GEOPETRO RESOURCES CO
Form 10-K
March 31, 2010
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2009

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 001-16749

GeoPetro Resources Company

(Exact name of registrant as specified in its charter)

California	**94-3214487**
(State of incorporation)	(IRS Employer Identification Number)
One Maritime Plaza, Suite 700 **San Francisco, CA**	**94111**
(Address of principal executive offices)	(Zip Code)

(415) 398-8186

(Registrant s telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, No Par Value	NYSE Amex US

Securities registered pursuant to Section 12(g) of the Act: **None**

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

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 x

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 x 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 (§ 232.405 of this chapter) 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 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 amendment to this Form 10-K. o

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

Large accelerated filer o	Accelerated filer o
Non-accelerated filer ¨	Smaller Reporting Company x

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

The aggregate market value of the registrant s common stock held by non-affiliates was approximately $13,102,558 based on the closing sale price of $0.47 per share as reported by the American Stock Exchange on June 30, 2009.

The number of shares of the registrant s common stock outstanding on March 30, 2010 was 34,284,646.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s Proxy Statement relating to the 2010 Annual Meeting of Shareholders to be filed on or before April 30, 2010, are incorporated by reference into Part III of this Form 10-K.

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GEOPETRO RESOURCES COMPANY

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Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act as of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended and we intend that such forward-looking statements be subject to the safe harbors created thereby. These statements are related to future events or our future financial performance. We have attempted to identify forward-looking statements with terminology, including anticipate, believe, can, continue, could, estimate, expect, intend, may, plan, will, or similar expressions as they relate to us and our business, industry and markets. All statements other than statements of historical fact are statements that could be deemed forward-looking statements, such as those statements that address activities, events or developments that we expect, believe or anticipate will or may occur in the future. These statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Such forward looking statements are subject to change based on factors beyond our control. Certain factors that may affect our financial condition and results of operations are discussed in Item 1A Risk Factors , Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 7A Quantitative and Qualitative Disclosures About Market Risk of this Annual Report on Form 10-K, and may be discussed from time to time in our reports filed with the Securities and Exchange Commission subsequent to this report. We assume no obligation, nor do we intend to update these forward-looking statements, unless required by law. Unless the context requires otherwise, references in this Annual Report on Form 10-K to GeoPetro, Company , we, us and our refer to GeoPetro Resources Company and its consolidated subsidiaries.

PART I

Item 1. *Business*

We were incorporated in the State of Wyoming in August 1994 under the name GeoPetro Company as an oil and gas exploration, development drilling and production company. In June 1996, we merged with our wholly-owned subsidiary, GeoPetro Resources Subsidiary Company, a California corporation, and the resulting merged company is incorporated in the state of California under the California General Corporation Law under the name GeoPetro Resources Company.

Our principal and registered office is located at One Maritime Plaza, Suite 700, San Francisco, California, USA 94111. We maintain a website located at www.geopetro.com.

Intercorporate Relationships

We hold 100% of the shares of Redwood Energy Company, a Texas corporation, **Redwood.** Redwood is the general partner of, and holds a 5% interest in, Redwood Energy Production, L.P., **Redwood LP** , a Texas limited partnership. We are the sole limited partner of Redwood LP and own the remaining 95% partnership interest in Redwood LP. Redwood also holds a 100% interest in Madisonville Midstream LLC, **Madisonville Midstream** , a Texas limited liability company.

In addition, we hold a 12% interest in Continental-GeoPetro (Bengara II) Ltd., **C-G Bengara** which is a British Virgin Islands company and a 50% interest in CG Xploration Inc., **CG Xploration** , which is a Delaware corporation.

We also hold 100% of the shares of GeoPetro Canada Ltd., **GeoPetro Canada** , an Alberta company, 100% of the shares of GeoPetro Alaska LLC **GeoPetro Alaska** , an Alaska limited liability company, and 100% of the shares of South Texas GeoPetro, LLC, **South Texas GeoPetro** , a Texas limited liability company.

Our Company also holds 100% of the shares of GeoPetro International Ltd., a British Virgin Islands company.

GENERAL DEVELOPMENT OF THE BUSINESS

During the past three years, we have conducted leasehold acquisition, exploration and drilling activities on our North American and Indonesian prospects. These projects currently encompass approximately 377,506 gross (163,590 net) acres, consisting of mineral leases, production sharing contracts and exploration permits that give us the right to explore for, develop and produce oil and natural gas. Most of these properties are in the exploration, appraisal or development drilling phase and have not begun to produce revenue from the sale of oil and natural gas. Excluding minor interest and dividend income, our only cash inflows until 2003 were the recovery of capital invested in projects through sale or other divestiture of interests in oil and gas prospects to industry partners.

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In December 2000, we acquired working interests in oil and natural gas leases in the Madisonville Field in Madison County, Texas, including interests in the Rodessa Formation. Also included in the acquisition was the Magness Well, an existing well that had been drilled, cased and production tested in the Rodessa Formation. In October 2001, we re-completed and tested the Magness Well over a 12-day period. In October 2002, we drilled, completed and successfully tested an injection well to dispose of waste products resulting from the treating process for gas produced from the Rodessa Formation. The Madisonville Field gas treatment plant and associated pipelines, which were built specifically for this project, were placed into service in May 2003, and the Magness Well began production in late May 2003. Since 2003, substantially all of our revenue has been generated from natural gas sales derived from the Madisonville Field, and the Madisonville Project was our primary source of revenue in 2009. The first development well in the Madisonville Field, the Fannin Well, was drilled in 2005 and was tested at rates of up to 25.7 MMcf/d. In 2006, we drilled the Wilson and Mitchell wells. Presently, the Fannin, Mitchell and Magness wells are producing while the Wilson well is shut-in awaiting a fracture stimulation. We own a 100% working interest in the four wells. Historically, our wells have been production constrained by the gas treatment plant at the Madisonville Field, which had a design treating capacity limit of approximately 18,000 Mcf per day. In 2005, we entered into an agreement with the then plant owner, Madisonville Gas Processing, LP (MGP), an unaffiliated third party, which required, among other things, that MGP expand the design treating capacity of the plant from 18,000 to 68,000 Mcf per day to treat additional volumes from our producing wells. In late 2007, MGP began operations of the additional treating facilities and the additional treating capacity at such facilities; however, full operations were never reached due to the presence of diamondoids in the gas stream produced from the Rodessa Formation. On December 31, 2008, GeoPetro acquired the MGP gas treatment plant, as well as the related gas gathering pipelines and facilities. This acquisition has allowed the Company to improve operating efficiencies by consolidating the upstream and midstream portions of Madisonville project. By owning the midstream portion of the Madisonville project, we not only expect better net price realizations and operational efficiencies (i.e. improved volume realizations), but we also will control the timing and design of the current expansion of the plant facilities as well as future expansions, if needed. See Properties Description of the Properties Texas The Madisonville Midstream Gas Treatment Plant and Gathering Facilities.

In February 2010, we sold our entire working interest in our Alaskan Cook Inlet Project for cash and retained certain royalties. See Properties Description of the Properties Alaska Alaskan Cook Inlet Project.

As of March 31, 2010, we have 34,284,646 shares of common stock and 7,523,000 shares of Series B convertible preferred stock outstanding.

Growth Strategy

Our growth strategy is to maximize shareholder value through the exploration and development drilling of oil and natural gas prospects. To carry out this philosophy we employ the following business strategies:

- identify and pursue potential projects which individually have the potential to be company makers which we define as projects which could generate a minimum unrisked net present value of $50 million net to our interest using a 10% discount factor;

- perform geological, engineering and geophysical evaluations;

- gain control of key acreage;

- generate high quality drillable exploration and development drilling prospects;

- retain a large working interest in those projects which involve low risk appraisal or development drilling, exploitation or appraisal of proved, probable and possible reserves; and

- minimize early investment and exploration risk in higher risk exploratory prospects through farmouts to other oil and natural gas companies and maintain meaningful interests with a carry through the exploration phase.

Risks Associated With Foreign Operations

Our business activities in Indonesia, Canada and the United States are subject to political and economic risks, including: loss of revenue, property and equipment as a result of unforeseen events like expropriation, nationalization, war, terrorist attacks and insurrection; risks of increases in import, export and transportation regulations and tariffs, taxes and governmental royalties; renegotiation of contracts with governmental entities; changes in laws and policies governing operations of foreign-based companies in Indonesia; exchange controls, and numerous other factors. While we expect these risks are greater in Indonesia,

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especially political risk, any one or more of such political or economic conditions could change in the United States or Canada to our detriment. For a related discussion of the risks attendant with our foreign operations, see Risk Factors.

Financial Information About Geographic Areas

Please see the notes to the financial statements for information concerning oil and gas properties located in the United States and foreign countries.

Regulations

Domestic exploration, production and sale of oil and gas are extensively regulated at both the federal and state levels. Our business is and will be directly or indirectly affected by numerous governmental laws and regulations applicable to the energy industry, including:

- Federal environmental laws and regulations
- State environmental laws and regulations
- Local environmental laws and regulations
- Federal energy laws and regulations
- Conservation laws and regulations
- Tax and other laws and regulations pertaining to the energy industry

Legislation, rules and regulations affecting the oil and gas industry are under constant review for amendment or expansion, frequently increasing the regulatory burden. Any changes in the existing legislation, rules or regulations could adversely affect our business. The regulatory burdens are often costly to comply with and carry substantial penalties for failure to comply.

As of December 2009, we have re-completed an existing producing well and drilled three additional wells and an injection well in the Madisonville Project as operator. In addition, we may drill oil, gas and disposal wells in the future as the operator and will be required to obtain local government and other permits to drill such wells. There can be no assurance that such permits will be available on a timely basis or at all. Texas and other states have statutes or regulations pertaining to conservation matters which, among other matters, regulate the unitization or pooling of gas properties and the spacing, plugging and abandonment of such wells and set limits on the maximum rates of natural gas that can be produced from gas wells.

Our operations and activities are subject to numerous federal, state and local environmental laws and regulations. These laws and regulations:

- Require the acquisition of permits
- Restrict the type, quantities and concentration of various substances that can be discharged into the environment

- Limit or prohibit drilling and other activities on wetlands and other designated, protected areas

- Regulate the generation, handling, storage, transportation, disposal and treatment of waste materials

- Impose criminal or civil liabilities for pollution resulting from oil and natural gas operations

We expect that with the increase in our exploratory and development drilling activities, the impact of environmental laws and regulations on our business and operations will also increase. We may be required in the future to make substantial outlays of money to comply with environmental laws and regulations. Additional changes in operating procedures and expenditures to comply with future environmental laws cannot be predicted.

Other than our U.S. projects, we do not operate oil and gas properties in which we own an interest. In those instances, we are not in the position to exert direct control over compliance with most of the rules and regulations discussed above. We are substantially dependent on the operators of our non-operated oil and gas properties to monitor, administer and oversee such compliance. The failure of the operator to comply with such rules and regulations could result in substantial liabilities to us.

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As the operator of the Madisonville Project, among other various environmental laws and regulations, we are subject to the U.S. Comprehensive Environmental Response, Compensation and Liability Act (**CERCLA**) and any comparable legislation adopted by Texas which imposes strict, joint and several liability on owners and operators of properties and on persons who dispose or arrange for the disposal of hazardous substances found on or under the sites of such properties.

Under CERCLA, one owner, lessee or other party, having responsibility for and an interest in a site requiring cleanup may, under certain circumstances, be required to bear a disproportionate share of liability for the cost of such cleanup if payments cannot be obtained from other responsible parties. The Resource Conservation and Recovery Act (**RCRA**) and comparable rules adopted by Texas and other states regulate the generation, management and disposal of hazardous oil and gas waste.

The Texas Railroad Commission has been delegated the responsibility and authority to regulate and prevent pollution from oil and gas operations, including the prevention of pollution of surface or subsurface water resulting from the drilling of oil and gas wells and the production of oil and gas. In addition to regulating the generation, management and disposal of hazardous oil and gas waste, the Texas Railroad Commission has been delegated authority to regulate underground hydrocarbon storage, saltwater disposal pits and injection wells.

The drilling of oil and gas wells in Texas requires operators to obtain drilling permits, file an organization report and a performance bond or other form of financial security, such as a letter of credit, and obtain a permit to maintain pits to store and dispose of drilling fluids, saltwater and waste as well as other types of pits for other purposes. The issuance of such permits is conditioned upon the Texas Railroad Commission s determination that these pits will not result in waste or pollution of surface or subsurface water.

Other states in which we have an interest in oil and gas properties may impose similar or more stringent regulations than imposed under CERCLA or RCRA.

In re-completing the existing well on the Madisonville Project, we were required to drill a well for injection or disposal of produced waste gas from wells. Injection wells are subject to regulation under the Safe Drinking Water Act (**SDWA**) and the regulations and procedures which have been adopted by the Environmental Protection Agency (**EPA**) under that Act. Generally, enforcement procedures under the SDWA are administered by the EPA unless such authority has been delegated by the EPA to a state which has primary enforcement responsibility based on the EPA s determination that the state has adopted drinking water regulations no less stringent than the national primary drinking water regulations and meets certain other criteria. Underground injection wells not used for the underground injection of natural gas for storage are generally unlawful and subject to penalties under the SWDA unless authorized by:

- permit issued by the EPA or a state having primary enforcement responsibility, or

- rule pursuant to an underground injection control program established by a state or the EPA.

To the extent our pipelines transport natural gas in interstate commerce, the rates, terms and conditions of that transportation service are subject to regulation by the Federal Energy Regulatory Commission, or FERC, pursuant to Section 311 of the Natural Gas Policy Act of 1978, or NGPA, which regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of an interstate natural gas pipeline. Under the Energy Policy Act of 2005, the FERC has authority to impose penalties for violations of the Natural Gas Act, up to $1 million per day for each violation and disgorgement of profits associated with any violation.

The regulatory burden on the natural gas and oil industry increases our cost of doing business. Future developments, such as stricter requirements of environmental or health and safety laws and regulations affecting our business or more stringent interpretations of, or enforcement policies with respect to, such laws and regulations, could adversely affect us. To meet changing permitting and operational standards, we may be required, over time, to make site or operational modifications at our facilities, some of which might be significant and could involve substantial capital expenditures. There can be no assurance that material costs or liabilities will not arise from these or additional environmental matters that may be discovered or otherwise may arise from future requirements of law.   See   Risk Factors   Risks Related to Our Business

Foreign Regulations

We own 12% of C-G Bengara which in turn owns an interest in an oil and gas project located in Indonesia. We have farmed out our interest in this project to a third party who is the operator of this project. In exploring for, drilling and developing this property, this operator will be required to comply with the environmental, conservation, tax and other laws and regulations

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of Indonesia. We own non-operated working interests in oil and gas projects located in Canada. In exploring for, drilling and developing these properties, these operators will be required to comply with the environmental, conservation, tax and other laws and regulations in Canada.

Technology

We participate in projects utilizing economically feasible exploration technology in our exploration and development drilling activities to reduce risks, lower costs, and more efficiently produce oil and gas. We believe that the availability of cost effective 2-D and 3-D seismic data makes its use in exploration and development drilling activities attractive from a risk management perspective in certain areas.

Briefly, through the use of a seismograph, a seismic survey sends pulses of sound from the surface down into the earth, and records the echoes reflected back to the surface. By calculating the speed at which sound travels through the various layers of rock, it is possible to estimate the depth to the reflecting surface. It then becomes possible to infer the structure of rock deep below the earth s surface. We evaluate substantially all of our exploratory prospects using 2-D seismic data. In addition, we own a license as to approximately 12 square miles of 3-D seismic data covering our leasehold and adjacent lands in the Madisonville Project.

The use of seismic technology does not entirely remove the risk of exploration and development drilling of oil and natural gas deposits. It is important to consider the following:

- we may not recognize significant geological features due to errors in interpretation, processing limitations, the presence of certain geological environments that are out of our control or other factors;

- seismic generally becomes less reliable with increasing depth of the geological horizon; and

- the use of this technology may increase our finding cost.

Principal Products

Our principal products are the production of natural gas from properties in which we own an interest. Since our inception, we have realized only limited production of natural gas from the properties in which we own an interest. We have working interests in various undeveloped oil and gas properties. See Properties for a general description of these properties.

During the last three fiscal years, 100% of our revenues have been derived from the sale of natural gas. Substantially all of our natural gas sales have been generated by three producing wells, the Magness #1, Fannin #1 and Mitchell #1 wells, located in the Madisonville Field in East Texas. Natural gas produced by the wells is delivered to a gathering pipeline and transported to a nearby gas treatment plant where it is treated to remove impurities. On December 31, 2008, we purchased this natural gas treatment plant and related gathering pipeline from Madisonville Gas Processing, LP (MGP), an unaffiliated third party. Prior to the plant being purchased, our untreated natural gas was sold at the well head to MGP. Upon completion of the purchase of the treatment plant and gathering pipeline facilities, all future natural gas sales will occur upon delivery to our common carriers. From the plant, the natural gas is transported approximately nine miles to one of two common carrier pipelines from which point it is delivered to the greater Dallas, Texas area. The price received for the natural gas is the Houston Ship Channel price index less certain adjustments for the quality of the gas delivered and gathering and transportation costs.

For financial information regarding our business activities, please see our Financial Statements beginning on page F-1 of this annual report. Substantially all of our revenue is produced from natural gas sales in the Madisonville Field located in East Texas.

Reserves

The volume of production from oil and natural gas properties generally declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our proved reserves will decline as reserves are produced from our properties unless we are able to acquire or develop new reserves.

Acquisition of Producing Properties

We may supplement our exploration efforts with acquisitions of producing oil and gas properties. We may seek to acquire producing properties that are underperforming relative to their potential.

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Patents, Trademarks, Licenses, Franchises and Concessions Held

Permits and licenses are important to our operations, since they allow the search for the extraction of any oil, gas and minerals discovered on the areas covered. See Properties for a general description of the permits and licenses under which we operate. Provided we establish a commercial discovery thereon, the Bengara PSC in Indonesia grants us the right to produce oil and gas from the PSC area until 2027.

