excluded from amortization. Such costs were incurred in 2008, 2007 and 2006, and will be evaluated in future periods based on management s assessment of exploration activities, expiration dates of leases, changes in economic conditions and other factors.

Costs Incurred

	2008	2007	2006
Property acquisition:			
Proved properties	$	$	$ 62,939
Unproved properties	390	537	195
Exploration	10,744	1,936	5,818
Development	4,180	8,218	1,448
Total costs incurred	$ 15,314	$ 10,691	$ 70,400

For the years ended December 31, 2008, 2007 and 2006, depreciation, depletion and amortization of the capitalized costs of oil and gas properties was $29.52, $12.59 and $10.33, respectively, per barrel.

Oil and Gas Reserve Quantities

Proved reserves represent estimated quantities of crude oil and natural gas which geological and engineering data demonstrate to be reasonably recoverable in the future from known reservoirs under existing economic and operating conditions. Proved developed reserves can be expected to be recovered through existing wells, with existing equipment and operating methods.

Estimates of proved and proved developed oil and gas reserves are subject to numerous uncertainties inherent in the process of developing the estimates, including the estimation of the reserve quantities and estimated future rates of production and timing of development expenditures. The accuracy of any reserve estimate is a function of the quantity and quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimates. Additionally, the estimated volumes to be commercially recoverable may fluctuate with changes in prices of oil and natural gas.

Estimates of the Company s proved reserves and related valuations, as shown in the following tables, were developed pursuant to SFAS No. 69. The amounts for 2006 have been restated to correct errors identified during 2007 in the estimates of reserve quantities attributable to extensions and discoveries for the Company s California

gas properties and production costs for the Company s Texas oil and gas properties. These corrections did not have a significant effect on the accompanying consolidated financial statements. Crude oil is stated in thousands of barrels. Natural gas is stated in millions of cubic feet.

	2008		2007		2006	
	Oil	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**
Proved developed and undeveloped reserves, beginning of year	4,174	21,803	4,431	21,916		
Extensions and discoveries [1]						21,500[1]
Purchase of reserves in-place [2]					4,501	446
Revisions of previous estimates [3]	(1,187)	(20,947)	(72)	22		
Production	(183)	(79)	(185)	(135)	(70)	(30)
Proved developed and undeveloped reserves, end of year [3]	2,804	777	4,174	21,803	4,431	21,916
Proved developed reserves, end of year [3]	2,708	777	3,884	2,437	4,030	2,190

The following tables present (in thousands) the standardized measure of discounted future net cash flows relating to proved oil and gas reserves as of December 31, 2008, 2007 and 2006, and the changes in the standardized measure of discounted future net cash flows for the years then ended. Future cash inflows and costs were computed using prices and costs in effect at the end of the year, without escalation. Future income taxes were computed by applying the appropriate statutory income tax rate to the pretax future net cash flows, reduced by future tax deductions and net operating loss carryforwards.

1 During 2006, the Company drilled two successful wells in the Eel River Basin in California. The estimate of proved reserves attributable to these discoveries was approximately 21.5 billion cubic feet of natural gas.

2 In 2006, the Company acquired producing properties in the

Texas Gulf Coast area. The estimated proved reserves acquired totaled approximately 4.5 million barrels of crude oil and 446 million cubic feet of natural gas.

3 During 2008, the Company completed the drilling of two wells in the Eel River Basin in California. After perforating the indicated gas-bearing zones in both wells, the Company did not recover natural gas from either well. The Company believed this result was inconsistent with the mud log shows, electric log interpretations, and the offsetting well information. The Company s conclusion was that polymer fluids used during drilling operations most likely damaged the reservoirs near the wellbores. The Company

subsequently attempted to fracture the formations beyond the damaged zones in the wells. Following these operations, the Company was unable to produce natural gas in commercial quantities from either well, and revised its estimates of reserves as of December 31, 2008 by eliminating all proved developed and undeveloped reserves attributable to these formations.

Standardized Measure of Discounted Future Net Cash Flows

	2008	2007	2006
Future cash inflows	$ 127,305	$ 537,791	$ 395,868
Future costs			
Production	71,341	139,969	116,104
Development	5,250	27,230	20,783
Future net cash flows before income taxes	50,714	370,592	258,981
Future income taxes		91,859	71,393
Future net cash flows	50,714	278,733	187,588
10% discount factor	25,107	142,605	88,661
Standardized measure of discounted future net cash flows	$ 25,607	$ 136,128	$ 98,927

Changes in Standardized Measure of Discounted Future Net Cash Flows

	2008	2007	2006
Standardized measure, beginning of year	$ 136,128	$ 98,927	$
Increases (decreases) -			
Sales, net of production costs	(13,792)	(10,464)	(2,914)
Net change in sales prices, net of production costs	(113,748)	60,163	
Extensions and discoveries			40,341
Changes in estimated future development costs	17,911	(4,618)	
Development costs incurred during the year that reduced future development costs	905	2,092	
Revisions of quantity estimates	(39,734)	(22,543)	
Accretion of discount	15,633	11,805	
Net change in income taxes	20,206	(1,076)	(19,130)
Purchase of reserves in-place			80,630
Changes in production rates (timing) and other	2,098	1,842	
Standardized measure, end of year	$ 25,607	$ 136,128	$ 98,927

The following table shows the average prices used in determining the standardized measure, and reflect adjustments for geographical, quality and transportation differentials. Oil prices are per barrel and natural gas prices are per thousand cubic feet.

	2008		2007		2006	
	Oil	Gas	Oil	Gas	Oil	Gas
California	$	$5.54	$	$6.54	$	$6.08
Texas	$43.87	$5.49	$94.46	$7.67	$59.21	$6.77

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

None.

Item 9A. Controls and Procedures.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of the end of the period covered by this report, we have carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission s rules and forms.

Management s Annual Report on Internal Control Over Financial Reporting.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial reporting and the preparation of financial statements for external purposes, in accordance with generally accepted accounting principals. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management, including our president, conducted an evaluation of the effectiveness of internal control over financial reporting using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control Integrated Framework. Based on its evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2008.

This annual report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting. Management s report was not subject to attestation by our registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit us to provide only management s report in this annual report.

Changes in Internal Control Over Financial Reporting

There was no significant change in our internal control over financial reporting that occurred during the fourth quarter of fiscal 2008 that has materially affected, or is reasonably likely to affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

PART III.

Item 10. Directors, Executive Officers and Corporate Governance.

Directors and Executive Officers

The following tables set forth certain information with respect to our directors and executive officers as of March 31, 2009. The following persons serve as our directors:

Directors	Age	Present Position
Dennis B. Tower	62	Director, Chairman of the Board and Chief Executive Officer
John L. Moran	63	Director and President
John A. Brock	78	Director
Ralph J. Goehring	52	Director
Frank P. Knuettel	67	Director
David A. Melman	66	Director
Christopher P. Moyes	62	Director

The following persons serve as our executive officers:

Executive Officers	Age	Present Position
Dennis B. Tower	62	Chief Executive Officer, Chairman of the Board and Director
John L. Moran	63	President and Director
W. Kirk Bosché	58	Chief Financial Officer, Treasurer and Secretary
James H. Drennan	63	Vice President, Land and Legal
Michael L. Moustakis	51	Vice President, Engineering

Our executive officers are appointed by and serve at the discretion of the Board. There are no family relationships between any director and any executive officer.