Seasonality of Business

Our business is not seasonal.

Working Capital Items

The majority of our current assets are in the form of cash received from the sale of natural gas from our Madisonville Project in Texas, amounts received from issuance of long-term notes, bridge loans, and from the sale of common and preferred stock in private placements. We use this cash to pay for the cost of our operations, service of debt facilities, and other administrative activities. For further information see, Management s Discussion and Analysis of Financial Condition and Results of Operations.

Customers

Substantially all of our revenues to date have been derived from sales to two customers, Luminant Energy Company, and ETC Katy Pipeline, Ltd., of natural gas produced from our Madisonville Project in Texas. We have not committed any forward sales of our natural gas. We contract to sell the gas with spot-market based contracts that vary with market forces. No other customer accounts for in excess of 10% of our revenues. The loss of either of these customers could result in the loss of our revenues, which would have a material adverse effect on our results of operations. See Risk Factors .

Competition

The natural gas and oil industry is intensely competitive and speculative in all of its phases. We encounter competition from other natural gas and oil companies in all areas of our operations. In seeking suitable natural gas and oil properties for acquisition, we compete with other companies operating in our areas of interest, including large natural gas and oil companies and other independent operators, which have greater financial resources and in many instances, have been engaged in the exploration and production business for a much longer time than we have. Many of our competitors also have substantially larger operating staffs than we do. Many of these competitors not only explore for and produce natural gas and oil but also market natural gas and oil and other products on a regional, national or worldwide basis. These competitors may be able to pay more for productive natural gas and oil properties and exploratory prospects and define, evaluate, bid for and purchase a greater number of properties and prospects than us. In addition, these competitors may have a greater ability to continue exploration activities during periods of low market prices. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

The prices of our natural gas production are controlled by market forces. However, competition in the natural gas and oil exploration industry also exists in the form of competition to acquire leases and obtain favorable transportation prices. Our Company is relatively small and may have difficulty acquiring additional acreage and/or projects and may have difficulty arranging for the transportation of our production. We also face competition in obtaining natural gas and oil drilling rigs and in sourcing the manpower to run them and provide related services.

Employees

Currently, we have 20 employees, all of whom are full time. We use the services of independent consultants and contractors to perform various professional services, including geologic, geophysical, petroleum, reservoir & drilling engineering, land, legal, environmental and tax services. On those properties where we are not the operator, we rely on outside operators to drill, produce and market our natural gas and oil.

Available Information

We maintain a website located at http://www.geopetro.com and electronic copies of our annual, quarterly and current reports, and any amendments to those reports, as well as our code of ethics, are available free of charge under the Investor

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Relations link on our website. This information is available on our website, as soon as practicable after such material is filed with, or furnished to, the Securities and Exchange Commission.

Item 1A. ***Risk Factors***

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to our industry and our company could materially impact our future performance and results of operations. We have provided below a list of these risk factors that should be reviewed when considering our securities. These are not all the risks we face and other factors currently considered immaterial or unknown to us may impact our future operations.

Risks Related to Our Business

As of December 31, 2009, we have gross capitalized costs totaling $70 million as proved and unproved oil and gas properties and gas processing plant whereas we have generated revenues of only $40 million since January 1, 2003 and revenues of only $4.1 million during the fiscal year ended December 31, 2009.

Since inception, our activities have been primarily related to acquiring and exploring leasehold interests in oil and natural gas properties in Texas, California, Alaska, Canada, Indonesia and Australia. We incur substantial acquisition and exploration costs and overhead expenses in our operations, and until 2003, excluding minor interest and dividend income, our only significant cash inflows were the recovery of capital invested in projects through sale or other divestitures of interests in oil and gas prospects to industry partners. As a result, we have sustained an accumulated deficit through December 31, 2009 of $38.2 million. Our production activities were commenced in May 2003. Since May 2003, over 98% of our revenue has been generated from natural gas sales derived from wells in the Madisonville Field in Texas. It is possible that in the future we will be unable to continue to generate revenues from our sales of natural gas from our Madisonville Field wells because our proved reserves decline as reserves are produced from the wells. The drilling of exploratory oil and natural gas wells is highly speculative and often unproductive. Our participation in future drilling activities to explore, develop and exploit the properties in which we have an interest, or in which we may acquire interests, may be unsuccessful, may fail to generate positive cash flow, and may not enable us to maintain profitability in the future.

We may be unable to integrate successfully the operations of the Madisonville Gas Treatment Plant with our operations and we may not realize all the anticipated benefits of the Madisonville Gas Treatment Plant.

We formerly contracted with Madisonville Gas Processing, LP, (MGP) which owned and operated gathering pipelines and a dedicated natural gas treatment plant (which we refer to as the Madisonville Gas Treatment Plant), to treat impurities in the natural gas generated by our Madisonville Project. Effective December 31, 2008, we acquired the Madisonville Gas Treatment Plant from MGP through our indirect wholly-owned subsidiary, Madisonville Midstream LLC. We plan to complete the expansion of the Madisonville Gas Treatment Plant s treatment capacity from 18 MMcf/d to 68 MMcf/d. Operations in the additional facilities were suspended by MGP in December 2007 in order to deal with the presence of diamondoids in the gas stream produced from the Rodessa Formation. During March 2009, the Fannin, Magness and Mitchell wells are producing at a combined restricted rate of approximately 6.5 MMcf/d while the Wilson well is shut-in. There can be no assurance that we will be able to accomplish the expansion and achieve a full treatment capacity of 68 MMcf/d.

Even if we are able to successfully complete the expansion of the Madisonville Gas Treatment Plant from 18 MMcf/d to 68 MMcf/d, third parties may seek access to the plant through regulatory proceedings, which could limit our use of the Plant and disrupt our production operations.

Third parties have, and may in the future, seek access to the Madisonville Gas Treatment Plant through regulatory proceedings, which could restrict our access to the Plant, disrupt our production operations and negatively impact our revenues. An example of such a proceeding is the complaint filed by Crimson Exploration Inc. (Crimson) with the Texas Railroad Commission described under Properties Description of the Properties Texas The Madisonville Gas Treatment Plant and Gathering Facilities. On August 9, 2006, the Texas Railroad Commission issued an order requiring MGP to ratably process, take, transport or purchase natural gas produced by Crimson into the Madisonville Gas Treatment Plant. Since Crimson now has the right to have its natural gas treated at the Plant, our ability to treat our own natural gas will be reduced to the extent of Crimson s usage. Crimson is not currently utilizing any of the Plant s capacity. Crimson s usage could increase in the future.

Substantially all of our revenues have been generated from natural gas sales derived from wells in the Madisonville Field, and 100% of our natural gas generated from the Madisonville Field wells is treated at the Madisonville Midstream Gas Treatment Plant, which is 100% indirectly owned by the Company. If our ability to treat natural gas at the Madisonville Midstream Gas Treatment Plant is limited for any reason, including but not limited to increased demands by third parties, our revenues may be adversely affected.

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Substantially all of our current revenues are generated by our interest in the Madisonville Project. Delays or interruptions of the Madisonville Project natural gas drilling and production operations including, but not limited to, events beyond our control or the failure of third parties on which we rely to provide key services, could negatively impact our revenues.

Substantially all of our oil and natural gas revenues for the years ended December 31, 2009 and 2008 were derived from the Madisonville Project. In connection with that project, we have contracted with Gateway Processing Company, (Gateway) which operates a sales pipeline for natural gas.

The failure of Gateway to perform its contractual obligations to us could impose delays or interruptions in our production operations and prevent us from generating revenues. In addition, events which are beyond our control, or that of Gateway, could affect our production operations. Such events include, but are not limited to:

- events referred to as force majeure, such as an act of God, act of a public enemy, war, blockade, public riot, lightning, fire, storm, flood, explosion and any other causes whether of the kind enumerated or otherwise not reasonably within the control of Gateway.

- the inability to secure raw materials or equipment,

- transportation accidents, and

- labor disputes and equipment failures.

We do not own all of the land on which our pipelines and facilities are located, and we are therefore subject to the possibility of not being able to retain necessary land use and associated increased costs.

We have the right to operate our pipelines on land owned by third parties for specified periods of time. Our loss of these rights, through our inability to renew rights-of-way contracts, leases or otherwise, could result in the suspension of our operations, or increased costs related to continuing operations elsewhere, which would have a material adverse effect on our business, results of operations and financial condition.

If third-party pipelines and other facilities interconnected to our natural gas pipelines and processing facilities become partially or fully unavailable to transport natural gas, our revenues could be adversely affected.

We depend upon third party pipelines and other facilities to provide delivery options from the Madisonville Midstream Gas Treatment Plant to our customers. If any of these third party pipelines become unavailable to transport the natural gas produced at the Madisonville Gas Treatment Plant, or if the gas quality specifications for these pipelines or facilities change, we would be required to find alternate means to transport our natural gas out of the Madisonville Gas Treatment Plant, which could increase our costs, reduce the revenues we might obtain from the sale of our natural gas or reduce our ability to process natural gas at the Plant.

In excess of 90% of our revenues to date have been derived from sales by MGP to two customers. The loss of one or both these customers could have a material adverse impact on our oil and gas revenues.

100% of our natural gas sales and revenues for the years ended December 31, 2009 and 2008 were derived from the Madisonville Project. During 2009 and 2008, 100% of our revenues have been derived from sales by MGP to two customers, Luminant Energy Company, LLC, and ETC Katy Pipeline, Ltd. The loss of, or material nonpayment by one of these customers could impact the price we receive for our gas sold due to lessened competition. The loss of, or material nonpayment by, both customers could result in a loss of our revenue. Our customers may be subject to their own operating risks which could increase the risk that they could default on their obligation to us.

Unless we replace our oil and natural gas reserves, our reserves and production will decline.

The volume of production from oil and natural gas properties generally declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our proved reserves will decline as reserves are produced from our properties unless we are able to acquire or develop new reserves. The business of exploring for, developing or acquiring reserves is capital intensive. For example, as of December 31, 2009 we have capitalized costs totaling $70 million as proved and unproved oil and gas properties and gas processing plant. To the extent cash flow from operations is reduced and external sources of capital

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become limited or unavailable, our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves will be impaired. Even if we are able to raise capital to develop or acquire additional properties, no assurance can be given that our future exploitation and development drilling activities will result in the discovery of any reserves.

Our exploration and development drilling activities may not be commercially successful. The drilling of exploratory oil and natural gas wells is expensive, highly speculative and often unproductive.

Exploration for oil and natural gas on unproven prospects is expensive, highly speculative and involves a high degree of risk, including the risk that no commercially productive oil or natural gas reservoirs will be encountered. Reserves are dependent on our ability to successfully complete drilling activity on proven prospects.

The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors, including:

- unexpected drilling conditions, pressure or irregularities in formations;

- subsurface conditions or formations encountered during the drilling of wells, whether natural or mechanical, including but not limited to blowout, igneous rock, salt, saltwater flow, loss of circulation, loss of hole, abnormal pressures, or any other impenetrable substance or adverse condition, which renders further drilling of a well impossible or impractical.

- equipment failures or accidents, adverse weather conditions;

- compliance with governmental requirements; and

- shortages or delays in the availability of drilling rigs, the delivery of equipment, and availability of qualified manpower.

Our evaluations of the oil and gas prospects of our properties may be wrong.

With the exception of the Madisonville Project, the properties in which we have an interest are prospects in which the presence of oil and natural gas reserves in commercial quantities has not been established. Any decision to engage in exploratory drilling or other activities on any of these properties will be dependent in part on the evaluation of data compiled by petroleum engineers and geologists and obtained through geophysical testing and geological analysis.

Reservoir engineering, geophysics and geology are not exact sciences and the results of studies and tests used to make such evaluations are sometimes inconclusive or subject to varying interpretations. As such, there is no certain way to know in advance whether any of our prospects will yield oil and natural gas in commercial quantities. Further, it is possible that we will participate in the drilling of more dry holes than productive wells or that all or substantially all of the wells drilled will be dry holes. The drilling of dry holes on prospects in which we have an interest could adversely affect their values and our decision to undertake further exploration and development drilling of such prospects. It is not certain or predictable whether, and no assurance can be made that, the wells drilled on the properties in which we have an interest will be productive or, if productive, that we will recover all or any part of our investment in the properties. In sum, our participation in future drilling activities may not be successful and, if unsuccessful, such failure will negatively impact our revenues and have a material adverse effect on our results of operations and financial condition. Our natural gas sales and revenues were $4,077,355 and $6,152,542 for the years ended December 31, 2009 and 2008, respectively. Future revenues could decline from those levels if our future drilling efforts are not successful. Furthermore, as of December 31, 2009 we have net capitalized costs totaling $31 million as proved and unproved oil and gas properties and gas processing plant. Should our future drilling activities be unsuccessful, we may then be required to record an impairment charge equal to a portion of, or all, of the capitalized costs resulting in an immediate adverse impact on our results of operations and financial position.

Our business may be harmed by failures of third party operators on which we rely.

Our ability to manage and mitigate the various risks associated with certain of our exploration and operations in Alberta, Canada, and Indonesia is limited since we rely on third parties to operate our projects. We are a non-operating interest owner in our Canadian and Indonesian properties. With respect to our interests in Canada and Indonesia, we have entered into agreements with third party operators for the conduct and supervision of drilling, completion and production operations. In the event that commercial quantities of oil and natural gas are discovered on one of our properties, the success of the oil and natural gas

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operations on that property depends in large measure on whether the operator of the property properly performs its obligations. The failure of such operators and their contractors to perform their services in a proper manner could result in materially adverse consequences to the owners of interests in that particular property, including us.

Our percentage share of oil and gas revenues from our Indonesian property is diminished by the terms of our production sharing contract in the Bengara Block.

C-G Bengara owns 100% of the underlying rights to explore for and produce oil and natural gas within the Bengara Block. We have a 12% interest in C-G Bengara. C-G Bengara is subject to a production sharing contract, which means generally that C-G Bengara is entitled to receive, from production proceeds, 100% of expenditures in the block as cost recovery. Once these costs are recovered, C-G Bengara s production share will be reduced to approximately 26.7% of oil produced and 62.5% of all natural gas produced. We are entitled to 12% of C-G Bengara s reduced share of any such production. See the discussion under Properties- Indonesia Terms of Participation in the Bengara Block for more information concerning the production sharing contract.

Drilling and completion equipment, services, supplies and personnel are scarce and may not be available when needed, which could significantly disrupt or delay our operations.

From time to time, there has been a general shortage of drilling rigs, equipment, supplies and oilfield services in North America and Indonesia. In addition, the costs and delivery times of rigs, equipment and supplies have risen when short supply of equipment existed in the past. There can be no assurance that sufficient drilling and completion equipment, services and supplies will be available when needed. Shortages could delay our proposed exploration, development drilling, and sales activities, which could have a material adverse effect on our results of operations. Our natural gas sales were $4.08 million for the year ended December 31, 2009. Future revenues could decline from those levels if we experience delays in our proposed exploration, development drilling, and sales activities. The demand for, and wage rates of, qualified rig crews have risen in the drilling industry due to the increasing number of active rigs in service. If the demand for qualified rig crews continues to rise in the drilling industry, then the oil and gas industry may experience shortages of qualified personnel to operate drilling rigs. This could delay our drilling operations and adversely affect our financial condition and results of operations.

Our working interest in properties, and our ability to realize any profits from such properties, will be diminished to the extent that we enter into farmout arrangements with unaffiliated third parties.

We have previously entered into, and may in the future enter into, farmout arrangements with third parties willing to drill natural gas and oil wells on leaseholds in which we originally acquired working interests, in exchange for our assignment of part or all of our leasehold interests. As a consequence of these arrangements, our retained interests in properties which are subject to farmout arrangements have been or may be diminished. Our opportunity to realize revenues and profits from properties which are successfully developed under farmout arrangements will be diminished to the extent of our reduced interests.

Competition with other oil and natural gas exploration and development drilling companies for viable oil and natural gas properties may limit our success.

It is likely that in seeking future property acquisitions, we will compete with companies which have substantially greater financial and management resources. Our competition comes primarily from three sources:

(a) those competitors that are seeking oil and gas fields for expansion, further drilling, or increased production through improved engineering techniques;

(b) income-seeking entities purchasing a predictable stream of earnings based upon historic production from fields being acquired; and

(c) junior companies seeking exploration opportunities in unknown, unproven territories.

Our competitors may be able to pay more for productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to acquire additional properties in the future will depend upon our ability to conduct efficient operations, evaluate and select suitable properties, implement advanced technologies and consummate transactions in a highly competitive environment.

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Estimates of oil and natural gas reserves are inherently imprecise. Any material inaccuracies in these reserve estimates or underlying assumptions will affect materially the quantities and present value of our reserves.

Estimates of proved oil and natural gas reserves and the future net cash flows attributable to those reserves are prepared by independent petroleum engineers and geologists. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and cash flows attributable to such reserves, including factors beyond our control and that of our engineers. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Different reserve engineers may make different estimates of reserves and cash flows based on the same available data. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding future oil and natural gas prices and expenditures for future development drilling and exploration activities, and of engineering and geological interpretation and judgment. Additionally, reserves and future cash flows may be subject to material downward or upward revisions, based upon production history, development drilling and exploration activities and prices of oil and natural gas. Actual future production, revenue, taxes, development drilling expenditures, operating expenses, underlying information, quantities of recoverable reserves and the value of cash flows from such reserves may vary significantly from the assumptions and underlying information set forth herein.

Competitive pressures may force us to implement new technologies at substantial cost and our limited financial resources may limit our ability to implement such technologies at the same rate as our competitors.

The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we do. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at all. One or more of the technologies currently utilized by us or implemented in the future may become obsolete.

We will require additional capital to fund our future activities. Our ability to pursue our business plan may be restricted by our access to additional financing.

Until such time as the properties in which we own interests are generating sufficient cash flow to fund planned capital expenditures, we will be required to raise additional capital through the issuance of additional securities or otherwise sell or farmout interests in our oil and natural gas properties to third parties. If and when the properties in which we own interests become productive and have adequate reserves, we may borrow funds to finance our future oil and natural gas operations and exploratory and development drilling activities. We may not be able to raise additional funds in the future from any source or, if such additional funds are made available to us, we may not be able to obtain such additional financing on terms acceptable to us. To the extent such funds are not available from any of those sources, our operations and activities will be limited to those operations and activities we can afford with the funds then available to us. Our larger competitors, by reason of their size and relative financial strength, may be more easily able to access capital markets than us.

The volatility in crude oil and natural gas prices could adversely affect our financial results and ability to raise additional capital.

Our revenues, cash flows and profitability are substantially dependent on prevailing prices for both oil and natural gas. Decreases in natural gas prices will decrease revenues and cash flows from the Madisonville Project and our other producing properties, if any, and decreases in oil and natural gas prices could deter potential investors from investing in our company and generally impede our ability to raise additional financing to fund our exploration and development drilling activities. Historically, oil and natural gas prices and markets have been volatile, and they are likely to continue to be volatile in the future. Prices for oil and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of, and demand for, oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include, but are not limited to, political conditions in the Middle East and other regions, internal and political decisions of OPEC and other oil and natural gas producing nations to decrease or increase production of crude oil, domestic and foreign supplies of oil and natural gas, consumer demand, weather conditions, domestic and foreign government regulations and taxation, transportation costs, the price and availability of alternative fuels, the impact of energy conservation efforts and overall economic conditions.

Risks associated with recent economic trends have adversely affected, and could further adversely affect our financial performance.

As widely reported, the global financial markets have been experiencing extreme disruption in the past year, including severely diminished liquidity and credit availability. Concurrently, we have experienced a global recession. We believe these conditions have adversely impacted our financial position as of December 31, 2009 and our liquidity for the twelve months ended December 31, 2009. Our financial condition and performance could be further negatively impacted if either of these conditions continues to exist for a sustained period of time, or if there is further deterioration in financial markets and major

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economies. We are unable to predict the likely duration and severity of the current disruption in financial markets and adverse economic conditions in the U.S. and abroad.

We are subject to a number of operational risks beyond our control against which we may not have, or be able to obtain insurance.

Our operations are subject to the many risks and hazards incident to exploring and drilling for, and producing and transporting, oil and natural gas, including among other risks:

- blowouts, fires, craterings, pollution and equipment failures that may result in damage to or destruction of wells, pipelines, producing formations, production facilities and equipment;

- damage to pipelines, facilities and properties caused by hurricanes, tornados, floods and other natural disasters

- personal injuries or death due to accidents, human error or acts of God;

- unavailability of materials and equipment to drill and complete or re-complete wells; unfavorable weather conditions; engineering and construction delays;

- fluctuations in product markets and prices; proximity and capacity of pipeline, and trucking or termination facilities to our oil and natural gas reserves; hazards resulting from unusual or unexpected geological or environmental conditions; environmental regulations and requirements;

- accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids into the environment, remediation and clean-up costs; and

- political instability and civil unrest, insurrections or disruptions in foreign countries in which some of our interests are located.

If one or more of these events occurs, we could incur substantial liabilities to third parties or governmental entities, the payment of which could have a material adverse effect on our financial condition and results of operations, or we could lose properties in which we have invested significant sums (totaling $70 million) which are capitalized as proved and unproved oil and gas properties and gas processing plant as of December 31, 2009.

A loss not covered by insurance could result in substantial expenses to us.

We do not insure fully against all business risks either because such insurance is not available or because premium costs are prohibitive. We are not insured against all environmental accidents that might occur which may include toxic tort claims. If a significant accident or event occurs that is not fully insured, if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, or if we fail to rebuild facilities damaged by such accidents or events, our operations and financial condition could be adversely affected. In addition, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially, and could escalate further. For example, following Hurricanes Katrina and Rita, insurance premiums, deductibles and co-insurance requirements increased substantially, and terms generally are less favorable than terms that could be obtained prior to such hurricanes. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. A loss not fully covered by insurance could result in expenses to us and could have a material adverse effect on our financial position and results of operations. Uninsured losses in excess of $1.0 million would be materially adverse to our financial position and results of operations.

We are subject to extensive government regulations that can change from time to time, compliance with which are costly and could negatively impact our production, operations and financial results.

The oil and gas industry is subject to extensive government regulations in the countries in which we operate. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, unitization and pooling of properties and taxation. Historically, our costs of complying with these regulations have not exceeded $100,000 per year. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity in order to conserve supplies of oil and natural gas. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted. Legal requirements are frequently changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or

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their effects on our operations. Future laws, or existing laws or regulations, as currently interpreted or reinterpreted or changed in the future, could result in increased operating costs, fines and liabilities, in amounts which are unknown at this time, any of which could materially adversely affect our results of operations and financial condition.

Our industry is subject to extensive environmental regulation that may limit our operations and negatively impact our production.

Extensive national, state, provincial and local environmental laws and regulations in the United States and foreign jurisdictions affect nearly all of our operations. Environmental laws to which we are subject in the U.S. include, but are not limited to, (1) the Clean Air Act and comparable state laws that impose obligations related to air emissions, (2) the Resource Conservation and Recovery Act of 1976 (RCRA), and comparable state laws that impose requirements for the handling, storage, treatment or disposal of solid and hazardous waste from our facilities, (3) the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which our hazardous substances have been transported for disposal, and (4) the Clean Water Act, and comparable state laws that regulate discharges of wastewater from our facilities to state and federal waters. Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations or imposing additional compliance requirements on such operations. Certain environmental laws, including CERCLA and analogous state laws, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

Environmental legislation may require that we:

- acquire permits before commencing drilling;

- restrict spills, releases or emissions of various substances produced in association with our operations;

- limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas;

- take reclamation measures to prevent pollution from former operations;

- take remedial measures to mitigate pollution from former operations, such as plugging abandoned wells and remedying contaminated soil and groundwater;

- take remedial measures with respect to property designated as a contaminated site.

There is inherent risk of incurring environmental costs and liabilities in connection with our operations due to our handling of natural gas and other petroleum products, air emissions and water discharges related to our operations, and historical industry operations and waste disposal practices. The costs of any of these liabilities are presently unknown but could be significant. We may not be able to recover all or any of these costs from insurance.

We are not presently aware of any environmental liabilities or able to predict the ultimate cost of liabilities not yet recognized. We have not established a separate reserve fund for the purpose of funding any possible future environmental liability. As a result, we may not be able to satisfy these obligations, if they occur. Any such costs incurred will be funded out of our cash flow from operations. If we are unable to fully fund the cost of remedying an environmental obligation, we might be required to suspend operations or enter into interim compliance measures pending satisfaction of the liability, which could have an adverse affect on our financial condition and results of operations. We have recorded an asset requirement obligation in connection with the estimated future costs to plug certain wells at our Madisonville Project in Texas upon abandonment totaling approximately $65,000 as of December 31, 2009. See Business Regulation.

The effects of future environmental legislation on our business is unknown but could be substantial.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. Changes in, or enforcement of, environmental laws may result in a curtailment of our production activities, or a material increase in the costs of production, development drilling or exploration, any of which could have a material adverse effect on our financial condition and results of operations or prospects. In addition, many countries, as well as several states in the United States have agreed to regulate emissions of greenhouse

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gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning natural gas, are greenhouse gases. Regulation of greenhouse gases could adversely impact some of our operations and demand for products in the future. See Business Regulations.

Potential regulations regarding climate change could alter the way we conduct our business.

Governments around the world are beginning to address climate change matters. This may result in new environmental regulations that may unfavorably impact us, our suppliers and our customers. The cost of meeting these requirements may have an adverse impact on our financial condition, results of operations and cash flows.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Energy Policy Act of 2005, the Federal Energy Regulatory Commission, or FERC, has authority to impose penalties for violations of the Natural Gas Act, up to $1 million per day for each violation and disgorgement of profits associated with any violation. FERC has recently proposed and adopted regulations that may subject our facilities to reporting and posting requirements. Additional rules and legislation pertaining to these and other matters may be considered or adopted by FERC from time to time. Failure to comply with FERC regulations could subject us to civil penalties.

We may incur significant costs and liabilities as a result of pipeline integrity management program testing and any related pipeline repair or preventative or remedial measures.

The United States Department of Transportation, or DOT, has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located where a leak or rupture could do the most harm in high consequence areas. The regulations require operators to:

- Perform ongoing assessments of pipeline integrity;
- Indentify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- Improve data collection, integration and analysis;

- Repair and remediate the pipeline as necessary; and
- Implement preventive and mitigating actions.

Political and/or economic conditions in Indonesia, Canada or the United States could change in manners that negatively affect our operations and prospects in those countries.

Our business activities in Indonesia, Canada and the United States are subject to political and economic risks, including: loss of revenue, property and equipment as a result of unforeseen events like expropriation, nationalization, war, terrorist attacks and insurrection; increases in import, export and transportation regulations and tariffs, taxes and governmental royalties; renegotiation of contracts with governmental entities; changes in laws and policies governing operations of foreign-based companies; exchange controls, currency fluctuations and other uncertainties arising out of foreign government sovereignty over international operations; laws and policies affecting foreign trade, taxation and investment; and the possibility of being subject to the exclusive jurisdiction of foreign courts in connection with legal disputes and the possible inability to subject foreign persons to the jurisdiction of courts in the United States.

Terrorist attacks could have an adverse effect on our oil and natural gas operations, especially overseas.

To date, our operations have not been disrupted by terrorist activity. It is uncertain how terrorist activity will affect us in the future, or what steps, if any, the Indonesian, Canadian or American government may take in response to terrorist activities. The attack on the New York World Trade Center in 2001 and the subsequent wars in Afghanistan and Iraq have increased the likelihood that U.S. citizens and U.S. owned interests may be targeted by terrorist groups operating both in the United States and in foreign countries, especially in Indonesia.

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We could lose our entire Production Sharing Contract (PSC), if BP Migas ascertains we have not discovered commercially producible hydrocarbons.

It is possible that BP Migas could terminate our entire Production Sharing Contract (PSC) if it is determined that the hydrocarbons we have discovered are not in commercially producible quantities. Our Indonesian PSC requires us and our partners to submit to and receive approval from BP Migas for a Plan of Development by specified dates in order to maintain our oil and natural gas rights. See Properties Description of the Properties Indonesia. If we do not establish commerciality and receive an approved Plan of Development for the PSC, or successfully renegotiate the terms, all or part of our contract may be terminated. If this contract is terminated, we would also lose all of our investment in that overseas prospect. If we forfeit our interest in the contract area, it will be necessary to record an impairment write-down equal to the net capitalized costs recorded for the area forfeited. This could have a material adverse impact on our financial condition and results of future operations in future periods. If approval of a Plan of Development is not obtained and if further deferrals of such obligations are not secured, we will need to record an impairment charge equal to the amount of costs capitalized which were approximately $584,000 as of December 31, 2009, and we may lose all of our rights in the Bengara Block.

We may not be able to sell our natural gas production in Indonesia, limiting our ability to obtain a return on our investment there.

Our Indonesian operations lack a local market for natural gas, and if we produce natural gas in Indonesia, it will most likely have to be transported to an area where there is a demand. If no market for natural gas develops locally, we may incur costs for transportation. If we are not able to sell our natural gas production at a commercially acceptable price or at all, we may not be able to obtain a return on our investment in our Indonesian property.

We could lose our ownership interests in our properties due to a title defect of which we are not presently aware.

As is customary in the oil and gas industry, only a perfunctory title examination, if any, is conducted at the time properties believed to be suitable for drilling operations are first acquired. Before starting drilling operations, a more thorough title examination is usually conducted and curative work is performed on known significant title defects. We typically depend upon title opinions prepared at the request of the operator of the property to be drilled. The existence of a title defect on one or more of the properties in which we have an interest could render it worthless and could result in a large expense to our business. Industry standard forms of operating agreements usually provide that the operator of an oil and natural gas property is not to be monetarily liable for loss or impairment of title. The operating agreements to which we are a party provide that, in the event of a monetary loss arising from title failure, the loss shall be borne by all parties in proportion to their interest owned.

Our acquisition activities are subject to uncertainties and may not be successful nor provide a return to us on our investments.

We have grown primarily through acquisitions and intend to continue acquiring undeveloped oil and gas properties. Although we perform a review of the properties proposed to be acquired, such reviews are subject to uncertainties. It generally is not feasible to review in detail every individual property involved in an acquisition. Ordinarily, management review efforts are focused on the higher-valued properties; however, even a detailed review of all properties and records may not reveal existing or potential problems; nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections are not always performed on every well, and potential problems, such as mechanical integrity of equipment and environmental conditions that may require significant remedial expenditures, are not necessarily observable even when an inspection is undertaken.

We are dependent upon our key officers and employees and our inability to retain and attract key personnel could significantly hinder our growth strategy and cause our business to fail.

While no assurances can be given that our current management resources will enable us to succeed as planned, a loss of one or more of our current directors, officers or key employees could severely and negatively impact our operations and delay or preclude us from achieving our business objectives. Stuart Doshi and David Creel, two members of our senior management team, have a combined experience of approximately 80 years in the oil and gas industry. We could suffer the loss of key individuals for one reason or another at any time in the future. There is no guarantee that we could attract or locate other individuals with similar skills or experience to carry out our business objectives. We maintain key man insurance with respect to our Chief Executive Officer, Stuart Doshi.

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Some of our directors may become subject to conflicts of interest which could impair their abilities to act in our best interest.

Nick DeMare, one of our directors, is a director, officer and/or significant shareholder of other natural resource companies and David Anderson, another one of our directors, is a director and officer of Dundee Securities Corporation, an investment banking firm that was the lead underwriter of our public offering of common stock in Canada and concurrent previous private placement of common shares with qualified institutional buyers in the U.S. Their association with these other companies in the oil and gas business may give rise to conflicts of interest from time to time. For example, they could be presented with business opportunities in their capacities as our directors, which they could, in turn, offer to the other companies for whom they also serve as directors, rather than to us, whose interests might be competitive with ours. Our directors are required by law to act honestly and in good faith with a view to our best interests and to disclose any interest which they may have in any project or opportunity to us; however, their interests in the other companies may affect their judgment and cause such directors to act in a manner that is not necessarily in our best interests.

Our directors and officers hold significant positions in our shares and their interests may not always be aligned with those of our other shareholders.

As of December 31, 2009 our directors and officers beneficially own approximately 18.7% of our outstanding common stock. This shareholding level will allow the directors, officers and certain beneficial owners to have a significant degree of influence on matters that are required to be approved by shareholders, including the election of directors and the approval of significant transactions. The short-term interests of our directors, officers and certain beneficial owners may not always be aligned with the long-term interests of our public shareholders, and vice versa. Because our directors, officers and certain beneficial owners have a significant degree of influence on matters that are required to be approved by our shareholders, they could influence the approval of transactions.

Our failure to manage internal or acquisition-based growth may cause operational difficulties and negatively affect our financial performance.

We expect to experience internal and/or acquisition-based growth, which may bring many challenges. Growth in the number of employees, sales and operations will place additional pressure on already limited resources and infrastructure. No assurances can be given that we will be able to effectively manage this or future growth. Our growth may place a significant strain on our managerial, operational, financial and other resources. Our success will depend upon our ability to manage our growth effectively which will require that we continue to implement and improve our operational, administrative and financial and accounting systems and controls and continue to expand, train and manage our employee base. Our systems, procedures and controls may not be adequate to support our operations and our management may not be able to achieve the rapid execution necessary to exploit the market for our business model. If we are unable to manage internal and/or acquisition-based growth effectively, our business, results of operations and financial condition will be materially adversely affected.

Risks associated with recent economic trends could adversely affect our financial performance.

In 2010 we will need to raise capital. Due to the tight credit markets and prolonged downturn in the stock market, funds may not be available, or may be available only on unfavorable terms. Due to the decrease in our stock price, we may need to sell more shares to raise the same amount of money than we would have in the past, resulting in greater dilution to existing shareholders than would be the case if our stock price was higher and this trend could continue. We have scheduled exploratory and development well drilling and workover activity during 2010 and future periods on our proved and unproved properties. It is anticipated that these activities together with others that we may undertake will impose financial requirements which will exceed our existing working capital. We may raise additional equity and/or debt capital, and we may farmout certain of our projects to finance our continued participation in planned activities; however, if additional financing is not available, we may be compelled to reduce the scope of our business activities. If we are unable to fund planned expenditures, it may be necessary to:

- farm-out our interest in proposed wells;
- sell a portion of our interest in prospects and use the sale proceeds to fund our participation for a lesser interest;
- forfeit our interest in wells that we propose to drill; and
- reduce general and administrative expenses.

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Risks Related to Our Common Stock

The shareholding position of holders of our common stock could be diluted by future issuances and conversions of other securities.

If our options and warrants are exercised for common shares, holders of our common stock will experience immediate and, depending on the magnitude of the exercises, substantial dilution. As of March 31, 2010, 34,284,646 shares of our common stock are outstanding, 7,523,000 shares of our Series B Preferred stock are outstanding, 1,561,547 shares of our common stock are issuable upon exercise of warrants and 2,004,000 shares of our common stock are issuable upon exercise of options and 7,523,000 shares of our common stock are issuable upon conversion of the series B Preferred Stock.

Investors may be subject to further dilution if we sell additional common shares or issue additional common shares in connection with future financings. If a significant number of our common shares are sold in the public market, the market price of our common shares could be depressed. This could hamper our ability to raise capital by issuing additional equity securities.

Our results may be affected by fluctuations in currency exchange rates.

Our financial statements are reported in U.S. dollars and all of our revenue, and most of our operating costs, are currently denominated in U.S. dollars; however, we have operations outside the United States and we plan to expend money in Indonesia and Canada, where our operating costs will be denominated in local currencies. Fluctuations in exchange rates may increase our relative cost of operating in these countries, and may therefore have a negative effect on our financial results.