Dennis B. Tower*, Chairman of the Board, Chief Executive Officer and Director*. Before joining Foothills as its Chief Executive Officer in 2006, Mr. Tower had extensive involvement in all phases of new venture exploration, appraisal, project evaluation and development, asset acquisition and disposal, strategic goals setting and human resource evaluation. During 2005, Mr. Tower, together with Messrs. Moran and Bosché, evaluated opportunities that would be appropriate for launching a new oil and gas exploration and development company, which ultimately led to the formation of Foothills California, Inc. (Foothills California) at the end of 2005, which became a wholly owned subsidiary of the Company in April 2006. From 2000 through 2004, Mr. Tower served as President and Chief Executive Officer at First International Oil Corporation, a privately held independent oil company with extensive holdings in Kazakhstan, where he led the company to a successful sale with a major Chinese oil company. Previously, Mr. Tower held several Vice President, Manager, Director and Geologist positions at Atlantic Richfield Company (ARCO), where he was responsible for the company s Mozambique drilling operations, managed the company s exploration licenses in Myanmar and the Philippines, coordinated exploration efforts in other Asian countries and evaluated field redevelopment and asset acquisition opportunities. Mr. Tower led ARCO s North Sea exploration activities for a nine-year period during which ARCO made numerous new oil and natural gas discoveries in the United Kingdom, Norway and the Netherlands. During the course of his career, Mr. Tower has been directly involved in the discovery of 35 oil and gas fields in 11 different countries. Mr. Tower holds both Bachelor s and Master s degrees in Geology from Oregon State University.

John L. Moran*, President and Director*. Prior to joining Foothills in 2006, Mr. Moran, together with Messrs. Tower and Bosché, evaluated opportunities during 2005 that would be appropriate for launching a new oil and gas exploration and development company, which ultimately led to the formation of Foothills California at the end of 2005. In 2000, Mr. Moran formed and later served as President and Exploration Manager of Carneros Energy, Inc., a private oil and gas exploration company with exploration and acquisition emphasis in the San Joaquin and Sacramento Basins of California, where he was responsible for obtaining $75 million in equity funding. From 1997 through 1998, Mr. Moran founded and acted as President of Integrated Petroleum Exploration (IPX) which merged with and into Prime Natural Resources (Prime) in 1998, where he served as Vice President of Exploration. Prior to his time at IPX and Prime, Mr. Moran served as both Vice President Exploration/Chief Geologist and Exploration Manager/MidContinent Region for Apache Corporation. In 1995 Mr. Moran left Apache to found TeTra Exploration, Inc., an oil and gas exploration and development company using 3D seismic to explore for oil and gas in the Anadarko Basin in Oklahoma. He was responsible for the acquisition of the right to use 13,000 miles of 2D seismic for exploration purposes and was instrumental in using this to develop a 75 square-mile 3D seismic project that was later sold to a major oil and gas company. Mr. Moran holds both Bachelor s and Master s degrees in Geology with a major in Stratigraphy and a minor in Petrology from Oregon State University.

W. Kirk Bosché*, Chief Financial Officer, Treasurer and Secretary*. Mr. Bosché joined Foothills in 2006 as its Chief Financial Officer. Mr. Bosché has diversified experience as a financial and accounting executive officer in public and private oil and gas exploration and production organizations. During 2005, Mr. Bosché, together with Messrs. Tower and Moran, evaluated opportunities that would be appropriate for launching a new oil and gas exploration and development company, which ultimately led to the formation of Foothills California at the end of 2005. Mr. Bosché served as Chief Financial Officer of First International Oil Corporation from 1997 through 2004. From 1986 through 1997, Mr. Bosché was Vice President and Treasurer for Garnet Resources Corporation, a publicly traded independent oil and gas exploration and production company with activities in seven foreign countries. He began his career with Price Waterhouse & Co., and has been a Certified Public Accountant since 1975. Mr. Bosché holds a BBA in Accounting from the University of Houston.

James H. Drennan*, Vice President, Land and Legal*. Prior to joining Foothills in 2006, Mr. Drennan was Land Manager at Vaquero Energy Inc. From 2002 through 2005, he served as General Counsel and Land Manager of Carneros Energy, Inc. From 1990 through 2002, Mr. Drennan practiced law with the firms of Jones & Beardsley and Noriega and Bradshaw, where his practice areas included oil and gas, real estate, estate planning, probate, corporate, general business and litigation. From 1978 to 1990, he was Land Manager for Buttes Resources, Depco, Inc., Ferguson & Bosworth, and Bosworth Oil Co. Mr. Drennan started his career in the oil and gas industry in 1974 as land agent with Gulf Oil Corporation. He holds a JD from California Pacific School of Law, and a BA in Economics from San Diego State University.

Michael L. Moustakis*, Vice President, Engineering*. Mr. Moustakis joined Foothills as Vice President, Engineering in 2006. He was Engineering Manager at Rockwell Petroleum, Inc. from 2005 through 2006, and held the same position at OXY Resources California LLC from 2001 through 2005. Mr. Moustakis was Lead Petroleum Engineer with Preussag Energie GmbH from 2000 to 2001, and Director of Reservoir Engineering for Anglo-Albanian Petroleum Ltd. from 1994 to 2000. He began his career with Union Oil of California in 1984, and subsequently served in various engineering positions at several companies, including Shell Western E&P, Northern Digital Inc. and Eastern Petroleum Services Ltd. He holds a Bachelor s degree in Petroleum Engineering from the University of Alaska.

John A. Brock*, Director*. Mr. Brock became a director of Foothills in 2006. Mr. Brock served as Chairman of Brighton Energy, LLC until its sale in October 2006. He is a director of American Trustcorp., Fabtec, Inc. (ReRoof America), Lifeguard America, LLC, Soho Properties, LLC, Medallion Petroleum, Inc. and the AGOS Group, LLC, and is an advisory director of Ward Petroleum, Inc. Mr. Brock is a member of nine petroleum industry associations. During his distinguished career, he has formed exploration departments and instituted and supervised exploration programs for four successful companies. Mr. Brock is a Founder and Director of the Sarkeys Energy Center at the University of Oklahoma, is a Director of the Oklahoma Nature Conservancy and the Sutton Avian Research Center, and is active in numerous other civic and community groups. He has also organized and is currently Chairman of Oklahomans for Lawsuit Reform and co-chairman of Oklahomans for Workers Compensation Reform. Mr. Brock holds a B.S. in Geological Engineering from the University of Oklahoma.

Ralph J. Goehring, *Director*. Mr. Goehring became a director of Foothills in 2008. In January 2009 he joined Bonanza Creek Energy Operating Co., LLC, a privately held oil and gas company with interests in California, Colorado and Arkansas, as Executive Vice President and Chief Financial Officer. Mr. Goehring was a key player in the strategic growth and direction of Berry Petroleum Company for 20 years, including 16 years as Chief Financial Officer, and retired from Berry in mid 2008. As a member of Berry s executive management team, he was involved in setting the strategic direction of the company, determining growth opportunities, including strategies to achieve successful outcomes, negotiating transactions and performing due diligence. As Berry s Chief Financial Officer, he had oversight of all financial functions for the company, including tax, investor relations, and hedging and risk management programs. Mr. Goehring holds a Bachelor of Science in Business Administration from the University of California, Berkeley, and is a Certified Public Accountant.

Frank P. Knuettel*, Director*. Mr. Knuettel became a director of Foothills in 2006. He is an Adjunct Faculty member at The Mason School of Business at the College of William and Mary where he teaches securities analysis and Investment Banking. Prior to retiring in 2000, he was a Managing Director of PaineWebber, Inc., since acquired by UBS Securities, where he specialized in the analysis of energy and energy-related securities, as well as working in investment banking on energy transactions. His career spanned nearly 35 years, during which he was associated with an energy sector fund for 14 years and was in the securities industry for 21 years. Mr. Knuettel is a Chartered Financial Analyst, and a member of the National Association of Petroleum Investment Analysts and the CFA Institute. He holds a Bachelor of Science in Accounting from La Salle University and a Master of Business Administration (Finance) from St. John s University.