Non- U.S. holders of our common shares may be subject to U.S. federal income tax on the sale of our common shares and purchasers may have IRS withholding requirements

Since we believe that we are a United States real property holding corporation, gain recognized by a non-U.S. holder on the sale of our common shares will be subject to U.S. federal income tax at normal graduated rates, and a purchaser will be required to withhold for the benefit of the IRS 10% of the purchase price, unless certain trading requirements are met. There is an exemption from U.S. federal income tax for non-U.S. holders of 5% or less of our common shares (and therefore no tax withholding requirements) if our common shares are regularly traded on an established securities market. In the event that 100 or fewer persons own 50% or more of our common shares (which had been, may now be and may continue to be, the case), temporary Treasury Regulations provide that our common shares will be regularly traded on an established securities market for a calendar quarter if the established securities market is located in the United States and our common shares are regularly quoted by more than one broker or dealer making a market in our common shares; our common shares are currently listed on the NYSE Amex (which constitutes an established United States securities market for this purpose) and are being regularly quoted. There can be no assurance, however, that our common shares will continue to be regularly traded on an established securities market for this purpose in any particular calendar quarter so as to avoid U.S. federal income tax on the sale of our common shares by non-U.S. holders of 5% or less of our common shares and the withholding requirement on the purchaser.

At such time that it is no longer the case that 100 or fewer persons own 50% or more of our common shares, under temporary Treasury Regulations, our common shares would also be regularly traded on an established securities market for a calendar quarter if: (a) our common shares trade, other than in de minimis quantities, on at least 15 days during the calendar quarter; (b) the aggregate number of our common shares traded during the calendar quarter is at least 7.5% of the average number of our common shares outstanding during such calendar quarter (reduced to 2.5% if there are 2,500 or more record shareholders); and (c) in the event that our common shares are traded on an established securities market located outside the United States, the common shares are registered under Sec. 12 of the Securities Exchange Act of 1934. See Material Income Tax Consequences Dispositions of Common Shares for a more detailed discussion.

There is a limited public market for our common shares, and the ability of our shareholders to dispose of their common shares may be limited.

Our common shares have been trading on the NYSE Amex (formerly the American Stock Exchange) since February 15, 2007. We cannot foresee the degree of liquidity that will be associated with our common shares. A holder of our common shares may not be able to liquidate his, her or its investment in a short time period or at the market prices that currently exist at the time the holder decides to sell. The purchase and sale of relatively small common share positions may result in disproportionately large increases or decreases in the price of our common shares. A trade involving a large number of common shares could have an exaggerated effect on the reported market price of our common shares.

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Our stock price may fluctuate significantly.

The stock market in general and the market for natural gas and oil exploration companies have experienced price and volume fluctuations that are often unrelated or disproportionate to the operating results or asset values of companies. These broad market and industry factors may seriously impact the market price and trading volume of our common shares regardless of our actual operating performance. The market price of our common stock could also fluctuate significantly as a result of:

- actual or anticipated quarterly variations in our operating results and our reserve estimates;
- changes in expectations as to our future financial performance or changes in financial estimates, if any, of public market analysts;
- announcements relating to our business or the business of our competitors;
- conditions generally affecting the oil and natural gas industry, including changes in oil and natural gas prices;
- speculation in the press or investment community;
- general market and economic conditions;
- the success of our operating strategy; and
- the operating and stock price performance of other comparable companies.

The sale of large numbers of our common stock may depress the market price of our common stock.

The sale of a substantial number of shares of our common stock in the public market, or the perception that substantial sales may occur, could cause the market price of our common stock to decrease. Substantially all of the shares of our common stock are freely transferable or will be transferable in compliance with restrictions under the Securities Act of 1933, as amended. In 2010, we will need to raise additional working capital and investors may be subject to further dilution if we sell additional common shares or issue additional common shares in connection with future financings. If a significant number of our common shares are sold in the public market, the market price of our common shares could be depressed. This could hamper our ability to raise capital by issuing additional equity securities.

We will continue to incur significant expenses as a result of being a public company, which may negatively impact our financial performance.

We have incurred and will continue to incur significant legal, accounting, insurance and other expenses as a result of being a public company. The Sarbanes-Oxley Act of 2002, as well as related rules implemented by the Securities and Exchange Commission, or SEC, and the NYSE Amex, have required changes in corporate governance practices of public companies. Compliance with these laws, rules and regulations has increased our expenses, including our legal and accounting costs, and made some activities more time-consuming and costly. As a result, it may be more difficult for us to attract and retain qualified persons to serve on our board of directors or as officers. Furthermore, any additional increases in legal, accounting, insurance and certain other expenses that we may experience in the future could negatively impact our financial performance and have a material adverse effect on our results of operations and financial condition**.**

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Our principal executive office consists of 2,956 square feet and is located at One Maritime Plaza, Suite 700, San Francisco, CA 94111 until April 30, 2010. The new principal executive office contains 4,201 square feet and is located at 150 California Street, Suite 600, San Francisco, CA 94111 effective May 1, 2010 thru April 30, 2017.

Description of the Properties

Our current oil and natural gas exploration, appraisal and development drilling activities are focused in four distinct project areas as follows:

- **United States Texas** (East Texas and onshore South Texas regions), **Alaska** (onshore Cook Inlet area) and **California** (onshore San Joaquin basin);

- **Canada Alberta** (central Alberta basin);

- **Indonesia** onshore and offshore East Kalimantan Province; and

- **Australia** onshore in two permit areas located in the South Perth basin.

We do not fully insure against all business risks either because such insurance is not available or because premium costs are prohibitive. This is a common practice in the oil and gas industry. We believe our property is adequately insured in view of the nature of our operations and industry practices in this regard.

Texas

Madisonville Project, Madison County, East Texas

We own and operate the interest in the Madisonville Project in Madison County, Texas. We own working interests in approximately 4,557 gross and net acres of leases in the Rodessa Formation interval, as well as approximately 4,447 gross and net acres of leases as to depths below the Rodessa Formation interval. We also own a license as to 12.5 square miles of 3-D seismic data over the Madisonville Field.

The Madisonville Field, located approximately 100 miles north of Houston, has produced oil and natural gas from four different horizons above the Rodessa Formation for over 50 years. The field was discovered in 1945 with the Boring No. 1 well, which was drilled to the Rodessa Formation. The well blew out at an uncontrolled rate for three days during a test; however, due to hydrogen sulphide, carbon dioxide and nitrogen in the Rodessa Formation natural gas, the gas reserves were never developed. Over 125 wells were drilled in the Madisonville Field to shallower intervals above the Rodessa Formation. In 1994, nearly 50 years after the initial discovery, United Meridian Corporation (**UMC**) drilled the Magness Well as the first follow-up well into the Rodessa Formation to the Boring No. 1 well. The Magness Well had 139 feet of net pay but the natural gas was found to contain 28% impurities.

UMC previously production tested the Magness Well in 1994 through perforations in the lower most ten feet of the indicated Rodessa Formation pay interval. The well tested at a rate of 12 MMcf/d from this limited interval on a 22/64ths inch choke with flowing wellhead pressures increasing from 3,915 to 3,919 pounds per square inch. In 2001, we re-entered and recompleted the Magness Well. A total of 139 feet of interval has been perforated in the Rodessa Formation at approximately 12,000 feet of depth for this well. The well was production tested over a 12-day period in 2001 on various choke sizes with flowing rates ranging up to approximately 20.8 MMcf/d. We own a 100% working interest (75.1333% net revenue interest) in the Magness Well located in the surrounding production unit consisting of 684 gross and 629 net acres. The Magness Well commenced production in May of 2003.

The first development well, the Fannin Well, was drilled and completed in 2004. We own a 100% working interest (69.9162% net revenue interest) in the Fannin Well located in the surrounding production unit consisting of 704 gross and net acres. A total of 146 feet of indicated pay was perforated in the well and a flow test of the well was completed in December 2004 from the Rodessa Formation at rates of up to 25.7 MMcf/d. We commenced production from the Fannin Well in early 2006.

The Madisonville Field is a geologic feature encompassing approximately 5,800 acres at the Rodessa limestone at about 11,800 feet of depth. A 3-D seismic program shot in early 1998 confirmed the size of the structure and slightly increased its size over earlier interpretations.

Our working interest covers the Rodessa Formation at approximately 12,000 feet of depth. The Rodessa reserves are being developed through the recompletion of the Magness Well and the drilling of additional proved undeveloped locations. Production began in May 2003 and stabilized at a rate of 18 MMcf/d of raw gas from the Magness Well. In 2006, we drilled the Wilson and Mitchell wells. We own a 100% working interest (70% net revenue interest) in the Wilson and Mitchell wells. The Magness, Fannin and Mitchell wells are currently producing at a combined restricted rate of approximately 6.5 MMcf/d while the Wilson well is shut-in. Current net sales production is approximately 3.0 MMcf/d. In addition, we own a working interest in certain leases and farmout rights which cover depths below the Rodessa Formation.

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The hydrogen sulphide, carbon dioxide and nitrogen combined comprise about 28% of the gas content. The untreated natural gas is delivered to the Madisonville Midstream Gas Treatment Plant where all the natural gas impurities are removed before delivery to the sales pipeline. As a result of the costs to treat the natural gas, we receive a net price that is substantially lower than we would otherwise receive if the gas did not contain the 28% of impurities. In addition, the high concentrations of hydrogen sulphide and carbon dioxide result in higher capital and operating costs for our wells. For example, the hydrogen sulphide and carbon dioxide are corrosive to the wellbores. This means we have to utilize higher grade specification well tubing and casing which is more expensive than what we would utilize absent the impurities. In addition, we continuously treat the wellbores with chemicals designed to inhibit the corrosive effects of the impurities. We also maintain field personnel at or near the wellsites who monitor the wells on a twenty four hour basis and equip the wellsites with extensive safety equipment systems due to the toxic properties of the hydrogen sulphide and carbon dioxide. These factors and others result in higher capital and operating costs for our wells in the Madisonville Project.

The Madisonville Midstream Gas Treatment Plant and Gathering Facilities

In order to produce the proved gas reserves from the Rodessa Formation, we developed an onsite plan to treat and remove impurities from the Madisonville Project natural gas in order to meet pipeline-quality specifications. On June 15, 2001, we, through our subsidiary Redwood LP, entered into an agreement, which agreement was subsequently amended and restated, together with certain related agreements (collectively, the **Hanover Agreement**), with Hanover Compression Limited Partnership pursuant to which Hanover committed to fund, construct and operate a dedicated natural gas treatment plant to process our Rodessa Formation natural gas. The Hanover Agreement also provided for the installation by Gateway of field gathering pipelines and an approximately nine-mile sales pipeline with an estimated capacity of approximately 70 MMcf/d to transport the Madisonville Field natural gas to a major pipeline. By April of 2003, the construction and installation of Hanover s natural gas treatment plant and Gateway s associated pipeline and gathering facilities were completed. Gas production from the Magness Well commenced in May 2003. We received the first revenues from the sale of natural gas from the Madisonville Project in July 2003.

On July 25, 2005, MGP purchased the natural gas treatment plant from Hanover and purchased the gathering pipelines upstream of the gas treatment plant from Gateway. Concurrent with MGP s purchase of the gas treatment plant and gathering pipelines, we, through our subsidiary Redwood LP, Gateway and MGP terminated the Hanover Agreement and entered into a new agreement, (the **MGP Agreement**), to treat and transport our gas production from the Madisonville Project. As a result of the MGP Agreement, MGP committed to install and make operational additional treating facilities capable of treating 50 MMcf/d, which combined with the capacity of the current in-service treating facilities would represent a total treating capacity of 68 MMcf/d for the Madisonville treatment plant. The MGP Agreement provided that the newly installed gas treatment facilities would be electrically driven. Currently, the existing in-service treatment plant utilizes some of the natural gas produced and delivered from our well(s). The conversion to electricity on the expanded portion of the treatment plant is expected to reduce shrinkage of our natural gas that occurs in the treating process.

Originally, the MGP Agreement required MGP to complete the additional treating facilities by March 1, 2006. However, due to events of force majeure, construction of the additional treating facilities was delayed. In early November 2007, MGP began testing the additional treatment facilities by accepting 20 MMcf/d at the inlet. Subsequently in December 2007, MGP suspended the operations of the additional treatment facilities in order to make modifications to more effectively deal with the presence of diamondoids in the gas stream produced from the Rodessa Formation. A diamondoid is a rare, naturally occurring compound that can segregate out of the gas stream upon a decrease in temperature and pressure and as such, could cause operational problems for the nitrogen rejection portion of the additional treating facilities. MGP obtained a detailed laboratory composition analysis of the diamondoids which indicated that removal of the diamondoids will require flowing the natural gas stream through a diesel contactor after the gas stream has had the hydrogen sulfide and carbon dioxide removed. MGP also conducted a field pilot test which successfully confirmed the laboratory results. Through this contactor process, the diesel will absorb the diamondoids from the gas stream prior to entry into the nitrogen removal tower.

During 2008, MGP analyzed various options for removing the diamondoids; however, they did not complete the necessary plant system modifications. On December 31, 2008, we purchased the gas treatment plant and related gathering pipelines from MGP in exchange for the assumption of secured bank debt, payment of certain outstanding payables of MGP and shares of GeoPetro s common stock.The secured bank debt we incurred as part of the Plant acquisition totaled $6.7 million and is in the form of a 3 year loan with the lender, Bank of Oklahoma, National Association (BOK). The loan agreement provides for minimum quarterly principal payments of $150,000 and supplemental principal amounts payable upon GeoPetro achieving certain cash flow thresholds. The Company has pledged its Madisonville natural gas reserves as well as the Plant assets as collateral for the loan. There is a loan fee of $60,000 payable annually for any yearly period during which any principal remains

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outstanding under the loan. There is no prepayment penalty. GeoPetro and its wholly owned subsidiary Redwood Energy Production, LP (Redwood) are guarantors of the loan.

The effective date of the acquisition was December 31, 2008 and the current owner of the Plant is GeoPetro s wholly-owned, indirect subsidiary, Madisonville Midstream LLC (MM). We expect to complete installation of the system modifications required in the new plant in 2010. In the meantime, the existing, in service portion of the plant continues to operate with a capacity of approximately 18 million cubic feet per day of inlet gas.

Our natural gas deliveries to our gas treatment plant may be affected by third party demands for access to the plant. On August 9, 2006, the Texas Railroad Commission issued an order requiring the Plant to ratably process, take, transport or purchase natural gas produced by Crimson into the Madisonville gas treatment plant. There is no guarantee that we will be able to maintain full access to treatment capacity of up to 68 MMcf/d at the Madisonville Plant at all times because, for example, Crimson now has the right to have its natural gas treated at the plant, which may reduce the plant s ability to treat all of our natural gas, unless the plant s capacity is further expanded.

To date, Crimson has drilled and completed two wells to a depth of approximately 12,635 feet. Crimson has also drilled an injection well for disposal of waste products resulting from the treatment of their natural gas. Crimson has not delivered any natural gas to the treatment plant since August 2009.

Other Interests in the Madisonville Project

Our working interest in the Madisonville Project is subject to a net profits interest in favor of the third party that sold us our working interests in the Madisonville Project. The net profits interest is 12.5% (proportionately reduced to our interest) of the net operating profits until payout is achieved. After payout, the net profits interest increases to 30% (proportionately reduced to our interest).   Payout , for purposes of the net profits interest, is defined and achieved at such time as we have recouped from net operating cash flows our total net investment in the Madisonville Project plus a 33% cash on cash return.

Alaska

The Cook Inlet Alaska Project

Over the past five years, we acquired a 100% working interest in approximately 123,000 acres onshore in the Cook Inlet region of Alaska (the   Alaskan Leases). The leasehold position consists of two separate target areas, the Point MacKenzie Prospect and the Trading Bay Prospect, which have been selected for oil and gas exploration. The Point MacKenzie Prospect is located twelve miles northwest of Anchorage. The Trading Bay Prospect is located fifty miles west of Anchorage across the Cook Inlet. GeoPetro believes that the acreage may contain significant accumulations of conventional oil and gas and coal bed methane.

On February 26, 2010, we sold our entire working interest in the Alaskan Leases to Linc Energy (Alaska) Inc. (Linc). Linc is a wholly-owned subsidiary of Linc Energy Ltd., an Australian-based company publicly traded on the Australian Stock Exchange.

Linc will acquire all of the Alaskan Leases for the following consideration:

a. A cash payment of $1.0 million will be deposited by Linc in an escrow account, to be released to us upon approval of the assignments of the Alaskan Leases to Linc.

b. In addition, we will receive a $4.0 million payment from the first 75% of 8/8ths of the proceeds from any oil and gas production from the Alaskan Leases.

c. After we have received the $4.0 million payment specified in paragraph (b) above, we will thereafter receive an overriding royalty interest of 10% of 8/8ths in and to the Alaskan Leases issued by the State of Alaska and the Alaska Mental Health Trust (which comprise over 99% of the Alaskan Leases), and an overriding royalty interest of 7% of 8/8ths in and to the Alaskan Leases issued by Cook Inlet Region, Inc. on conventional oil and gas production and coal bed methane production.

d. Linc has agreed to pay all of the costs of maintaining the Alaskan Leases at least through the end of the primary terms thereof.

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e. Following the lessors approval of the assignments of the Alaskan Leases into Linc, Linc will diligently commence and prosecute the drilling of the Frontier Spirit #1 exploration well to evaluate a conventional oil and gas prospect identified and developed by us.

The initial reserve target in the Cook Inlet Project was identified by us after we reprocessed certain 2-D seismic data acquired from AMOCO on the Point MacKenzie Block. The prospect is estimated to cover approximately eighteen sections (11,500 acres) under structural closure, and will target conventional gas reserves in the Middle and Lower Tyonek Formations reaching to a depth of approximately 8,000 feet. We have constructed a drill pad and access road at the Frontier Spirit #1 location which will be located less than two miles from the Enstar 20 natural gas pipeline. The Frontier Spirit #1 well is expected to be drilled by Linc in 2010.

Preliminary log analysis and seismic data indicate the Point MacKenzie and Trading Bay Blocks may contain conventional accumulations of natural gas reserves in Tertiary sandstones in addition to the prospect identified at the Frontier Spirit #1 location. Structural anticlines and/or domes occur on the lease blocks and may contain large undrilled gas reservoirs. Sandstone units also pinch-out toward the margins of the basin and may have formed stratigraphic traps on the lease blocks. In the past, oil and gas exploration has focused on oil production and anticlinal gas traps, but stratigraphic accumulations have been largely unexplored in the Cook Inlet.

Additional potential on the Alaskan Leases may be realized from the development of coal bed methane reserves. The coals occur in seams which are commonly 20 feet thick and can be as thick as 70 feet. Accessible onshore areas have 200 to 300 feet of aggregate coal thickness shallower than 5,000 feet. Estimated gas content for these coals ranges from 80 to 250 standard cubic feet per ton. Testing for coal bed methane has been restricted to a very small number of bore holes and is almost completely unknown for most of the inlet.

California

Lokern Project

We have 100% working interests in 1,280 lease acreage in the Lokern Project, located in the southern San Joaquin basin, near Bakersfield, California. The primary exploration objective is the Miocene Stevens formation. The secondary objectives include the Miocene Reef Ridge and Pliocene Etchegoin sands. The Stevens formation is Upper Miocene age.

The Lokern Project is being developed in part as a result of positive results from the Machii-Ross Ackerman show well drilled in 1979 on acreage currently controlled by us. Based on log analysis, we believe this well had approximately 240 feet of potential net oil pay and an additional 150 feet of potential pay in the Stevens zone. The Machii-Ross Ackerman well was drilled to a depth of 15,078 feet by Machii-Ross Petroleum Company and was plugged and abandoned as a dry hole. We believe, based on our log analysis, that the well may have been a bypassed producer.

We expect that a well will be drilled, either by us or through a farmout arrangement with a third party, to a depth of 18,000 feet in 2011.

Based on our review of title information from public authorities and other publicly available sources, we believe that we have a 100% working interest in the Lokern Project. As is customary in the U.S. oil and gas industry, we will not conduct a thorough title review with respect to our interest in the Lokern Project until we have made a definitive decision to drill in a particular lease area.

Alberta

Swan Hills Project

The Swan Hills Project is located in the Central Alberta Basin, Alberta, Canada. The primary exploration objective is the Swan Hills Formation at approximately 9,000 feet. Secondary objectives will include the shallower Gilwood, Nordegg and Falher formations.

We, through our wholly-owned subsidiary, GeoPetro Canada, have reviewed 3-D seismic data over the prospect and plan to participate in the drilling of a test well. We have a 33% non-working interest in approximately 4,480 gross leased acres (1,493 net acres).

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Indonesia

C-G Bengara owns 100% of the underlying rights to explore for and produce oil and natural gas within the contract area designated as the Bengara II Block, which rights have been granted under a production sharing contract dated December 4, 1997 (the **Bengara II PSC**) with Pertamina. Previously we owned 40% of CG Bengara and Continental Energy Corporation (**Continental**) owned the remaining 60% and, through it, the rights to the Bengara II PSC. On September 29, 2006, we executed a definitive agreement to sell 70% of our interest in C-G Bengara to CNPCHK (Indonesia) Limited (**CNPC**). We have retained a 12% stake in C-G Bengara and the Bengara II PSC. Continental has likewise sold its interest and retained an 18% interest in C-G Bengara and the Bengara II PSC.

The Bengara Block is located in the Tarakan Basin, mostly onshore but partially offshore astride the Bulungan River Delta in the Indonesian province of East Kalimantan. It originally covered a single contiguous area of approximately 1.2 million gross acres, of which 300,000 gross acres were relinquished in 2001 and an additional 300,000 gross acres were relinquished in 2007 by C-G Bengara in accordance with the terms of the Bengara II PSC. C-G Bengara has tendered an additional relinquishment such that the remaining acreage within the Bengara II PSC total approximately 240,000 acres, or 970 square kilometers as discussed below.

The Makapan Gas Field

Since 1938, only two wells have been drilled in the Bengara Block prior to 2007, one of which resulted in the discovery of the Makapan Gas Field. The Muara Makapan No. 1 well was drilled in 1988 by P.T. Deminex Indonesia from a swamp barge positioned on one of the Bulungan River Delta mouth channel distributaries. The well was drilled to a total depth of 10,800 feet and tested 19.5 MMcf/d together with 600 bbls of 54 degree API condensate per day from a 33 feet thick sandstone section near 6,000 feet. The well was plugged and abandoned as a natural gas discovery. Several other gas zones indicated on logs were not tested. The well was not produced nor were any confirmation wells drilled due to the lack of a local natural gas market at the time the well was drilled. The Makapan Gas Field gas is a Wet gas with a high LPG fraction which may be commercial to extract at the wellhead for a third revenue source in addition to the gas and condensate. The Makapan Gas Field lies mostly offshore in very shallow water, less than 10 feet, amidst numerous islands of the Bulungan River Delta.

Exploration in the Bengara Block

We believe that the key to successful prospecting in the Bengara Block will be the identification of traps and understanding sand distribution.

Nearly 2,200 line kilometers of 2-D seismic data available within the Bengara Block appear to be adequate for both detailed and reconnaissance interpretation purposes. Some localized areas may benefit from reprocessing. New seismic data is required in places where insufficient data exists and for prospect confirmation in other locations.

Several separate and unique geologic plays within the Bengara Block, as well as a number of prospects and leads, have been identified. Some well-defined prospects present immediate drilling targets. Exploration within the Bengara Block is in its formative stages and it is premature to make meaningful resource or reserve estimates. However, the existing exploration work to date indicates that there may be potential petroleum accumulations in the Bengara Block. Analysis of source rocks indicates a propensity for both oil and natural gas.

Terms of Participation in the Bengara Block

The Bengara II PSC is a standard terms PSC employed by BP Migas for all oil and natural gas concessions in Indonesia. Generally, the joint venture participants are entitled to receive, from production proceeds, 100% of expenditures in the block as cost recovery . Once these costs are recovered, C-G Bengara is entitled to a production share of approximately 26.7% of oil produced and 62.5% of all natural gas produced. We will be entitled to 12% of C-G Bengara s share of any such production. Sharing terms for certain categories of oil vary slightly as defined in the Bengara II PSC. The term of the contract is thirty years from December 1997 or a shorter period if C-G Bengara elects to terminate its obligations under the contract or if no commercial hydrocarbons are discovered within the contract area. At the end of six years, unless mutually extended by C-G Bengara and BP Migas, the contract expires if no commercially producible hydrocarbons have been discovered in the contract area. C-G Bengara and BP Migas have mutually extended the early termination provisions until December 3, 2011. C-G Bengara may terminate the contract at any time by relinquishing all of its rights and obligations under the contract area. C-G Bengara is required to relinquish 25% of the contract area within the first three years of the contract, a further 25% of the contract area within six years from the commencement of the contract and an additional area within the first ten years so that the area retained thereafter shall not be in excess of 970 square kilometers, or 20% of the original total contract area, whichever is less. C-G

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Bengara may designate which areas are to be relinquished subject to approval by BP Migas. C-G Bengara s obligation to relinquish parts of the original contract area under these provisions does not apply to the surface area of any field in which petroleum has been discovered. To date, acreage has been relinquished by C-G Bengara in accordance with the terms of the Bengara II PSC such that the remaining acreage within the Bengara II PSC totals approximately 240,000 acres, or 970 square kilometers. The remaining 240,000 acres is considered by C-G Bengara to be the most prospective portion of the original 1.2 million acre block.

C-G Bengara is required to pay to BP Migas specified amounts based on achieving certain cumulative production quantities of crude oil from the contract area when and if commercial production is established. These production bonuses are as follows:

Cumulative Production		**Cash Bonus Due**
25,000,000 boe	$	500,000
60,000,000 boe	$	1,500,000
100,000,000 boe	$	2,500,000

In order to maintain the Bengara II PSC in effect, C-G Bengara was required to complete the work programs and expenditures totaling $25 million during the first ten years of the contract. C-G Bengara has fulfilled such minimum work and cash expenditure requirements.

Upon establishing commercial production, if ever, C-G Bengara and BP Migas shall share ratably in the first 20% of oil and natural gas produced in the contract area within a given year according to the percentages specified below. After the first 20% of production, C-G Bengara is entitled to receive 100% of production until cost recovery has been achieved. Cost recovery generally includes 100% of the operating and drilling costs and depreciation of fixed assets applicable to oil and natural gas operations within the contract area. After C-G Bengara has received oil and natural gas production with a value sufficient to achieve cost recovery in a given year, C-G Bengara and BP Migas shall then share ratably in the production according to the percentages specified below:

Description	**BP Migas**	**C-G Bengara**	**Our net share**
Oil production	73.2143%	26.7857%	3.2143%
Gas production	37.5%	62.5%	7.5%

Upon the completion of five years after commercial production commences, C-G Bengara is further subject to a domestic market obligation. This obligation requires C-G Bengara to sell and deliver to BP Migas, to meet Indonesia s domestic crude oil needs, a specified quantity of crude oil at a price which is only 15% of the market price of the oil. However, for new fields, for a period of five years starting on the month of the first delivery of crude oil produced from a new field, the fee per barrel for such crude oil supplied to the Indonesian domestic market shall be the market price, with the condition that the excess over the 15% of market price shall preferably be used to assist financing of continued exploration efforts in the contract area.

Upon the first commercial discovery of oil or natural gas in the contract area, BP Migas has the right to demand that 10% of C-G Bengara s undivided interest in the total rights and obligations under the Bengara II PSC be offered to itself or an entity owned by Indonesian nationals. The 10% interest shall be offered at a dollar amount equal to 10% of C-G Bengara s cumulative costs incurred in the contract area.

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Current and Planned Activities in the Bengara Block

In accordance with the terms of our agreement dated September 29, 2006 pursuant to which we sold 70% of our interest in C-G Bengara to CNPC, CNPC:

1. Purchased 14,000 and 21,000 shares of C-G Bengara from us and Continental, respectively, at a cost of $1 per share. As a result of the transaction, we and Continental own 6,000 and 9,000 C-G Bengara shares, respectively, retaining a 12% and 18% interest in C-G Bengara, respectively.

2. Paid the sum of $18.7 million (the **Earning Obligation**) into a special joint venture account at a Hong Kong international bank. The funds were expended exclusively to pay for exploration and/or appraisal drilling in the Bengara II PSC area.

3. Agreed to provide development loans to pay 100%, and thereby carry our share and Continental s share of all C-G Bengara s exploitation, drilling, and development expenditures attributable to the Bengara II PSC, after the Earning Obligation funds are expended and a Plan of Development has been approved by BP Migas, until an additional amount of U.S. $41.3 million over and above the Earning Obligation funds has been expended.

4. Agreed to pay a cash bonus totaling $5,000,000, in the proportions of $2,000,000 to us and $3,000,000 to Continental, respectively, contingent upon and within fourteen business days of the receipt by C-G Bengara of the written approval from governmental authorities approving the development of the first commercial oil or gas discovery within the Bengara II PSC contract area.

During 2007, C-G Bengara drilled a total of four wells on the Bengara II PSC: the Seberaba-1, the Seberaba-3, the Seberaba-4, and the Punga-1. The technical information provided by drilling and testing results to date confirm the presence of an oil accumulation. However the data is not yet adequate to conclusively demonstrate the extent of the oil accumulation or that it has sufficient size of oil reserves to economically justify a full commercial development. Further technical information is required prior to commencing development. C-G Bengara has prepared a preliminary plan of development for the Seberaba discovery based upon drilling and testing results from the Seberaba-1 and 3 wells. In addition to these well test results, C-G Bengara believes additional technical information is needed prior to finalizing the formal plan of development and submitting it for approval to Indonesian oil and gas authorities. Approval of the formal plan of development will automatically invoke the final 20-year production period of the Bengara-II PSC through December 4, 2027.

During 2009 C-G Bengara awarded a contract to a seismic acquisition contractor to conduct a seismic acquisition program in the Bengara-II Block. Work is presently underway to acquire a total of 120 square kilometers of 3D seismic and 844 line kilometers of 2D seismic at an estimated acquisition cost of $ 28.5 million. The primary objective of the 3D seismic program is to further define and delineate the Seberaba oil discovery and the Makapan gas/condensate discovery. CGB2 is eyeing a joint development of Makapan gas with Seberaba oil to achieve economies of scale and provide a gas source for fuel, pressure maintenance, and artificial lift of oil.

A large part of the 2D seismic program is also intended to provide additional definition of other exploration prospects in the Bengara-II Block to firm up new exploration drilling targets for a proposed 2010/2011 drilling program. A large portion of the seismic acquisition program shall be conducted in the logistically difficult and higher cost transition zone between a shallow marine offshore and onshore setting. The eastern portion of the Block is located mostly onshore but partially offshore in the shallow waters of the Sulawesi Sea and the Bulungan River delta.

C-G Bengara has received approval of the Indonesian government for an extension of time under the Bengara-II PSC to appraise, assess, and justify the economic feasibility of commercial development of the apparent oil discovery made on the Seberaba prospects during exploratory drilling in 2007 as noted above. The extension is valid until December 3, 2011 and may be extended for subsequent years subject to further approval based on an annual review of progress and results of appraisal work.

CG Xploration

In November 2005, we and Continental formed CG Xploration to pursue new venture oil and gas exploration and production projects and obtain new exploration concessions in Indonesia. CG Xploration Inc. is incorporated in Delaware and is owned 50% by us and 50% by Continental. CG Xploration Inc. may acquire new venture opportunities on behalf of ourselves and Continental. To date, CG Xploration has not completed any acquisitions.

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Australia

On June 20, 2007, the Company agreed to sell and transfer all of its remaining property interests in Australia to an unrelated party for cash consideration and a Petroleum Sales Royalty Payment equal to 25% of the future annual earnings before interest, taxes, depreciation and amortization from the property interests. Specifically, the agreement provides that the Company will be paid consideration for the sale and transfer of its property interests as follows:

1. Initial cash consideration of $175,000 was received on November 19, 2007;

2. a second cash payment of $175,000 upon a successful flow test of petroleum from a well located on the property interests. A successful flow test is defined for purposes of this agreement to be a test of at least 7 million standard cubic feet of natural gas for a continuous and uninterrupted 24 hour period (or an equivalent oil/condensate rate based on a conversion ratio of 6000 cubic feet of gas to a barrel of oil or condensate); and,

3. a Petroleum Sales Royalty Payment equal to 25% of the future annual earnings before interest, taxes, depreciation and amortization from the property interests up to a total amount of $2,200,000.

Proved Reserves Disclosures

Recent SEC Rule-Making Activity In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserves reporting requirements. The most significant amendments to the requirements that impact us included the following:

- Commodity Prices Economic producible reserves and discounted cash flows are now based on a 12-month average net natural gas price unless contractual arrangements designate the price to be used.

- Disclosure of Unproved Reserves Probable and possible reserves may be disclosed separately on a voluntary basis. We are not presently disclosing probable and possible reserves, but may do so in the future.

- Proved Undeveloped Reserves Guidelines Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.

- Reserves Estimation Using New Technologies Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

- Reserves Personnel and Estimation Process Additional disclosure is required regarding the qualifications of the chief technical person(s) who oversee the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.

- Disclosure by Geographic Area Reserves in foreign countries or continents must be presented separately if they represent more than 15% of our total oil and gas proved reserves. We presently do not report reserves in foreign countries or continents, but may do so in the future as a result of our exploration activities.

- Non-Traditional Resources The definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

We adopted the rules effective December 31, 2009.

Effect of Adoption - Application of the new reserve rules resulted in the use of a lower natural gas price at December 31, 2009 than would have resulted under the previous rules. The new pricing methodology rules resulted in a lower net present value (PV-10) of economically producible reserves. The prices under the new rules were $3.11 per Mcf for natural gas adjusted for energy content, quality and basis differentials. Under the new rules, this resulted in a year-end ceiling test write-down of $19.8 million associated with the US full cost pool. Had we used the price prevailing on December 31, 2009 of $5.45 per Mcf for natural gas, there would have been no year-end ceiling test write-down. Under full cost accounting, a ceiling test is performed to ensure that unamortized capitalized costs in each cost center (country) do not exceed their fair value. Impairment is recognized when the carrying value is greater than the discounted future cash flows. In the event of impairment, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings. The present value of estimated future net revenues is computed by applying current oil and gas prices to estimated future production of proved oil and gas

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reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves assuming the continuation of existing economic conditions.

Use of new 12-month average pricing rules at December 31, 2009 also resulted in a decrease in economically producible proved reserves of approximately 1.03 Bcf. Use of the old year-end prices rules would have resulted in a decrease in proved reserves of approximately 0.53 Bcf at December 31, 2009. Therefore, the total impact of the new price methodology rules resulted in negative reserves revisions of 0.5 Bcf.

The use of the new pricing methodology had an insignificant impact on our depletion expense in the fourth quarter of 2009.

Internal Controls Over Reserves Estimates Our policies regarding internal controls over the recording of reserves estimates requires reserves to be in compliance with the SEC definitions and guidance and prepared in accordance with generally accepted petroleum engineering principles.