David A. Melman*, Director*. Mr. Melman became a director of Foothills in 2006. He currently is President, Chief Executive Officer and a director of British American Natural Gas Corporation, which is engaged in energy exploration in Mozambique, and a director of Swift LNG, LLC and Sunrise Energy Resources, Inc. (OTCBB). He was a director of Omni Energy Services, Inc. (NASDAQ) from 2004 to 2005 and of Beta Oil and Gas, Inc. (NASDAQ) from 2003 to 2004. From 1998 to 2000, he served as the Chief Corporate Officer and a director of Capatsky Oil and Gas Co., a predecessor to Cardinal Resources plc. (AIM), an oil and gas company with interests in the Ukraine. His professional experience includes the practice of law with Burke & Burke (1969-1971) and of accountancy with Coopers & Lybrand (1968-1969). He is a member of the New York State Bar. Mr. Melman holds a degree in Economics and Accounting from Queens College of the City University of New York, a Juris Doctor from Brooklyn Law School and a Master of Law in Taxation from New York University Graduate School of Law.

Christopher P. Moyes*, Director*. Mr. Moyes became a director of Foothills in 2006. He has been active in the international and domestic oil and gas business since 1968. Mr. Moyes is President of Moyes & Co., Inc., a private energy advisory firm headquartered in Dallas, Texas. Moyes & Co., Inc. provides advice on oil and gas exploration, appraisal, project and portfolio evaluation, asset acquisitions and disposals and maintains a proprietary database covering upstream oil and gas. Moyes & Co., Inc. has through 2005 evaluated opportunities for launching a new oil and gas exploration and production company, which led to the formation of Foothills California at the end of 2005. Previously Mr. Moyes was President of Gaffney Cline & Associates (GCA), based in Dallas, Texas. Before coming to Dallas in 1976, Mr. Moyes was based in Singapore and London for GCA, holding various management functions. Mr. Moyes started his career with West Australian Petroleum Pty. Ltd., in Perth Australia. Mr. Moyes holds a Bachelor of Science in Geology from the University of Western Australia and a Master of Science in Geology and Petroleum Engineering from the Royal School of Mines, Imperial College, London.

Meetings and Committees

The Board held seven meetings during fiscal 2008 and acted three times by unanimous written consent. All of the directors attended at least 75% of the meetings of the Board and committees of which they are members.

The Board has an audit and compensation committee, each of which is constituted solely of independent directors. The Board does not have a nominating committee. Until further determination, the full board of directors will undertake the duties of the nominating committee.

Audit Committee

The Audit Committee consists of Messrs. Goehring, Knuettel and Melman, each an independent director. Mr. Goehring qualifies as an audit committee financial expert as that term is defined in Item 407(d)(5) of Regulation S-K. During fiscal 2008, the Audit Committee held four meetings and acted two times by unanimous written consent.

Among other matters, the Audit Committee:

- Discusses with management and the independent registered public accounting firm the quality of our accounting principles and financial reporting;

- Engages and replaces the independent registered public accounting firm as appropriate;

- Evaluates the performance of, independence of and pre-approves all services provided by the independent registered public accounting firm; and

- Oversees our internal controls.

Compensation Committee

The Compensation Committee consists of Messrs. Brock, Goehring and Melman, each an independent director. During fiscal 2008, the Compensation Committee held two meetings and took no action by unanimous written consent.

Among other matters, the Compensation Committee:

- Assists the Board in ensuring that a proper system of long-term and short-term compensation is in place to provide performance-oriented incentives to management, and that compensation plans are appropriate and competitive and properly reflect the objectives and performance of management and the Company;

- Establishes the compensation of all of our executive officers;

- Prepares a report of the Compensation Committee for inclusion in the Company s annual proxy statement; and

- Administers the Company s equity incentive programs, including the 2007 Equity Incentive Plan.

The Compensation Committee is responsible for overseeing the determination, implementation and administration of remuneration, including compensation, benefits and perquisites, of all executive officers and other members of senior management whose remuneration is the responsibility of the Board.

More specifically, the Compensation Committee s responsibilities include: (a) in consultation with senior management, establishing the Company s general compensation philosophy and objectives; (b) reviewing and approving goals and objectives relevant to the compensation of the Chief Executive Officer and President; (c) annually evaluating that performance in light of the goals and objectives established; (d) reviewing and approving all compensation for executive officers, other than our Chief Executive Officer and President; (e) reviewing and approving all employment agreements, severance agreements, change in control provisions and agreement and any special supplemental benefits applicable to the Company s executive officers; (f) reviewing and making recommendations to the Board with respect to incentive compensation and equity-based plans; (g) reviewing and discussing with management the disclosures made in the Compensation Discussion and Analysis prior to the filing of the Company s Annual Report on Form 10-K and proxy statement for the annual meeting of stockholders, and recommending to the Board whether the Compensation Discussion and Analysis should be included in the Annual Report on Form 10-K and proxy statement; (h) preparing an annual compensation committee report for inclusion in the Company s proxy statement for the annual meeting of stockholders in accordance with the applicable rules of the Securities and Exchange Commission; (i) conducting an annual performance evaluation of the Compensation Committee; (j) reviewing and reassessing the adequacy of the Compensation Committee charter on an annual basis and recommending any proposed changes to the Board for approval; and (k) administering the Company s equity-based compensation plans, including the grant of stock options and other equity awards under such plans.

The Compensation Committee has the authority to delegate the responsibilities listed above to subcommittees of the Compensation Committee if it determines such delegation would be in the best interest of the Company.

Compensation Policies

Our executive compensation program is designed to attract and retain executives capable of leading us in pursuit of our business objectives and to motivate them in order to enhance long-term stockholder value. Long-term equity compensation also is used to harmonize the interests of management and stockholders. The main elements of the program are competitive pay and equity incentives. Annual compensation for our executive officers historically consists of three primary elements: base salary, incentive bonuses and stock options.

The Compensation Committee considers a variety of individual and corporate factors in assessing our executive officers and making informed compensation decisions. These factors include each officer s contributions to our business objectives, the compensation paid by comparable companies to employees in similar situations, and, most importantly, our progress towards our long-term business objectives. The factors that are used by the Compensation Committee in evaluating the compensation of the Chief Executive Officer and President are no different from those that are used to evaluate the compensation of other executives.

Director Nominations

All of our directors participate in the consideration of director nominees. However, consistent with applicable NASDAQ listing standards, each director nominee must be selected or recommended for the Board s selection by a majority of the independent directors of our Board. We currently do not have a charter or written policy with regard to the nomination process. In considering candidates for directorship, the Board considers the entirety of each candidate s credentials and does not have any specific minimum qualifications that must be met in order to be recommended as a nominee. The Board does believe, however, that all Board members should have the highest character and integrity, a reputation for working constructively with others, sufficient time to devote to Board matters and no conflict of interest that would interfere with their performance as a director of a public corporation.

Our Board may employ a variety of methods for identifying and evaluating nominees for director, including stockholder recommendations. The Board regularly assesses its size, the need for particular expertise on the Board and whether any vacancies are expected due to retirement or otherwise. If vacancies are anticipated or otherwise arise, the Board will consider various potential candidates for director who may come to the Board s attention through current Board members, professional search firms or consultants, stockholders or other persons. The Board may hire and pay a fee to consultants or search firms to assist in the process of identifying and evaluating candidates. No such consultants or search firms have been used to date and, accordingly, no fees have been paid to consultants or search firms in the past fiscal year. The Board does not evaluate candidates differently based on who made the recommendation for consideration.

The Board will consider for nomination as directors persons recommended by stockholders. Such recommendations must be in writing and delivered to our Secretary at 4540 California Avenue, Suite 550, Bakersfield, California 93309, at least 120 calendar days before the date that our Proxy Statement is released to stockholders in connection with the previous year s annual meeting of stockholders.

Policy on Attending the Annual Meeting

We encourage, but do not require, all directors to attend our annual meetings of stockholders. With the exception of Mr. Brock, all of our directors attended our 2008 annual meeting of stockholders.

Stockholder Communications with the Board

Stockholders may communicate with the Board by sending a letter to the Board of Directors of Foothills Resources, Inc., c/o Office of the Secretary, 4540 California Avenue, Suite 550, Bakersfield, California 93309. All communications must contain a clear notation indicating that they are a Stockholder-Board Communication or Stockholder-Director Communication, and must identify the author as a stockholder. The office of the Secretary will receive the correspondence and forward it to any individual director or directors to whom the communication is directed, unless the communication is unduly hostile, threatening, or illegal, does not reasonably relate to our company or our business, or is similarly inappropriate. The office of the Secretary has authority to discard any inappropriate communications or to take other appropriate actions with respect to any inappropriate communications.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our directors, officers (including a person performing a principal policy-making function) and persons who own more than 10% of a registered class of our equity securities to file with the Securities and Exchange Commission initial reports of ownership and reports of changes in ownership of our common stock and other equity securities of ours. Directors, officers and 10% holders are required by Securities and Exchange Commission s regulations to send us copies of all of the Section 16(a) reports they file. Based solely upon a review of the copies of the forms sent to us and the representations made by the reporting persons to us, other than as described below, we believe that during the fiscal year ended December 31, 2008, our directors, officers and 10% holders complied with all filing requirements under Section 16(a) of the Exchange Act.

David A. Melman filed a delinquent Form 4 on December 31, 2008.
Francis P. Knuettel filed a delinquent Form 4 on December 1, 2008.
Michael L. Moustakis filed a delinquent Form 4 on September 23, 2008.
John L. Moran filed a delinquent Form 4 on September 11, 2008.
James H. Drennan filed a delinquent Form 3 on August 22, 2008.
Dennis B. Tower filed a delinquent Form 4 on April 9, 2008.
John L. Moran filed a delinquent Form 4 on April 9, 2008.
W. Kirk Bosché filed a delinquent Form 4 on April 9, 2008.
Dennis B. Tower filed a delinquent Form 4 on April 4, 2008.
John L. Moran filed a delinquent Form 4 on April 4, 2008.
W. Kirk Bosché filed a delinquent Form 4 on April 4, 2008.

Code of Ethics

The Company has not adopted a Code of Ethics, but may do so in the future.

Item 11. Executive Compensation.

Summary Compensation Table

The following table summarizes all compensation recorded by us in the last three completed fiscal years for our Chief Executive Officer, President, Chief Financial Officer, and the Company s two other executive officers Such officers are referred to herein as our Named Executive Officers.

Name and Principal Position	Year	Salary ($) (1)	Bonus ($)	Stock Awards ($)(2)	Option Awards ($) (2)	Non-equity Incentive Plan Compensation ($)	Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($) (3)	Total ($)
Dennis B. Tower	2008	190,000		15,000	37,964			7,600	250,564
Chief Executive	2007	190,000		26,048	37,964			2,850	256,862
Officer	2006	124,028	66,500		27,806				218,334
John L. Moran	2008	190,000		15,000	37,964				242,964
President	2007	190,000		26,048	37,964				254,012
	2006	124,028	66,500		27,806				218,334
W. Kirk Bosché	2008	175,000		10,000	26,335			9,095	220,430
Chief Financial	2007	175,000		17,365	25,309			5,012	222,686
Officer and Secretary	2006	114,236	111,250		18,537			2,692	246,715
Michael L. Moustakis	2008	180,000			75,753			8,880	264,633
Vice President,	2007	180,000			74,728			1,553	218,181
Engineering	2006	37,500	45,000		10,936			95	93,531
James H. Drennan	2008	150,000			66,390			6,317	222,707
Vice President,	2007	150,000			65,364			2,817	256,281
Land and Legal	2006	85,417			43,576			185	129,178

(1) Salaries are provided for 2008, 2007 and that part of 2006 during which each Named Executive Officer served as such. Messrs. Tower, Moran and Bosché commenced employment with the

Company on April 6, 2006. Mr. Moustakis and Mr. Drennan commenced employment with the Company on October 16, 2006, and May 1, 2006, respectively.

(2) Represents the dollar value recognized in 2008 as compensation expense for financial statement reporting purposes of restricted shares and options awarded in 2008 or earlier. See Note 5 to our Notes to Consolidated Financial Statements for a description of the assumptions made in the valuation of the restricted shares and options.

(3) Consists of the following:

   (a) Matching contributions to our 401(k) savings plan during 2008 and 2007, respectively, for the benefit of the Named Executive Officers in the amounts of $7,600 and $2,850 for Mr. Tower, $7,000 and $2,917 for Mr. Bosché, $7,200 and $903 for Mr. Moustakis, and $6,000 and $2,500 for Mr. Drennan; and

   (b) Life insurance premiums paid during 2008, 2007 and 2006, respectively, for the benefit of the Named Executive Officers in the amounts of $2,095, $2,095 and $2,692 for Mr. Bosché, $1,680, $650 and $95 for Mr. Moustakis, and $317, $317 and $185 for Mr. Drennan.

Employment Agreements

We have entered into executive employment agreements with Dennis B. Tower, our Chief Executive Officer, John L. Moran, our President, and W. Kirk Bosché, our Chief Financial Officer. Additionally, we entered into change in control/severance/retention agreements and written letters of employment with James H. Drennan, our Vice President, Land and Legal, and Michael L. Moustakis, our Vice President, Engineering.

Dennis B. Tower Chief Executive Officer

On April 6, 2006, we entered into an executive employment agreement with Mr. Tower, which we amended on December 10, 2008, which provides for an initial annual base salary of $190,000 and for unspecified annual bonuses as warranted. Under the agreement, Mr. Tower received options to purchase up to 300,000 shares of common stock, which options vest as follows: 25% of the shares of common stock underlying such option vested on the date of grant, and the remaining 75% of the shares of common stock underlying the option will vest in equal annual installments on the first, second and third anniversaries of the date of grant. Subsequent grants of stock options will vest and be exercisable pursuant to the terms and conditions of the 2007 Equity Incentive Plan.

Mr. Tower s employment agreement has an unspecified term of service subject to termination for cause and without cause, and provides for severance payments to Mr. Tower, in the event he is terminated without cause or he terminates the agreement for good reason, in the amount of two times total compensation for the prior year. Good reason includes an adverse change in the executive s position, title, duties or responsibilities, or any failure to re-elect him to such position (except for termination for cause). Mr. Tower s employment agreement includes standard indemnity, insurance, non-competition and confidentiality provisions.

John L. Moran President

On April 6, 2006, we entered into an executive employment agreement with Mr. Moran, which we amended on December 10, 2008, which provides for an initial annual base salary of $190,000 and for unspecified annual bonuses as warranted. Under the agreement, Mr. Moran received options to purchase up to 300,000 shares of common stock, which options vest as follows: 25% of the shares of common stock underlying such option vested on the date of grant, and the remaining 75% of the shares of common stock underlying the option will vest in equal annual installments on the first, second and third anniversaries of the date of grant. Subsequent grants of stock options will vest and be exercisable pursuant to the terms and conditions of the 2007 Equity Incentive Plan.