The Company engaged the independent petroleum engineering firm, MHA Petroleum Consultants, LLC (MHA) to prepare the Company s reserve estimates at December 31, 2009, 2008 and 2007. MHA is a Denver based group of approximately 30 professional engineers and geologists providing a wide range of technical services to the petroleum industry. Within MHA, the technical persons primarily responsible for preparing the estimates set forth in the MHA reserves report incorporated herein are Mr. John Arsenault and Mr. Dennis Holler. Mr. Arsenault has been practicing consulting petroleum engineering at MHA since 2006, and has over 23 years of practical experience in petroleum engineering, with over 10 years experience in the estimation and evaluation of reserves. Mr. Holler has been practicing consulting petroleum geology at MHA since 2001. Mr. Holler has over 35 years of practical experience in petroleum geology, with over 25 years experience in the estimation and evaluation of reserves. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geosciences evaluations as well as applying SEC and other industry reserves definitions and guidelines. MHA evaluated properties representing 100% of our reserves, valued at the total estimated future net cash flows before income taxes, discounted at 10% (PV-10), for all periods presented below. Senior members of our management review the final reserve report to ensure the accuracy and completeness of all inputs into the report. MHA s report to management, which summarizes the scope of work performed and its conclusions, has been included in this report as Exhibit 99.1

Proved Undeveloped Reserves (PUDs) - As of December 31, 2009, our PUDs totaled 8.4 Bcf of natural gas.

- *PUD Locations* - 100% of our PUDs at year-end 2009 were associated with a location in the Madisonville Field.

- *Changes in PUDS* - Changes in PUDs that occurred during the year were due to two reasons. The first reason is that one Probable location from the year end 2008 report was moved to a PUD in the year end 2009 report. This change was based on the overall Proved volumetrics for the field (which did not change year over year), and a decline in the volumes assigned for existing Proved Developed locations because of reservoir geometry. The second reason is that the hydraulic fracture treatment for the existing Wilson well in conjunction with the necessary plant upgrade to handle the increased volume of gas have been moved into the PUD category because of the relatively large expense required to achieve the predicted rates.

- *Development Costs* - No *c*osts were incurred relating to the development of PUDs in 2009 and 2008.

- Estimated future development costs relating to the development of PUDs are projected to be approximately $6.6 million in 2010 and 2011.

- *Drilling Plans* - Our PUD development is scheduled in 2010 and 2011. Initial production from the PUD reserves is expected to begin in 2010.

For more information see the following:

- Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Comparison of Results of Operations for the year ended December 31, 2009 and 2008 for a discussion of the financial impact of the SEC revisions;

- Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates Reserves for further discussion of our reserves estimation process;

- Item 8. Financial Statements and Supplementary Data Supplementary Oil and Gas Information (Unaudited) for additional information regarding estimates of crude oil and natural gas reserves, including estimates of proved, proved developed, and proved undeveloped reserves, the standardized measure of discounted future net cash flows, and the changes in the standardized measure of discounted future net cash flows.

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Other Reserves Information Since January 1, 2009, no crude oil or natural gas reserves information has been filed with, or included in any report to, any federal authority or agency other than the SEC and the Alberta Securities Commission. We filed reports with the Alberta Securities Commission in March 2009 that included total proved reserves using forecasted (escalated) natural gas prices inclusive of royalties and net profits interests as of December 31, 2008 totaling 46,168 MMcf. The total net proved reserves using period-end (un-escalated) natural gas prices, excluding royalties and net profits interests, as of December 31, 2008 was 20,470 MMcf. The difference between the two numbers represents proved reserves attributable to royalties and net profits interests as well as the different natural gas price scenarios.

Our estimated total net proved reserves of natural gas and oil as of December 31, 2009 and 2008, and the present values of estimated future net revenues attributable to those reserves as of those dates, are presented in the following tables.

Proved developed oil and gas reserves means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved developed nonproducing reserves means reserves expected to be recovered from zones behind casing in existing wells.

Proved oil and gas reserves - Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(a) The area of the reservoir considered as proved includes:

i. The area identified by drilling and limited by fluid contacts, if any; and

ii. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(b) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(c) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(d) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

i. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

ii. The project has been approved for development by all necessary parties and entities, including governmental entities.

(e) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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The 2009 and 2008 estimates were prepared by MHA Petroleum Consultants, independent reservoir engineers, and are part of their reserve reports on our natural gas and oil properties. MHA Petroleum Consultants estimates were based on a review of geologic, economic, ownership and engineering data that we provided. In estimating the reserve quantities that are economically recoverable, MHA Petroleum Consultants used end-of-period natural gas prices for the 2008 estimates. Prices used for the year ended December 31, 2009 estimates were the simple arithmetic average of the natural gas price in effect on the first day of each month in 2009. In accordance with U.S. Securities and Exchange Commission regulations, no price or cost escalation or reduction was considered. All of our proved reserves are attributable to our Madisonville Project in Madison County, Texas.

	AS OF DECEMBER 31,	
	2009 (MMcf)	**2008 (MMcf)**
Proved developed	3,650	17,300
Proved developed non-producing	6,611	3,170
Proved undeveloped	8,371	
Total	18,632	20,470

In accordance with Securities and Exchange Commission regulations, estimates of our proved reserves and future net revenues are made using sales prices which are held constant throughout the life of the properties, except to the extent a contract specifically provides for escalation. Estimated quantities of proved reserves and future net revenues are affected by natural gas and oil prices, which have fluctuated significantly in recent years.

Standardized Measure of Discounted Future Net Cash Flows

For purposes of the following disclosures, estimates were made of quantities of proved reserves and the periods during which they are expected to be produced. Future cash flows for the 2008 estimates were computed by applying year-end prices to estimated annual future production from proved gas reserves. Future cash flows for the 2009 estimates were computed by applying the simple arithmetic average of the natural gas price in effect on the first day of each month in 2009 to estimated annual future production from proved gas reserves. The price assumptions used for natural gas are indicated below. Future development drilling and production costs were computed by applying year-end costs to be incurred in producing and further developing the proved reserves. Future income tax expenses were computed by applying, generally, year-end statutory tax rates (adjusted for permanent differences, tax credits and allowances) to the estimated net future pre-tax cash flows. The discount was computed by application of a 10% discount factor. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proven to be the case in the past. Other assumptions of equal validity could give rise to substantially different results.

	YEAR ENDED DECEMBER 31,	
	2009	**2008**
	(in thousands)	
Future cash inflows	50,652	$ 107,063
Future production costs	(17,157)	(34,414)
Future development costs	(7,849)	(5,075)
Future income taxes		(7,977)
Future net cash flows	25,646	59,597
10% annual discount	(6,005)	(12,282)
Standardized measure of discounted future net cash flows	$ 19,641	$ 47,315

The standardized measure values shown in the aforementioned table are not intended to represent the current market value of the estimated proved oil and gas reserves owned by us.

Pricing Assumptions

SEC regulations require that the gas prices used in the MHA Petroleum Consultants reserve reports included herewith are the period-end prices for natural gas at December 31, 2008. SEC regulations require that the gas price used for the December 31, 2009 MHA Petroleum Consultants reserve report is the simple arithmetic average of the natural gas price in effect on the first day of each month in 2009. These prices are projected without inflation for the life of the wells included in the reserve reports. The pricing assumptions are listed below and represent the weighted average price for natural gas at December 31st delivered at the Houston Ship Channel before any reductions for transportation and processing fees.

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AVERAGE PRICE 2009 REPORT Gas ($/MMBtu)	YEAR-END PRICE 2008 REPORT Gas ($/MMBtu)
$ 3.11	$ 5.25

Drilling Activities

The following indicates the number of natural gas wells drilled during the periods indicated.

	Productive		Dry		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Year ended December 31, 2009						
Exploratory	0	0	0	0	0	0
Development	0	0	0	0	0	0
Year ended December 31, 2008						
Exploratory	0	0	3	1.15	3	1.15
Development	0	0	0	0	0	0

Acreage and Productive Wells

The following table sets forth our ownership interest in undeveloped acreage, developed acreage and productive wells in the areas indicated where we own a working interest as of December 31, 2009. Gross represents the total number of acres or wells in which we own a working interest. Net represents our proportionate working interest resulting from our ownership in gross acres or wells. Productive wells are wells in which we have a working interest and that are capable of producing natural gas or oil. Wells that are completed in more than one producing horizon are counted as one well.

	Undeveloped acreage		Developed acreage		Producing Wells		Non-Producing Wells	
Acreage Holdings	**Gross Acres**	**Net Acres**	**Gross Acres**	**Net Acres**	**Gross**	**Net**	**Gross**	**Net**
Indonesia	239,692	28,763						
Canada	4,480	1,493						
Texas	5,484	5,484	3,520	3,520	3	3	1	1
California	1,280	1,280						
Alaska	123,050	123,050						
Total	373,986	160,070	3,520	3,520	3	3	1	1

The following table sets forth as of December 31, 2009, the expiration periods of the gross and net undeveloped acreage:

	Undeveloped Acreage					
	United States		**Indonesia**		**Canada**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Twelve months ended						
December 31, 2010	2,490	2,490				
December 31, 2011	1,685	1,685	239,692	28,763		
December 31, 2012	124,151	124,151			4,480	1,493
December 31, 2013	1,310	1,310				
December 31, 2014 and thereafter	177	177				
	129,813	129,813	239,692	28,763	4,480	1,493

Volumes, Prices and Production Costs

Substantially all of our production is derived from our Madisonville Project in Madison County, Texas. The following table sets forth information with respect to our production volumes, average prices received and average production costs for the periods indicated:

	YEAR ENDED DECEMBER 31,			
		2009		2008
Production:				
Natural gas (MMcf) (1)		1,278		1,275
Natural gas (MMcf/d) (1)		3.50		3.49
Average Sales Prices (2)				
Natural gas ($per Mcf) (2)	$	3.19	$	4.82
Lease Operating Expense				
($per Mcf) (3)	$	0.66	$	1.16
Plant Operating Expense (4)				
($per Mcf)	$	3.71		

(1) Production volumes for 2009 represent actual plant throughput. Sales volumes net to our interests in the Madisonville gas wells for the year ended December 31, 2009 amounted to 807 MMcf, or 2.2MMcf/d.

(2) Represents sales price realized net of treatment, gathering and transportation costs in 2008 since we sold the gas at the wellhead to an unaffiliated purchaser. Commencing January 1, 2009, we moved the point of sale of the gas to the outlet of the gas treatment plant since we purchased the gas treatment plant and related gathering systems effective December 31, 2008. Accordingly, the sales price reflected for the year ended December 31, 2009 represents the sales price realized before deducting treatment, gathering and transportation costs, and is based up on plant throughput.

(3) Lease operating expense per Mcf is based on lease operating expense and sales volumes net to our interests in the Madisonville gas wells.

(4) Plant operating expense per Mcf is based on total plant operating expense and actual plant throughput.

Business Risks and Other Special Considerations

Refer to Risk Factors in this report for a discussion of business risks and other special considerations.

Item 3. ***Legal Proceedings***

From time to time, we are party to litigation or other legal and administrative proceedings that we consider to be a part of the ordinary course of our business. Currently, we are not involved in any legal proceedings nor are we party to any pending or threatened claims that could, individually or in the aggregate, reasonably be expected to have a material adverse effect on our financial condition, cash flow or results of operations, except as follows:

On September 11, 2009, the Company s subsidiary, Redwood Energy Production, L.P. filed an Original Petition for Declaratory Judgment against Devon Energy Production Company (Devon) regarding certain overriding royalty interests and related revenue amounts claimed by Devon. The Company previously accrued all amounts owed pursuant to these overriding royalty interests as royalty owners payable. In the opinion of management based on consultation with legal counsel, these proceedings are not expected to have a material adverse effect on our financial condition or results of operations.

Item 4. ***Reserved***

Not applicable.

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PART II

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

Our common stock trades on the NYSE Amex under the symbol GPR . On March 30, 2010, the last reported sale price for our common stock on the NYSE Amex was $0.61. The following table sets forth the high and low sale prices of our common shares as reported on the NYSE Amex for the periods presented.

	NYSE Alternext US (1)			
		High		Low
2009				
Fourth Quarter	$	1.05	$	0.57
Third Quarter	$	1.35	$	0.33
Second Quarter	$	0.78	$	0.33
First Quarter	$	1.27	$	0.21
2008				
Fourth Quarter	$	2.28	$	0.48
Third Quarter	$	4.12	$	1.90
Second Quarter	$	4.29	$	2.25
First Quarter	$	3.58	$	2.00

(1) Our common stock commenced trading on the American Stock Exchange on February 15, 2007. On December 1, 2008, the American Stock Exchange was merged with the NYSE Exchange.

(2) As of March 12, 2010, there were 301 holders of record of our common shares.

Incentive Stock Plan and Stock Option Plan

Effective as of September 10, 2001, the board of directors approved an incentive stock plan, providing for awards under the terms and provisions of such plan of incentive stock options, stock appreciation rights and restricted stock awards to officers, directors and employees of GeoPetro and its consultants (the Stock Incentive Plan). The plan provides, among other provisions, the following:

The maximum number of Common Shares which may be awarded, optioned and sold under the plan is 5,000,000 (subject to adjustment for stock splits, stock dividends and certain other adjustments to GeoPetro s common stock); and the per share exercise price for Common Shares to be issued pursuant to the exercise of an option shall be no less than the fair market value of GeoPetro s Common Shares as of the date of grant.

The Stock Incentive Plan provides for the granting to employees incentive stock options within the meaning of Section 422 of the United States Internal Revenue Code of 1986, as amended, and for the granting of non-statutory stock options to directors who are not employees and consultants. In the case of employees who receive incentive stock options which are first exercisable in a particular calendar year and the aggregate fair market value of which exceeds $100,000, the excess of the $100,000 limitation shall be treated as a nonstatutory stock option under the Stock Incentive Plan.

The Stock Incentive Plan is being administered by the Board of Directors. The Board of Directors determines the terms of the options granted, including the number of Common Shares subject to each option, the exercisability and vesting requirements of each option, and the form of consideration payable upon the exercise of such option (i.e., whether cash or exchange of existing Common Shares in a cashless transaction or a combination thereof). The Stock Incentive Plan will continue in effect for 10 years from September 10, 2001 (i.e., the date first adopted by the Board), unless sooner terminated by the board of directors.

In 2004, we implemented a new 2004 Stock Option and Appreciation Rights Plan (the Stock Option Plan) providing for awards of incentive stock options, non-qualified stock options and stock appreciation rights. The Stock Option Plan replaced the Stock Incentive Plan as to new award grants effective in 2004 or thereafter to our directors, officers, employees and consultants. Outstanding awards issued under the Stock Incentive Plan will continue to be outstanding in accordance with their terms and the terms of the Stock Incentive Plan, but will count toward the limits in the number of shares of common stock available to be issued under the Stock Option Plan, which is 5,000,000. The exercise price of stock options granted under the Stock Option Plan may not be less than 110% of the fair market value of our common stock on the date of grant.

Dividends

The holders of Series B preferred stock are entitled to receive ratably such cash dividends, as were declared from time to time by the board of directors out of funds legally available therefor and, when declared, dividends were paid at the rate of $0.06 per share per annum, paid on a calendar quarter basis. During 2009, we incurred $179,045 in dividends associated with the Series B preferred stock, of which $68,583 had been paid as of December 31, 2009.

The holders of our common stock shall be entitled to receive ratably such lawful dividends as may be declared by the Board of Directors. We have never paid any dividends, whether cash or property, on our common stock. For the foreseeable future it is anticipated that any earnings which may be generated from our operations will be used to finance our growth and that dividends will not be paid to common stockholders.

Use of Proceeds

On our registration statement on Form S-1 (Reg. No. 333-135485) we registered up to 16,499,991 shares of our common stock, no par value per share, including 5,943,105 shares of common stock issuable upon exercise of warrants and options, for resale by selling shareholders. The registration statement was declared effective by the Securities and Exchange Commission in February 2007. The offering commenced on in February 2007 and has not terminated. On our registration statement on Form S-1

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(Reg. No. 333-146557) we registered up to 2,002,599 shares of outstanding common stock and the resale of up to 780,857 shares of common stock issuable upon exercise of warrants, for resale by selling shareholders. The registration statement was declared effective by the Securities and Exchange Commission in October 2007. The offering commenced in October 2007 and has not terminated. We will not receive any proceeds from the sale of our common stock by the selling shareholders under the registration statements; however, if all warrants and options to acquire our common stock being registered thereunder are exercised, we will realize cash proceeds of approximately $12,168,321, which we expect to use for general working capital purposes and the drilling of wells in our Texas, California, Canadian and Indonesian prospects.

If less than the $12,168,321 proceeds are realized from the exercise of such warrants and options, the proceeds will be spent in the following order of priority:

1. Madisonville Project, Madison County, Texas Approximately $3,028,000 may be expended in the Madisonville Field area as follows: $1,433,000 million for capital maintenance and repair on new gas treatment plant; $945,000 toward the fracture stimulation and hook up costs of the Wilson Well; and $650,000 for the Mitchell well workover.

2. California Approximately $500,000 to be utilized for land and permitting costs.

We do not know if, or how many, of the warrants or options will be exercised. This is our best estimate of our use of proceeds generated from the possible exercise of warrants or options based on the current state of our business operations, our current plans and current economic and industry conditions. Any changes in the projected use of proceeds will be made at the sole discretion of our board of directors.

Unregistered Sales of Securities

During October 2009, we issued 3,401,996 shares of Series B Preferred Stock for total gross proceeds of 2,551,500 pursuant to preferred stock purchase agreements with 31 accredited investors. We issued the Series B Convertible Preferred Stock in reliance on the exemption from registration provided for under Section 4(2) of the Securities Act, and Rule 506 of Regulation D thereunder. We relied on the exemption from registration provided for under Section 4(2) of the Securities Act based in part on the representations made by the investors, including the representations with respect to the investors status as accredited investors, as such term is defined in Rule 501(a) of the Securities Act, and the their investment intent with respect to the shares purchased. We paid $134,600 in cash and issued 170,190 warrants (exercisable at $1.00 per share) as finders fees and commissions in connection with this offering.