Mr. Moran s employment agreement has an unspecified term of service subject to termination for cause and without cause, and provides for severance payments to Mr. Moran, in the event he is terminated without cause or he terminates the agreement for good reason, in the amount of two times total compensation for the prior year. Good reason includes an adverse change in the executive s position, title, duties or responsibilities, or any failure to re-elect him to such position (except for termination for cause). Mr. Moran s employment agreement includes standard indemnity, insurance, non-competition and confidentiality provisions.

W. Kirk Bosché Chief Financial Officer

On April 6, 2006, we entered into an executive employment agreement with Mr. Bosché, which we amended on December 10, 2008, which provides for an initial annual base salary of $175,000 and for unspecified annual bonuses as warranted. Under the agreement, Mr. Bosché received options to purchase up to 200,000 shares of common stock, which options vest as follows: 25% of the shares of common stock underlying such option vested on the date of grant, and the remaining 75% of the shares of common stock underlying the option will vest in equal annual installments on the first, second and third anniversaries of the date of grant. Subsequent grants of stock options will vest and be exercisable pursuant to the terms and conditions of the 2007 Equity Incentive Plan.

Mr. Bosché s employment agreement has an unspecified term of service subject to termination for cause and without cause, and provides for severance payments to Mr. Bosché, in the event he is terminated without cause or he terminates the agreement for good reason, in the amount of two times total compensation for the prior year. Good reason includes an adverse change in the executive s position, title, duties or responsibilities, or any failure to re-elect him to such position (except for termination for cause). Mr. Bosché s employment agreement includes standard indemnity, insurance, non-competition and confidentiality provisions.

James H. Drennan Vice President, Land and Legal

On April 21, 2006, we entered into a written employment agreement with Mr. Drennan, effective as of May 1, 2006, which provides for an initial annual base salary of $125,000 and other unspecified annual bonuses as warranted. Under the agreement, Mr. Drennan is entitled to receive options to purchase up to 100,000 shares of our common stock, which options were awarded by our Board on May 2, 2006. These options vest as follows: 25% of the shares of common stock underlying such option vested on the date of grant, and the remaining 75% of the shares of common stock underlying the option will vest in equal annual installments on the first, second and third anniversaries of the date of grant. Subsequent grants of stock options will vest and be exercisable pursuant to the terms and conditions of the 2007 Equity Incentive Plan. Effective as of December 1, 2006, Mr. Drennan s annual base salary was increased to $150,000.

Mr. Drennan s employment agreement has an unspecified term of service and his employment is at will and subject to termination for any reason, without severance payment. In connection with his employment, Mr. Drennan also signed our standard Assignment of Invention and Non-Disclosure Agreement, Non-Solicitation Agreement, and Insider Trading and Disclosure Policy Acknowledgement.

Effective October 1, 2008, we entered into a change in control / severance / retention agreement with Mr. Drennan. The agreement provides for a payment to him in the amount of 75% of his annual salary if (i) on or before June 30, 2009, (a) there is a change in control of the Company, or (b) he is terminated as a result of a liquidation of the Company or a reduction in staff, or (c) he voluntarily terminates his employment as a result of a material diminishment of his responsibilities, a material reduction in his compensation, or a material change in the geographic location at which he performs services, or (ii) there is not a change in control of the Company before June 30, 2009, and he is employed by the Company on such date.

Michael L. Moustakis Vice President, Engineering

On October 4, 2006, we entered into a written employment agreement with Mr. Moustakis which provides for an initial annual base salary of $180,000, a hiring bonus of $45,000 and other unspecified annual bonuses as warranted. Under the agreement, Mr. Moustakis is entitled to receive options to purchase up to 200,000 shares of our common stock, which options were awarded by our Board on November 7, 2006. These options vest as follows: 25% of the shares of common stock underlying such option vested on the date of grant, and the remaining 75% of the shares of common stock underlying the option will vest in equal annual installments on the first, second and third anniversaries of the date of grant. Subsequent grants of stock options will vest and be exercisable pursuant to the terms and conditions of the 2007 Equity Incentive Plan.

Mr. Moustakis s employment agreement has an unspecified term of service and his employment is at will and subject to termination for any reason, without severance payment. In connection with his employment, Mr. Moustakis also signed our standard Assignment of Invention and Non-Disclosure Agreement, Non-Solicitation Agreement, and Insider Trading and Disclosure Policy Acknowledgement.

Effective October 1, 2008, we entered into a change in control / severance / retention agreement with Mr. Moustakis. The agreement provides for a payment to him in the amount of 75% of his annual salary if (i) on or before June 30, 2009, (a) there is a change in control of the Company, or (b) he is terminated as a result of a liquidation of the Company or a reduction in staff, or (c) he voluntarily terminates his employment as a result of a material diminishment of his responsibilities, a material reduction in his compensation, or a material change in the geographic location at which he performs services, or (ii) there is not a change in control of the Company before June 30, 2009, and he is employed by the Company on such date.

Outstanding Equity Awards at Fiscal Year End

The following table provides information concerning unexercised options, stock that has not vested and equity incentive plan awards for each of our Named Executive Officers as of December 31, 2008.

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Share or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Dennis B. Tower	225,000	75,000(1)		$0.70	4/6/2016	13,236(3)	199		
John L. Moran	225,000	75,000(1)		$0.70	4/6/2016	13,236(3)	199		
W. Kirk Bosché	150,000	50,000(1)		$0.70	4/6/2016	8,824(3)	132		
W. Kirk Bosché	25,000	75,000(2)		$0.14	8/20/2018				
Michael L. Moustakis	150,000	50,000(1)		$1.99	11/7/2016				
Michael L. Moustakis	25,000	75,000(2)		$0.14	8/20/2018				
James H. Drennan	75,000	25,000(1)		$3.59	5/2/2016				
James H. Drennan	25,000	75,000(2)		$0.14	8/20/2018				

(1) The right to exercise these shares will vest on April 6, 2009, for Messrs. Tower,

Moran and Bosché, on November 7, 2009, for Mr. Moustakis, and on May 2, 2009, for Mr. Drennan, in each such case if the Named Executive Officer is still employed by the Company on such date.

(2) The right to exercise these shares will vest in three equal annual installments beginning August 20, 2009, in each case if the Named Executive Officer is still employed by the Company on such date.

(3) These shares will vest on April 6, 2009, in each case if the Named Executive Officer is still employed by the Company on such date.

Director Compensation

The following table provides information concerning the compensation of directors who are not Named Executive Officers for the year ended December 31, 2008:

Fees Earned or	Stock	Option	Non-equity Incentive Plan Compensation	Nonqualified Deferred Compensation	All Other Compensation

Name	Paid in Cash ($)	Awards ($)	Awards ($)	($)	Earnings ($)	($)	Total ($)
John A. Brock	15,000		37,364(1)				52,364
Ralph J. Goehring	5,000		1,025(2)				6,025
Frank P. Knuettel	10,000		50,157(1)				60,157
David A. Melman	15,000		22,832(1)				37,832
Christopher P. Moyes						207,665(3)	207,665

(1) Represents the dollar value recognized in 2008 as compensation expense for financial statement reporting purposes of options awarded prior to fiscal year 2008. See Note 5 to our Notes to Consolidated Financial Statements for a description of the assumptions made in the valuation of the options. The grant-date fair values per option for Messrs. Brock, Knuettel and Melman were $1.12, $1.50 and $0.68, respectively. One-hundred thousand stock option awards remain outstanding.

(2) Represents the dollar value

recognized in 2008 as compensation expense for financial statement reporting purposes of options awarded in fiscal year 2008. See Note 5 to our Notes to Consolidated Financial

Statements for a description of the assumptions made in the valuation of the options. The grant-date fair value per option for Mr. Goehring was $0.08. One-hundred thousand stock option awards remain outstanding.

(3) Includes fees payable for fiscal year 2008 under our consulting agreement with Moyes & Co., Inc. Prior to the termination of the agreement effective November 30, 2008, Moyes & Co., Inc. identified potential acquisition, development, exploitation and exploration opportunities that fit with our strategy, and was expected to screen opportunities and perform detailed evaluation of those opportunities that we decided

to pursue, as well as assist with due diligence and negotiations with respect to such opportunities. Mr. Moyes is a major stockholder and the President of Moyes & Co., Inc. Pursuant to the terms of our agreement with Moyes & Co., Inc., Mr. Moyes did not receive any further compensation for serving on our Board.

Directors who are not also executive officers of the Company receive a standard fee of $5,000 for each non-telephonic meeting of the Board that such directors attend. Additionally, for such meetings, the Company reimburses the non-management directors for reasonable travel expenses. The directors do not receive a per-meeting fee for telephonic meetings of the Board.

In addition to the cash consideration set forth above our non-employee directors are also eligible to receive equity awards at the discretion of the Board under our 2007 Equity Incentive Plan. Traditionally our non-employee directors, with the exception of Mr. Moyes, have received grants of options to purchase shares of our common stock in consideration of their services following their election to the Board. Mr. Goehring was issued 100,000 options to purchase shares of our common stock following his election to the Board in July 2008. Other than the award to Mr. Goehring no equity compensation was paid to our non-employee directors in fiscal 2008.

Mr. Tower and Mr. Moran have entered into employment agreements with the Company, which are explained in detail above. Neither Mr. Tower nor Mr. Moran receives the $5,000 fee for attending non-telephonic meetings of the Board. Additionally, options granted to each of Mr. Tower and Mr. Moran to date have been granted pursuant to their employment agreements with the Company, though there is no prohibition on further grants by the Board under the 2007 Equity Incentive Plan on the basis of Mr. Tower s and Mr. Moran s service on the Board.

Mr. Moyes has foregone the compensation described above, pursuant to the terms of our retainer agreement with Moyes & Co., Inc., dated April 7, 2006. Under our retainer agreement, which was terminated effective November 30, 2008, we paid Moyes & Co., Inc. a monthly retainer of $17,500 and additional fees for services requested that exceeded those covered by the retainer, and reimbursed normal business travel and other expenses, in exchange for Moyes & Co., Inc. s services to us. Moyes & Co., Inc. identified potential acquisition, development, exploitation and exploration opportunities which fit with our operating strategy. Additionally, Moyes & Co., Inc. initially screened such opportunities, performed detailed evaluations of each potential opportunity, and assisted with due diligence and negotiations of those opportunities we decided to pursue.

Compensation Committee Interlocks and Insider Participation

The Compensation Committee consists of Messrs. Brock, Goehring, and Melman. Our Compensation Committee is comprised entirely of independent directors.

Compensation Committee Report

The Compensation Committee has reviewed and discussed with management the Compensation Discussion and Analysis. Based on such review and discussions, the Compensation Committee recommended to the Board that the Compensation Discussion and Analysis be included in this Form 10-K.

The Compensation Committee
John A. Brock
Ralph J. Goehring
David A. Melman

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.
Principal Stockholders

The following table sets forth certain information regarding the beneficial ownership of our common stock as of March 31, 2009. The table sets forth the beneficial ownership of (i) each person who, to our knowledge, beneficially owns more than 5% of the outstanding shares of common stock; (ii) each of our directors and executive officers; and (iii) all of our executive officers and directors as a group. The number of shares owned includes all shares beneficially owned by such persons, as calculated in accordance with Rule 13d-3 promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act), and such information is not necessarily indicative of beneficial ownership for any other purpose. Under such rules, beneficial ownership includes any shares of our common stock as to which a person has sole or shared voting power or investment power and any shares of common stock which the person has the right to acquire within 60 days of March 31, 2009, through the exercise of any option, warrant or right, through conversion of any security or pursuant to the automatic termination of a power of attorney or revocation of a trust, discretionary account or similar arrangement. Beneficial ownership percentages are calculated based on 60,557,637 shares of common stock issued and outstanding as of March 31, 2009. The address of each executive officer and director is c/o Foothills Resources, Inc., 4540 California Avenue, Suite 550, Bakersfield, California 93309.

	Beneficial Ownership	
Beneficial Owner	Number of Shares (#)	Percent of Total (%)
Dennis B. Tower (1)	5,329,783	8.7%
John L. Moran (2)	5,287,158	8.7%
W. Kirk Bosché (3)	3,458,176	5.7%
Christopher P. Moyes (4)	1,520,475	2.5%
Michael L. Moustakis (5)	368,000	*
James H. Drennan (6)	125,000	*
Frank P. Knuettel (7)	225,001	*
John A. Brock (8)	75,000	*
David A. Melman (9)	112,500	*
Ralph J. Goehring (10)	125,000	*
Goldman, Sachs & Co. (11)	8,000,000	12.3%
Executive Officers and Directors as Group	16,626,093	26.7%

* Denotes less than 1%

Notes:

(1) Includes warrants to acquire 112,500 shares of common stock purchased in the April 2006 offering and exercisable within 60 days of March 31, 2009. Includes options exercisable within 60 days to acquire 300,000 shares of common stock. Includes 35,564 shares of restricted stock awarded under our 2007 Equity Incentive Plan. Includes 4,467,383 shares of common stock owned by The Tower Family Trust.

(2) Includes options exercisable within 60 days of March 31, 2009, to acquire 300,000 shares of common stock. Includes 35,439 shares of restricted stock awarded under our 2007 Equity Incentive Plan.

(3) Includes warrants to

acquire 54,000 shares of common stock purchased in the April 2006 offering and exercisable within 60 days of March 31, 2009. Includes options exercisable within 60 days of March 31, 2009, to acquire 225,000 shares of common stock. Includes 23,964 shares of restricted stock awarded under our 2007 Equity Incentive Plan.

(4) Includes 217,188 shares of common stock held by MMP LLP, in which Mr. Moyes is a partner. Includes warrants to acquire 25,500 shares of common stock exercisable within 60 days of March 31, 2009, which warrants were purchased by Choregus Master Trust, Plan I, Money Purchase and Choregus Master Trust, Plan II, Profit Sharing in the April 2006 offering, and of

which warrants Mr. Moyes is deemed to be the beneficial owner.

(5) Includes options exercisable within 60 days of March 31, 2009, to acquire 175,000 shares of common stock.

(6) Includes options exercisable within 60 days of March 31, 2009, to acquire 125,000 shares of common stock.

(7) Includes options exercisable within 60 days of March 31, 2009, to acquire 100,000 shares of common stock. Also includes 71,429 shares of common stock and warrants to acquire 53,572 shares of common stock exercisable within 60 days, which shares and warrants were purchased by Francis P. Knuettel as Trustee of the Francis P. Knuettel Rev LVG TR UA DTD 3/7/03.

(8) Includes options exercisable within 60 days of March 31, 2009, to acquire 75,000 shares of common stock.

(9) Includes options exercisable within 60 days of March 31, 2009, to acquire 75,000 shares of common stock. Also includes warrants to acquire 37,500 shares of common stock purchased in the April 2006 offering and exercisable within 60 days of March 31, 2009.