During October 2009, GeoPetro raised $720,000 (before fees) by issuing an unsecured subordinated promissory note to an accredited investor, having the following terms: (i) 10% annual simple interest payable at maturity, (ii) principal and any unpaid outstanding interest shall be payable October 31, 2010, (iii) subordinated to the BOK loan and (iv) be unsecured. The note purchaser also received a warrant to purchase 36,000 shares of GeoPetro common stock for $1.00 per share, exercisable for three years. The issuance of the promissory note and warrant was not registered under the Securities Act of 1933, in reliance on Section 4(2) of the Act and Rule 506 of Regulation D thereunder. The person acquiring the note and warrant was an accredited investor, as defined in Rule 501(a) of Regulation D. The issuance of the promissory note and warrant involved no public offering. GeoPetro did not engage in general solicitation or advertising in connection with the issuance and sale of the promissory note and warrant, and did not engage an underwriter.

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Item 6. ***Selected Consolidated Financial Data***

The following selected consolidated financial data should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and the related notes to those statements included elsewhere in this report. The consolidated statements of operations data for the years ended December 31, 2009 and 2008 and the balance sheet data as of December 31, 2009 and 2008 are derived from our audited consolidated financial statements included elsewhere in this report. The consolidated statements of operations data for the years ended December 31, 2007, 2006 and 2005 and the balance sheet data as of December 31, 2007, 2006, and 2005 are derived from our audited consolidated financial statements not included in this report. Historical results are not necessarily indicative of the results to be expected in the future, and the results for the years presented should not be considered indicative of our future results of operations.

	For The Years Ended December 31,				
	2009	2008	2007	2006	2005
Consolidated Statement of Operations:					
Revenues	$ 4,077,355	$ 6,152,542	$ 6,890,777	$ 6,716,360	$ 7,975,990
Plant operating expense	4,832,548				
Lease operating expense	606,266	1,484,267	1,558,900	1,602,932	878,176
General and administrative	2,767,385	2,717,121	2,807,091	2,347,447	1,551,747
Net profits expense		579,941	679,337	632,708	856,837
Impairment expense	20,843,305	69,856	1,111,151	38,849	
Depreciation and depletion expense	1,595,597	1,553,418	2,269,995	2,406,612	1,832,693
Earnings (loss) from operations	(26,567,746)	(252,061)	(1,535,697)	(312,188)	2,856,537
Net income (loss)	(25,808,260)	(174,825)	(1,616,804)	(482,406)	2,640,471
Net income (loss) attributable to common shareholders	$ (25,987,305)	$ (174,825)	$ (1,616,804)	$ (1,011,806)	$ 2,111,074
Earnings (Loss) per Share:					
Basic	$ (0.76)	$ (0.01)	$ (0.05)	$ (0.04)	$ 0.10
Diluted	$ (0.76)	$ (0.01)	$ (0.05)	$ (0.04)	$ 0.09
Weighted Average Number of Common Shares Outstanding:					
Basic	34,284,646	32,511,251	29,830,447	25,990,868	20,890,841
Diluted	34,284,646	32,511,251	29,830,447	25,990,868	24,001,888
Production Data:					
Natural gas (Mcf)	1,278,434	1,275,445	2,005,359	2,229,059	1,991,105
Natural gas (Mcf/d)	3,503	3,494	5,494	6,107	5,455
Production Data reduced by net profits interests:					
Natural gas (Mcf)	1,118,630	1,116,014	1,754,689	1,950,427	1,742,217
Natural gas (Mcf/d)	3,065	3,058	4,807	5,344	4,773
Average Sales Prices:					
Natural gas (per Mcf)	$ 3.19	$ 4.82	$ 3.44	$ 3.01	$ 4.01

	For the Years Ended December 31,				
	2009	2008	2007	2006	2005
Balance Sheet Information:					

Current assets	$ 3,044,731	$ 1,023,090	$ 5,723,680	$ 2,366,081	$ 1,718,893
Total assets	34,004,213	54,076,005	44,116,606	39,061,478	25,014,826
Current liabilities	4,218,956	3,174,742	2,361,827	3,604,342	3,574,466
Current portion of Long-term liabilities	1,549,829	600,000			
Long-term liabilities	6,051,654	7,078,548	53,726	48,842	26,641
Redeemable Series AA Preferred Stock				5,924,068	5,924,068
Series B Preferred Stock	5,448,602				
Accumulated Deficit	$ (38,172,919)	$ (12,185,614)	$ (12,010,789)	$ (10,393,985)	$ (9,382,179)

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Notes to Selected Financial Data:

(a) For each of the years presented the Company has not paid dividends to any of its common stockholders.

(b) See Item 2. Properties Texas- Madisonville Midstream Gas Treatment Plant and Gathering Facilities for discussion of the acquisition of the MGP Gas Treatment Plant.

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion and analysis should be read in conjunction with accompanying financial statements and related notes included elsewhere in this report. It contains forward looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward looking statements.

Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas and oil, economic and competitive conditions, regulatory changes, estimates of proved reserves, potential failure to achieve production from development drilling projects, capital expenditures and other uncertainties, as well as those factors discussed below and elsewhere in this report, particularly in Risk Factors and Cautionary Notes Regarding Forward Looking Statements , all of which are difficult to predict and which expressly qualify all subsequent oral and written forward-looking statements attributable to us or persons acting on our behalf. In light of these risks, uncertainties and assumptions, the forward looking events discussed may not occur. We do not have any intention or obligation to update forward-looking statements included in this report after the date of this report, except as required by law.

Overview

We are an oil and gas company in the business of exploring and developing oil and natural gas reserves on a worldwide basis. Since inception, we have conducted leasehold acquisition, exploration and drilling activities on our North American, Australian and Indonesian prospects. These projects currently encompass approximately 377,506 gross (163,590 net) acres, consisting of mineral leases, production sharing contracts and exploration permits that give us the right to explore for, develop and produce oil and natural gas. Most of these properties are in the exploration, appraisal or development drilling phase and have not begun to produce revenue from the sale of oil and natural gas. Excluding minor interest and dividend income, our only significant cash inflows until 2003 were the recovery of capital invested in projects through sale or other divestiture of interests in oil and gas prospects to industry partners.

Since 2003, substantially all of our revenue has been generated from natural gas sales derived from the Magness #1, the Fannin #1, and the Mitchell #1 wells in the Madisonville Field in East Texas under spot gas purchase contracts at market prices. Natural gas sales from the Madisonville Field are expected to account for substantially all of our revenues for 2010. We expect the majority of our capital expenditures in 2010 will be for the Madisonville Project.

	For The Years Ended December 31, 2009	2008
Consolidated Statement of Operations:		
Revenues	$ 4,077,355	$ 6,152,542
Plant operating expense	4,832,548	
Lease operating expense	606,266	1,484,267
General and administrative	2,767,386	2,717,121
Net profits expense		579,941
Impairment expense	20,843,305	69,856
Depreciation and depletion expense	1,595,597	1,553,418
Loss from operations	(26,567,746)	(252,061)
Net loss	(25,808,260)	(174,825)
Net loss attributable to common shareholders	$ (25,987,305)	$ (174,825)

Revenue and Operating Trends in 2009

As discussed in the Properties Texas Madisonville Project section of this annual report, in order to produce the gas reserves from the Rodessa Formation, we developed an onsite plan to treat and remove impurities from the Madisonville Project natural gas in order to meet pipeline-quality specifications. In 2003, a third party completed the construction and installation of a

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natural gas treatment plant with a designed capacity of 18 million cubic feet of gas per day (MMcf/d) and associated pipeline and gathering facilities.

In 2005 we secured a commitment from MGP to install and make operational additional treating facilities capable of treating 50 MMcf/d, which combined with the capacity of the current in-service treating facilities will represent a total designed treating capacity of 68 MMcf/d for the Madisonville treatment plant. In early November 2007, MGP began testing the additional treatment facilities by accepting 20 MMcf/d at the inlet. Subsequently in December 2007, MGP suspended the operations of the additional treatment facilities in order to make modifications to more effectively deal with the presence of diamondoids in the gas stream produced from the Rodessa Formation.

During 2008, MGP analyzed various options for removing the diamondoids; however, they did not complete the necessary plant system modifications. On December 31, 2008, we purchased the gas treatment plant and related gathering pipeline from MGP in exchange for assumption of secured debt, payment of certain outstanding payables of MGP and shares of GeoPetro s common stock. The effective date of the acquisition was December 31, 2008 and the new owner of the Plant is GeoPetro s wholly-owned, indirect subsidiary, Madisonville Midstream LLC (MM). We expect to complete installation of the system modifications required in the new plant in 2010. In the meantime, the existing, in service portion of the plant continues to operate with a design capacity of up to approximately 18 MMcf/d of inlet gas.

While there can be no assurance, with acquisition of the gas treatment plant, our goal is to make the necessary upgrades to the plant and increase the production rates from our wells which may result in higher net production and increased revenue during 2010 as compared to 2009 and prior periods. To accomplish the plant upgrades, we will need to raise capital in 2010. Due to the unsettled state of the capital markets, funds may not be available, or may not be available on favorable terms.

Prior to December 31, 2008, the price received for natural gas was determined pursuant to certain agreements which were in effect with MGP. Pursuant to these agreements, MGP purchased the Company s untreated natural gas in the Madisonville Field for each of the producing wells and charged the Company a fixed fee to gather, treat, transport and market its natural gas, provided however, that such fees would not exceed the value of the natural gas. Hydrogen sulphide, carbon dioxide and nitrogen combined comprise about 28% of the gas content. The untreated natural gas is delivered to the Gas Treatment Plant where substantially all the natural gas impurities are removed before delivery to the sales pipeline. As a result of the costs to gather, treat, transport and market the natural gas, we received a net price that is substantially lower than we would otherwise receive if the gas did not contain the 28% of impurities.

Due to weak natural gas prices prevailing for most of 2009, the costs to gather, treat, transport and market the natural gas exceeded the value of the natural gas produced during most of the year.

Industry Overview for the year ended December 31, 2009

During 2009 we experienced significantly deteriorating natural gas prices throughout of the year, with a rebound in prices by the end of the year. The Houston Ship Channel price, the index price prevailing in the locale of our Madisonville Project in Madison County, Texas, as quoted in Gas Daily as of December 31, 2009 was per $5.72 Mcf versus $5.25 per Mcf as of December 31, 2008. Natural gas prices were volatile during 2009 due to over-supply and recessionary concerns earlier in the year and later in the year due to seasonal weather driven demand spurred by unusually cold winter temperatures in many parts of the US.

Company Overview in 2009

Our net loss after taxes for the year ended December 31, 2009 was $25,808,260. From our inception, through mid-2003, we only received nominal revenues from our oil and natural gas activities, while incurring substantial acquisition and exploration costs and overhead expenses which have resulted in an accumulated deficit through December 31, 2009 of $38,172,919. Commencing in May 2003, we placed our Madisonville Project into production. Substantially all of our revenues for the year ended December 31, 2009 were derived from our Madisonville Project, from three producing wells, the UMC Ruby Magness #1 well (the Magness Well), the Angela Farris Fannin #1 well (the Fannin Well), and the Mitchell #1 well (the Mitchell Well).

Comparison of Results of Operations for the year ended December 31, 2009 and 2008

During the twelve months ended December 31, 2009, we had gross natural gas revenues from the treatment plant of $4,006,939 and revenues from treating third party gas in the Plant of $70,416. During this period, our gross production from our wells was 1,278,434 Mcf (production net of royalties of 922,393 Mcf) and our average natural gas price realized was $3.19 per

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Mcf. During the twelve months ended December 31, 2008, we had oil and natural gas revenues of $6,152,542, and our net production was 1,275,445 Mcf of natural gas at an average price of $4.82 per Mcf. Revenues decreased in the twelve months ended December 30, 2009 as compared to the prior year period due to lower production volumes and lower natural gas prices. The 27.68% lower net production volumes for the twelve months ended December 31, 2009 as compared to the same period of 2008 was due to natural declines in the wells. Average natural gas prices were approximately 34% lower for the twelve months ended December 31, 2009 versus the same period in 2008.The average natural gas price of $4.82 per Mcf for the 2008 period was net of treating, gathering, marketing and transportation fees (collectively the Fees) in accordance with our contracts with MGP and Gateway ADAC Pipeline, LLC. The average natural gas price of $3.19 per Mcf for the 2009 period was not net of the aforementioned Fees since the contracts that were in place with MGP were terminated as of December 31, 2008.

Prior to December 31, 2008, revenue was recognized upon delivery of oil and gas production and was shown net of applicable royalty payments, as well as processing, gathering, transportation and marketing fees. As indicated in the preceding paragraph, the Company recognized revenue from the Madisonville Field net of applicable fees to treat, gather, transport and market the Company s natural gas production. The applicable fees were paid to unrelated third parties. On December 31, 2008, the Company completed the acquisition of the Plant from MGP. Commencing January 1, 2009, revenue is being recognized without the netting of applicable royalty payments, as well as processing, gathering, transportation and marketing fees since we have acquired the Plant. For all periods presented, revenue from the Madisonville Field is recognized when the price for gas delivered became fixed and determinable.

Our results of operations for the twelve months ended December 31, 2009 include the operating results of the Plant, but our results of operations for the twelve months ended December 31, 2008 do not include the operating results of the natural gas treatment plant because such acquisition closed on December 31, 2008. The following condensed pro forma information gives effect to the acquisition as if it had occurred on January 1, 2008. The pro forma information has been included in the notes to the financial statements included elsewhere in this document as required by generally accepted accounting principles and is provided for comparison purposes only. The pro forma financial information is not necessarily indicative of the financial results that would have occurred had the acquisition been effective on the dates indicated and should not be viewed as indicative of operations in the future.

		Twelve Months Ended December 31, 2008
Operating revenues	$	15,066,915
Total operating expenses	$	15,954,201
Loss applicable to common stock	$	(1,239,749)
Net loss per share	$	(0.04)

During the twelve months ended December 31, 2009, we incurred plant operating expenses of $4,832,548. Our average plant operating cost for the 2009 period was $3.71 per Mcf on net throughput of 1,302,618 Mcf. We purchased the gas treatment plant effective on December 31, 2008, thus there was no plant operating expense for the comparable 2008 period.

During the twelve months ended December 31, 2009, we incurred lease operating expense of $606,266. Our average lifting cost for the 2009 period was $0.66 per Mcf. During the twelve months ended December 31, 2008, we incurred lease operating expense of $1,484,267. Our average lifting cost for the 2008 period was $1.16 per Mcf. The average lifting cost per Mcf in 2009 was lower due to cost cutting efforts and a reduction of ad valorem property taxes applicable to the wells.

During the twelve months ended December 31, 2009, we incurred no net profits interest expense because we did not generate a net operating profit from our Magness, Fannin, and Mitchell wells. During the twelve months ended December 31, 2008, we incurred net profits interest expense of $579,941 associated with the Magness, the Fannin, and the Mitchell wells. The net profit interest is 12.5% of the net operating profit from our Magness, Fannin, and Mitchell wells.

General and administrative (**G&A**) expenses for the twelve months ended December 31, 2009 were $2,767,385 compared to $2,717,121 for the twelve months ended December 31, 2008. This represents a $50,265 or 1.8% increase over the prior year period. The higher G&A expense incurred in 2009 was due primarily to new options issued during 2009 and 2008.

For the year ended December 31, 2009, impairment expense was $20,843,305 versus $69,856 for the same period of 2008. The 2009 impairment write-downs were due to (i) dry holes drilled on our Canadian oil and gas properties, and (ii) writeoff remaining costs related to the South Bengara due to project cancellation (iii) $19.8 million impairment in the Madisonville project in U.S., which resulted in ceiling test write downs.

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For year-end 2009, new SEC rules were implemented requiring that reserve calculations be based on the un-weighted average first-day-of-the-month prices for the prior twelve months, as contrasted with the previous method which utilized period end prices. The prices under the new rules were $3.11 per Mcf for natural gas adjusted for energy content, quality and basis differentials. Under the new rules, this resulted in a ceiling test write-down of $19,798,390 associated with the US full cost pool. Had we used the price prevailing on December 31, 2009 of $5.45 per Mcf for natural gas, there would have been no year-end write-down. Under full cost accounting, a ceiling test is performed to ensure that unamortized capitalized costs in each cost center (country) do not exceed their fair value. Impairment is recognized when the carrying value is greater than the discounted future cash flows. In the event of impairment, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings. The present value of estimated future net revenues is computed by applying current oil and gas prices to estimated future production of proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves assuming the continuation of existing economic conditions.

Depreciation and depletion expense for the twelve months ended December 31, 2009 was $1,595,597 as compared to $1,553,418 in the same period of 2008, which amounts primarily represent depletion of the oil and gas properties for the twelve months ended December 31, 2009 and 2008, respectively. The 2.7% increase was due to gas processing plant depreciation in 2009 which offset decreased depletion expense resulting from lower net production in the twelve months period of 2009 as previously discussed.

Loss from operations totaled $26,567,746 for the twelve months ended December 31, 2009 as compared to loss from operations of $252,061 for the twelve months ended December 30, 2008. The increase in the loss from operations was due primarily to higher impairment, depreciation and depletion expenses.

Other income for the twelve months ended December 31, 2009 and 2008 consisted of interest income in the amount of $6,404 and $91,867, respectively, resulting from lower average cash balances due to our purchase of the Plant on December 31, 2008.

During the twelve months ended December 31, 2009 and 2008, we incurred interest expense of $735,596 and $1,846, respectively. We incurred new debt in late December 2008 and subsequently during 2009 associated with the plant acquisition and working capital requirements.

Net loss before taxes for the twelve months ended December 31, 2009 was $25,809,251 as compared to $162,040 for the twelve months ended December 31, 2008. The increase in net loss during the twelve months ended December 31, 2009 was primarily due to lower gas prices, lower production volume, higher operating expenses, ceiling test write-off in the US pool due to new SEC requirment.

Income tax benefit for the twelve months ended December 31, 2009 was $991 compared to income tax expense of $12,785 in the same period of 2008. The increased income tax benefit was due to refund from 2008 Texas franchise tax overpayment.