(10) Includes options exercisable within 60 days of March 31, 2009, to acquire 25,000 shares of common stock.

(11) Includes warrants to acquire 4,666,667 shares of common stock acquired in the September 2006 offering and exercisable within 60 days of March 31, 2009. The address of

Goldman, Sachs & Co. is 85 Broad Street, New York, New York 10004. The information included herein is based solely upon a Schedule 13G filed by Goldman Sachs & Co. on October 10, 2006.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

Certain Transactions with Directors and Executive Officers

Except as disclosed below, neither our directors or executive officers, nor any of their respective associates or affiliates, had any material interest, direct or indirect, in any material transaction to which we were a party during fiscal 2008, or which is presently proposed.

In April 2006, we entered into an agreement with Moyes & Co., Inc. to identify potential acquisition, development, exploitation and exploration opportunities that fit with our strategy. Prior to the termination of the agreement effective November 30, 2008, Moyes & Co., Inc. screened opportunities and performed detailed evaluation of those opportunities that we decided to pursue, and assisted with due diligence and negotiations with respect to such opportunities. Christopher P. Moyes was the beneficial owner of 2.5% of our common stock as of March 31, 2009, and is a member of our Board. Mr. Moyes is a major stockholder and the President of Moyes & Co., Inc. Because Moyes & Co., Inc. was being compensated for identifying opportunities and assisting us in pursuing those opportunities, the interests of Moyes & Co., Inc. were not the same as our interests. We were responsible for evaluating any opportunities presented to us by Moyes & Co., Inc. to determine if those opportunities were consistent with our business strategy.

Mr. Moyes has foregone his compensation as a director, pursuant to the terms of our agreement with Moyes & Co., Inc. Under the agreement, we paid Moyes & Co., Inc. a monthly retainer of $17,500 and additional fees for services requested that exceeded those covered by the retainer, and reimbursed normal business travel and other expenses, in exchange for Moyes & Co., Inc. s services to us.

Pursuant to our business plan with respect to the Anadarko Basin in southwest Oklahoma, we acquired non-exclusive rights to a 3D seismic survey in Roger Mills County, Oklahoma as a result of the merger of TeTra Ex, Inc. (TeTra), a company owned by John Moran, our President, into a wholly owned subsidiary of Foothills in October 2008. TeTra reprocessed the 3D survey, completed geological and geophysical interpretations of the survey data, and identified drillable prospects. We have acquired oil and gas leases over those prospects, and plan to negotiate joint ventures with other companies. Mr. Moran and John A. Brock, a director of Foothills, are or will be entitled to receive an assignment of an overriding royalty interest on any oil and gas leases acquired by the Company over such prospects, with the amount of the overriding royalty interest determined in accordance with a sliding scale formula based on the lessor royalty interest in such leases.

Director Independence

During 2008, our Board consisted of seven directors upon the election of Mr. Goehring as a director. We adhere to the Nasdaq Marketplace Rules in determining whether a director is independent and our Board has determined that four of our seven directors, Messrs. Brock, Goehring, Knuettel and Melman, are independent within the meaning of Rule 4200(a)(15) of the NASDAQ Manual.

Item 14. Principal Accountant Fees and Services.

The following table sets forth the aggregate fees billed to the Company by Brown Armstrong Paulden McCown Starbuck Thornburgh & Keeter Accountancy Corporation (Brown Armstrong) for the audit of our financial statements for 2008 and 2007, and for other services provided by that firm during those periods:

	Year Ended December 31,	
	2008	2007
Audit fees	$ 62,477	$ 67,393
Audit-related fees	1,600	3,500
Tax fees	46,043	23,408
All other fees		
Total fees	$ 110,120	$ 94,301

Audit-Related Fees billed during fiscal 2008 and 2007 were for services related to reviews of a Form S-1 filed with the Securities and Exchange Commission. Tax Fees billed during fiscal 2008 and 2007 were for professional services rendered for tax compliance, tax advice and tax planning.

Pre-Approval Policy

The Board has adopted a policy for the pre-approval of all audit and non-audit services to be performed for us by our independent registered public accounting firm. The Board considered the role of Brown Armstrong in providing audit, audit-related and tax services to us and concluded that such services were compatible with Brown Armstrong s role as our independent registered public accounting firm.

Item 15. Exhibits and Financial Statement Schedules.

(a) (1) FINANCIAL STATEMENTS The following consolidated financial statements of Foothills Resources, Inc. and Subsidiaries contained under Item 8 of this Form 10-K are incorporated herein by reference:

Consolidated Balance Sheets as of December 31, 2008 and December 31, 2007

Consolidated Statements of Operations for the years ended December 31, 2008, 2007 and 2006

Consolidated Statements of Cash Flows for the years ended December 31, 2008, 2007 and 2006

Consolidated Statements of Stockholders Equity (Deficit) for the years ended December 31, 2008, 2007 and 2006

(2) FINANCIAL STATEMENT SCHEDULES All financial statement schedules have been omitted because they are not applicable or are not required, or because the information required to be set forth therein is included in the Consolidated Financial Statements or Notes thereto.

(3) EXHIBITS See Exhibit Index on page 76 of this Annual Report on Form 10-K.

EXHIBIT INDEX

Exhibit No.	**Description**
2.1	Agreement and Plan of Merger and Reorganization, dated as of April 6, 2006, by and between Foothills Resources, Inc., a Nevada corporation, Brasada Acquisition Corp., a Delaware corporation and Brasada California, Inc., a Delaware corporation. (1)
3.1	Articles of Incorporation of Foothills Resources, Inc. (2)
3.2	Certificate of Amendment of the Articles of Incorporation of Foothills Resources, Inc. (3)
3.3	Articles of Amendment to the Articles of Incorporation of Foothills Resources, Inc. (4)
3.4	Bylaws of Foothills Resources, Inc. (5)
3.5	Amended and Restated Articles of Incorporation of Foothills Resources, Inc. (6)
3.6	Amended and Restated Bylaws of Foothills Resources, Inc. (7)
4.1	Specimen Stock Certificate of Foothills Resources, Inc. (8)
4.2	Form of Warrant issued to the Investors in the Private Placement Offering, April 6, 2006. (9)
4.3	Warrant issued to Goldman, Sachs & Co. in connection with the Credit Agreement, dated as of September 8, 2006. (10)
4.4	Warrant issued to Goldman, Sachs & Co. in the offering, dated as of September 8, 2006. (11)
4.5	Form of Warrant issued to the Investors in the Private Placement Offering, September 8, 2006. (12)

4.6	Warrant issued to Regiment Capital Special Situations Fund III, L.P. in connection with the Credit Agreement, dated December 13, 2007. (13)
10.1	Employment Agreement, dated April 6, 2006, by and between Foothills Resources, Inc. and Dennis B. Tower. (14)
10.2	Employment Agreement, dated April 6, 2006, by and between Foothills Resources, Inc. and John L. Moran. (15)

Exhibit No.	Description
10.3	Employment Agreement, dated April 6, 2006, by and between Foothills Resources, Inc. and W. Kirk Bosché. (16)
10.4	Employment Offer Letter and Agreement, dated April 21, 2006, by and between Foothills Resources, Inc. and James Drennan. (17)
10.5	Form of Indemnity Agreement by and between Foothills Resources, Inc. and the Directors and Officers of Foothills Resources, Inc. (18)
10.6	Farmout and Participation Agreement, dated as of January 3, 2006, by and between INNEX California, Inc. and Brasada Resources, LLC. (19)
10.6	Registration Rights Agreement, dated as of September 8, 2006, by and between Foothills Resources, Inc. and TARH E&P Holdings, L.P. (20)
10.7	Conveyance of Overriding Royalty Interest, dated as of September 8, 2006, from Foothills Texas, Inc. to MTGLQ Investors, L.P. (21)
10.8	Employment Agreement, dated October 4, 2006, by and between Foothills Resources, Inc. and Michael Moustakis. (22)
10.9	Credit Agreement, dated as of December 13, 2007, by and among Foothills Resources, Inc., certain subsidiaries of Foothills Resources, Inc., various lenders and Wells Fargo Foothill, LLC. (23)
10.10	Security Agreement, dated as of December 13, 2007, among Foothills California, Inc., Foothills Texas, Inc. and Foothills Oklahoma, Inc. as Grantors and Wells Fargo Foothill, LLC. (24)
10.11	Forbearance Agreement, dated as of August 13, 2008, among Foothills and each of its subsidiaries as borrowers, various lenders and Wells Fargo Foothill, LLC as agent. (25)
10.12	Third Amendment to Credit Agreement and Amended and Restated Forbearance Agreement, dated as of September 15, 2008, among Foothills and each of its subsidiaries as borrowers, various lenders and Wells Fargo Foothill, LLC as agent. (26)
10.13	Limited Waiver to Credit Agreement and Amendment to Third Amendment to Credit Agreement and Amended and Restated Forbearance Agreement, dated as of December 2, 2008. (27)
10.14	Amended and Restated Employment Agreement, dated as of December 10, 2008, by and among Foothills Resources, Inc. and Dennis B. Tower (28)
10.15	Amended and Restated Employment Agreement, dated as of December 10, 2008, by and among Foothills Resources, Inc. and John L. Moran (29)
10.16	Amended and Restated Employment Agreement, dated as of December 10, 2008, by and among Foothills Resources, Inc. and W. Kirk Bosché (30)

10.17	DIP Credit Agreement, dated as of February 23, 2009, among Foothills Resources, Inc., each of its subsidiaries, various lenders, and Regiment Capital Special Situations Fund III, L.P. (31)
10.18	Change in Control / Severance / Retention Agreement, dated as of October 1, 2008, by and among Foothills Resources, Inc. and James H. Drennan
10.19	Change in Control / Severance / Retention Agreement, dated as of October 1, 2008, by and among Foothills Resources, Inc. and Michael L. Moustakis
21.1	List of subsidiaries
23.1	Consent of Independent Registered Public Accounting Firm.
23.2	Consent of Independent Reservoir Engineers.
24.1	Powers of Attorney. (32)
31.1	Certification of Principal Executive Officer, pursuant to Rule 13a-14 and 15d-14 of the Securities Exchange Act of 1934.
31.2	Certification of Principal Financial Officer, pursuant to Rule 13a-14 and 15d-14 of the Securities Exchange Act of 1934.

Exhibit No.	**Description**
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Filed herewith.

1. Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 6, 2006 (File No. 001-31547).

2. Incorporated by reference to Exhibit 3.1 to the Registration Statement on Form SB-2/A filed with the Securities and Exchange Commission on June 18, 2001 (File No. 333-59708).

3. Incorporated by reference to Exhibit 3.2 to the Registration Statement on Form SB-2/A filed with the Securities and Exchange Commission on June 18, 2001 (File

No. 333-59708).

4. Incorporated by reference to Exhibit 3.3 to the Form 10-KSB filed with the Securities and Exchange Commission on March 28, 2008 (File No. 001-31547).

5. Incorporated by reference to Exhibit 3.3 to the Registration Statement on Form SB-2/A filed with the Securities and Exchange Commission on June 18, 2001 (File No. 333-59708).

6. Incorporated by reference to Exhibit 3.5 to the Form 10-Q filed with the Securities and Exchange Commission on November 14, 2008 (File No. 001-31547).

7. Incorporated by reference to Exhibit 3.6 to the Form 10-Q filed with the Securities and Exchange Commission on November 14, 2008 (File No. 001-31547).

8.

Incorporated by reference to Exhibit 4.1 to the Registration Statement on Form SB-2/A filed with the Securities and Exchange Commission on June 18, 2001 (File No. 333-59708).

9. Incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 6, 2006 (File No. 001-31547).

10. Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on September 11, 2006 (File No. 001-31547).

11. Incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on September 11, 2006 (File No. 001-31547).

12.

Incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on September 11, 2006 (File No. 001-31547).

13. Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on December 17, 2007 (File No. 001-31547).

14. Incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 6, 2006 (File No. 001-31547).

15. Incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 6, 2006 (File No. 001-31547).

16. Incorporated by reference to Exhibit 10.6 to the

Current Report on Form 8-K filed with the Securities and Exchange Commission on April 6, 2006 (File No. 001-31547).

17. Incorporated by reference to Exhibit 10.7 to the Registration Statement on Form SB-2 filed with the Securities and Exchange Commission on October 10, 2006 (File No. 333-137925).

18. Incorporated by reference to Exhibit 10.7 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 6, 2006 (File No. 001-31547).

19. Incorporated by reference to Exhibit 10.8 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 6, 2006 (File No. 001-31547).

20. Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on September 11, 2006 (File No. 001-31547).

21. Incorporated by reference to Exhibit 10.7 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on September 11, 2006 (File No. 001-31547).

22.

Incorporated by reference to Exhibit 10.24 to the Registration Statement on Form SB-2/A filed with the Securities and Exchange Commission on December 14, 2006 (File No. 333-137925).

23. Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on December 17, 2007 (File No. 001-31547).

24. Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on December 17, 2007 (File No. 001-31547).

25. Incorporated by reference to Exhibit 10.21 to the Form 10-Q filed with the Securities and Exchange Commission on August 14, 2008 (File No. 001-31547).

26.

Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on October 21, 2008 (File No. 001-31546).

27. Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on December 8, 2008 (File No. 001-31546).

28. Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on December 15, 2008 (File No. 001-31546).

29. Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on December 15, 2008 (File No. 001-31546).

30. Incorporated by reference to Exhibit 10.3 to the

Current Report on Form 8-K filed with the Securities and Exchange Commission on December 15, 2008 (File No. 001-31546).

31. Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on February 27, 2009 (File No. 001-31546).
32. Incorporated by reference to the signature page of this Annual Report on Form 10-K.

SIGNATURES

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

Dated: May 11, 2009	FOOTHILLS RESOURCES, INC.
	/s/ Dennis B. Tower Dennis B. Tower Chief Executive Officer

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints each of Dennis B. Tower and W. Kirk Bosché, as his true and lawful attorneys-in-fact and agents each with full power of substitution and resubstitution, for him and his name, place and stead, in any and all capacities, to sign any or all amendments to this Annual Report on Form 10-K and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent, full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the foregoing, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, may lawfully do or cause to be done by virtue hereof.

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

Name	Position	Date
/s/ Dennis B. Tower Dennis B. Tower	Chief Executive Officer, Director (Principal Executive Officer)	May 11, 2009
/s/ John L. Moran John L. Moran	President, Director	May 11, 2009
/s/ W. Kirk Bosché W. Kirk Bosché	Chief Financial Officer (Principal Financial Officer)	May 11, 2009
/s/ John A. Brock John A. Brock	Director	May 11, 2009
/s/ Ralph J. Goehring Ralph J. Goehring	Director	May 11, 2009
/s/ Frank P. Knuettel Frank P. Knuettel	Director	May 11, 2009
/s/ David A. Melman	Director	May 11, 2009

David A. Melman

/s/ Christopher P. Moyes	Director	May 11, 2009
Christopher P. Moyes		