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Recent Developments

During the twelve months ended December 31, 2009 we borrowed $850,000 pursuant to five separate three year loans which were convertible into a newly designated class of preferred stock of GeoPetro, Series B Convertible Preferred Stock (the Series B Preferred Stock) and $1,897,000 pursuant to eleven separate loans. The $850,000 in loans converted into Series B Preferred Stock on April 30, 2009, along with an additional $1,000,000 which was advanced during April for a total subscription in the private placement of 2,466,670 shares for a purchase price of $0.75 per share and an aggregate investment of $1,850,000. The holders of Series B Stock are entitled to receive an annual dividend at the rate of $0.06 per share and are entitled to such number of votes per share as equals the number of common shares into which each share of Series B Stock is convertible. Each share of Series B Stock is convertible, at the option of the holder, into fully paid and non-assessable common shares on a one-for-one basis, subject to certain adjustments. The Series B Stock will automatically convert into common shares on a one-for-one share basis effective the first trading day after the reported high selling price for the Company s common shares on any international, national or regional securities exchange or inter-dealer quotation system including but not limited to, NASDAQ, the Pink Sheets or the Over-the-Counter Bulletin Board, is at least $1.50 per share for any ten consecutive trading days. If an automatic conversion occurs within one year after the Series B Stock was purchased from the Company, a holder will receive, on the one-year anniversary date of his, her or its purchase, a cash dividend equivalent to a full year of dividends less any dividends paid before such conversion.

In accordance with the provisions of an agreement with Adelphi Energy Limited (Adelphi) and our wholly owned subsidiary, GeoPetro Resources (South Bengara-II) Pte. Ltd., we relinquished our interest in the recently awarded South Bengara-II production sharing contract, onshore Indonesia. On May 18, 2009, we received repayment of an advance we had previously made to Adelphi in the amount of $95,000 in connection with the acquisition of the production sharing contract.

On September 10, 2009, the Company s subsidiary, Madisonville Midstream, LLC reached an agreement to sell certain idle equipment related to the plant to Gas Processors, Inc. for a sale price of $2.5 million. A nonrefundable deposit of $250,000 was received on September 10, 2009. The remaining balance of $2.25 million was received on September 30, 2009. Of the $2,500,000 sales proceeds, $1,125,000 was applied toward a reduction of the principal balance on the Bank of Oklahoma term loan.

Between August 3, 2009 and October 13, 2009, we entered into preferred stock purchase agreements for the private placement of 5,049,333 shares of Series B Preferred Stock for a purchase price of $0.75 per share and an aggregate investment, before offering costs, of $3,787,000. Significant rights and preferences attaching to the Series B Preferred Stock are described above.

Between August 3, 2009 and October 23, 2009, we issued promissory notes for total gross proceeds of $1,000,000 (net proceeds of $960,000). We issued to the note holders warrants exercisable to purchase 50,000 shares of our common stock. Each warrant is exercisable for a three year term to purchase one share of our common stock at a price of $1.00 per share. The issuance dates, maturity dates and interest rates for these promissory notes are as follows:

DATE OF NOTE	MATURITY DATE	INTEREST RATE	PRINCIPAL AMOUNT
08/13/09	08/30/10	10%	$ 100,000
08/21/09	08/30/10	10%	100,000
09/01/09	08/30/10	10%	30,000
09/16/09	08/30/10	10%	50,000

10/23/09	10/31/10	10%		720,000
			$	1,000,000

On September 11, 2009, our subsidiary, Redwood Energy Production, L.P. filed an Original Petition for Declaratory Judgment against Devon Energy Production Company (Devon) regarding certain overriding royalty interests and related revenue amounts claimed by Devon. We have previously accrued all amounts owed pursuant to these overriding royalty interests as royalty owners payable. In the opinion of management based on consultation with legal counsel, these proceedings are not expected to have a material adverse effect on our financial condition or results of operations.

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On February 15, 2010, we entered into a new lease for our principal executive office to be located at 150 California Street, Suite 600, San Francisco, CA 94111. The terms of the lease provide for an eighty-four (84) month term. Minimum annual rentals due under this agreement are as follows:

2010		95,223*
2011		145,635
2012		149,836
2013		154,037
2014		158,238
2015		162,439
2016		166,640
2017		56,013
Total	$	1,088,061

*The lease provides that rent for the first five months of the lease term totaling $59,514 shall be abated provided we are not in default during the term of the lease.

On February 26, 2010, we sold our entire working interest in our Alaskan leases to Linc Energy (Alaska) Inc. (Linc). Linc is a wholly-owned subsidiary of Linc Energy Ltd., an Australian-based company publicly traded on the Australian Stock Exchange.

Linc will acquire all of the Alaskan Leases for the following consideration:

a. A cash payment of $1.0 million will be deposited by Linc in an escrow account, to be released to us upon approval of the assignments of the Alaskan leases to Linc.

b. In addition, we will receive a $4.0 million payment from the first 75% of 8/8ths of the proceeds from any oil and gas production from the Alaskan leases.

c. After we have received the $4.0 million payment specified in paragraph (b) above, we will thereafter receive an overriding royalty interest of 10% of 8/8ths in and to the Alaskan leases issued by the State of Alaska and the Alaska Mental Health Trust (which comprise over 99% of the Alaskan Leases), and an overriding royalty interest of 7% of 8/8ths in and to the Alaskan Leases issued by Cook Inlet Region, Inc. on conventional oil and gas production and coal bed methane production.

d. Linc has agreed to pay all of the costs of maintaining the Alaskan leases at least through the end of the primary terms thereof.

e. Following the lessors approval of the assignments of the Alaskan leases into Linc, Linc will diligently commence and prosecute the drilling of the Frontier Spirit #1 exploration well to evaluate a conventional oil and gas prospect identified and developed by us.

Liquidity and Capital Resources

Our cash balance at December 31, 2009 was $2,429,891 compared to a cash balance of $770,779 at December 31, 2008. The change in our cash balance is summarized as follows:

Cash balance at December 31, 2008	$	770,779
Sources of cash:		
Cash provided by disposition of equipment		2,500,000
Cash provided by financing activities		5,280,019
Total sources of cash including cash on hand		8,550,798
Uses of cash:		
Cash used by operating actives		(4,773,997)
Cash used in investing activities:		
Oil and natural gas property expenditures		(758,006)
Gas processing plant		(588,904)
Total uses of cash		(6,120,907)
Cash balance at December 31, 2009	$	2,429,891

We had a working capital deficit of $1,174,225 and $2,151,652 at December 31, 2009 and December 31, 2008, respectively. Our working capital increased during year ended December 31, 2009 due primarily to funds raised from private placement from Series B preferred stock.

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We have historically financed our business activities through December 31, 2009 principally through issuances of preferred stocks, issuances of common shares, promissory notes, common share purchase warrants in private placements and an initial public offering. These financings are summarized as follows:

	Years Ended			
	December 31, 2009		December 31, 2008	
Proceeds from sale of common shares and warrant exercises, net	$		$	375,000
Proceeds from sale of Preferred Series B, net		5,448,602		
Payment on preferred dividends		(68,583)		
Repayments of promissory notes		(1,825,000)		
Proceeds from promissory notes		1,897,000		1,050,000
Payment of loan fee		(40,000)		(6,000)
Repayment of related party note		(132,000)		
Net option exercise				
Net cash provided by financing activities	$	5,280,019	$	1,419,000

The net proceeds of our equity and note financings have been primarily invested in oil and natural gas properties totaling $758,006, and $5,569,417 for the years ended December 31, 2009 and 2008, respectively.

On December 31, 2008, we acquired the gas treatment plant from MGP for $10,707,982 in combination of cash, debt and common stock. The Company assumed $7,697,847 of Madisonville Gas Processing LP s (MGP) bank debt related to the Company s acquisition of the Madisonville Gas Treatment Plant (the Plant) via a (i) $1 million cash payment applied directly towards debt principal reduction, and (ii) a refinancing by GeoPetro of the $6,697,847 remaining balance in the form of a 3 year Amended and Restated Term Loan Agreement with the lender, Bank Oklahoma (BOK). The terms of the three year loan provide for minimum quarterly principal payments of $150,000 and interest payable quarterly in arrears at prime plus 4% or, Libor plus 5.5%, at the option of the Company. Additional principal will be payable upon GeoPetro meeting certain net operating cash flow thresholds during the three year term of the loan. The loan is secured by a first lien on the Madisonville Midstream Plant and all of the Company s proved natural gas reserves located at the Madisonville Project. In addition, GeoPetro has agreed to a pay, at the time the loan is repaid in full, a loan origination fee of (i) $60,000 for any period during the three year term during which the loan principal remains outstanding. There is no prepayment penalty. The Amended and Restated Term Loan Agreement, as further amended, contains customary affirmative and negative covenants including restrictions on incurring additional debt and requiring that the Company maintain a minimum tangible net worth of at least $18,000,000.

On December 31, 2008, we issued 1.5 million shares of common stock pursuant to an asset purchase agreement related to the acquisition of the Madisonville Midstream Gas Treatment Plant and related gas gathering pipelines and related facilities from Madisonville Gas Processing, LP.

During December 2008, GeoPetro raised $1,050,000 by issuing promissory notes to accredited investors, each having the following terms: (i) 8% annual simple interest payable quarterly in arrears, (ii) principal and any unpaid outstanding interest shall be payable at the end of three years, (iii) subordinated to the BOK loan and (iv) be unsecured. Each note purchaser also received warrants to purchase one share of GeoPetro common stock for $1.00 per share, exercisable for three years. One warrant was received for each $10 in face amount of notes purchased (a total of 105,000 warrants exercisable to purchase 105,000 shares of common stock). GeoPetro also reissued 15,000 warrants at $1.00 per share to be exercised for three years.

We raised $850,000 in convertible notes that were converted into our Series B Preferred Stock on April 30, 2009, an additional $2,181,710 in our Series B Preferred Stock, and issued $1,177,000 in promissory notes. On September 30, 2009, we

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completed the sale of certain idle equipment from our natural gas processing plant for total cash proceeds of $2.5 million. During October 2009, we issued a promissory note for total gross proceeds of $720,000 (net proceeds of $701,383) and issued an additional 3,401,996 shares of Series B Preferred Stock for total gross proceeds of $2,551,500.

Our current cash and cash equivalents and anticipated cash flow from operations may not be sufficient to meet our working capital, capital expenditures and growth strategy requirements for the foreseeable future. See Outlook for 2010 for a description of our expected capital expenditures for 2010. If we are unable to generate revenues necessary to finance our operations over the long-term, we may have to seek additional capital through the sale of our equity or borrowing. As noted in Recent Developments, we periodically borrow funds pursuant to promissory notes to finance our activities.

As discussed in the Outlook for 2010 , we are forecasting capital expenditures of $3.5 million during 2010. We will need to obtain adequate sources of cash to fund our anticipated capital expenditures through the end of 2010 and to follow through with plans for continued investments in oil and gas properties. Our success, in part, depends on our ability to generate additional financing and farmout certain of our projects. Additionally, as a result of the 2009 economic downturn, the Company may have difficulty raising sufficient funds to meet our projected funding requirements. See Item 1A.- Risk Factors Risks Related to Our Business .

Since our inception, we have participated as a working interest owner in the acquisition of undeveloped leases, seismic options, lease options and foreign concessions and have participated in seismic surveys and the drilling of test wells on our undeveloped properties. Further leasehold acquisitions, drilling and seismic operations are planned for 2010 and future periods. In addition, exploratory and development drilling is scheduled during 2010 and future periods on our undeveloped properties. It is anticipated that these exploration activities together with others that may be entered into will impose financial requirements which will exceed our existing working capital. We may raise additional equity and/or debt capital, and we may farm-out certain of our projects to finance our continued participation in planned activities. However, if additional financing is not available, we may be compelled to reduce the scope of our business activities. If we are unable to fund planned expenditures, it may be necessary to:

1. farmout our interest in proposed wells;

2. sell a portion of our interest in prospects and use the sale proceeds to fund our participation for a lesser interest;

3. reduce general and administrative expenses;

4. forfeit our interest in wells that are proposed to be drilled .

Outlook for 2010 Capital

Depending on capital availability, we are forecasting capital spending of up to approximately $3,528,000 during the year 2010, allocated as follows:

1. Madisonville Project, Madison County, Texas Approximately $3,028,000 may be expended in the Madisonville Field area as follows: $1,433,000 million for capital maintenance and repair on new gas treatment plant; $945,000 toward the fracture stimulation and hook up costs of the Wilson Well; and $650,000 for the Mitchell well workover.

2. California Approximately $500,000 to be utilized for land and permitting costs.

We may, in our discretion, decide to allocate resources towards other projects in addition to or in lieu of, those listed above should other opportunities arise and as circumstances warrant. We currently do not have sufficient working capital to fund all of the capital expenditures listed above. We may, in our discretion, fund the foregoing planned expenditures from operating cash flows, asset sales, potential debt and equity issuances and/or a combination of all four. The Madisonville Project forecasted capital expenditures will play an important part in the Company achieving our 2010 cash flow projections. See Liquidity and Capital Resources.

We expect commodity prices to be volatile, reflecting the current supply and demand fundamentals for North American natural gas and world crude oil. Political and economic events around the world, which are difficult to predict, will continue to influence both oil and gas prices. Significant price changes for oil and gas often lead to changes in the levels of drilling activity which in turn lead to changes in costs to explore, develop and acquire oil and gas reserves. Significant change in costs could affect the returns on our capital expenditures. Higher crude prices could also help keep natural gas prices high by keeping alternative fuels, such as heating oil and residual fuel, expensive.

Income Taxes

As of December 31, 2009, GeoPetro had net operating loss (NOL) carryforwards of approximately $31,991,000 for federal income tax purposes which begin to expire in 2017. If the Company were to experience a change in ownership under Section 382, the Company may be limited in its ability to fully utilize its net operating losses.

However, in accordance with ASC 718 (formerly SFAS 123(R)), a deferred tax asset has not been recognized for the portion of the net operating loss carryforwards that is attributable to excess tax deductions associated with the exercise of stock options which do not reduce income taxes payable. Accordingly, approximately $3,536,000 of GeoPetro s federal NOL has not been benefited for financial statement purposes as it relates to excess tax deductions that have not reduced income taxes payable. The benefit of these excess tax deductions will not be recognized for financial statement purposes until the related deductions reduce income taxes payable.

The Company also has approximately $10,258,000 of California net operating losses and approximately $551,000 of Alaska net operating losses which begin to expire in 2010 and 2026, respectively. In accordance with ASC 718, a portion of the state NOLs has similarly not been benefited for financial statement purposes as it relates to excess tax deductions which have not resulted in the reduction of income taxes payable. The benefit of such excess tax deductions will not be recognized for financial statement purposes until the related deductions reduce state income taxes payable.

In addition, the Company has approximately $334,000 of carryforward credits in Texas, a portion of which may be utilized each year against Texas Margin Tax liability through 2027.

A significant change in our ownership may limit our ability to use these NOL carryforwards. ASC 740, Accounting for Income Taxes (formerly Statement of Financial Accounting Standards No. 109), requires that the tax benefit of such net operating loss be recorded as an asset. At December 31, 2009, we had net deferred tax assets of approximately $12,836,000 related to the NOL and

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other temporary differences. We have recorded a full valuation allowance of $12,836,000 at December 31, 2009 due to uncertainties surrounding the realizability of the deferred tax asset.

Off Balance Sheet Arrangements

From time to time, we may enter into off-balance sheet arrangements and transactions that can give rise to off-balance sheet obligations. As of December 31, 2009, our off-balance sheet arrangements and transactions include operating lease agreements and gas transportation commitments. We do not believe that these arrangements are reasonably likely to materially affect our liquidity or availability of, or requirements for, capital resources.

Financial Instruments

We currently have no natural gas price financial instruments or hedges in place. Similarly, we have no financial derivatives. Our natural gas marketing contracts use spot market prices. Given the uncertainty of the timing and volumes of our natural gas production this year, we do not currently plan to enter into any long term fixed-price natural gas contracts, swap or hedge positions, other gas financial instruments or financial derivatives in 2009.

Impact of Inflation & Changing Prices

As the following table illustrates, average sales prices of natural gas have changed in the past three years. This has led to changes in revenues and earnings from operations:

	For the Year Ended December 31,	
	2009 (1)	2008 (2)
Average Sales Prices per Mcf	$ 3.19	$ 4.82
Net Production Volume Mcf	1,278,434	1,275,445
Revenues	$ 4,077,355	$ 6,152,542
Loss from Operation	$ (26,567,746)	$ (252,061)

(1) Includes $20,843,305 impairment expense

(2) Includes $69,856 impairment expense

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We are highly dependent upon natural gas pricing. A material decrease in current and projected natural gas prices could impair our ability to raise additional capital on acceptable terms. Likewise, a material decrease in current and projected natural gas prices could also impact our revenues and cash flows. This could impact our ability to fund future activities.

Changing prices have had a significant impact on costs of drilling and completing wells, particularly in the Madisonville Field area where we are currently the most active. The estimated cost of drilling and completing a Rodessa formation well at approximately 12,300 feet of depth has increased from $3.0 million in 2001 to $4.2 million in 2009 due to higher costs associated with tubular goods, well equipment, and day rates for drilling contracts, among other factors. These higher costs have impacted and will continue to impact our income from operations in the form of higher depletion expense.

Critical Accounting Estimates

Our consolidated financial statements have been prepared by management in accordance with U.S. GAAP.

The preparation of consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Management believes the most critical accounting policies that may have an impact on our financial results relate to the accounting for oil and gas properties. Amortization, abandonment costs and full cost ceiling limitation write-downs are all based on numerous estimates, many of which are beyond management s control. Reserves valuation is central to much of the accounting for an oil and gas company as described below.

Significant accounting policies are contained in Note 2 to the consolidated financial statements. A summary of unaudited supplementary oil and gas reserve information is contained in Note 12 to the consolidated financial statements.

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The following discusses the accounting estimates that are critical in determining the reported financial results:

Oil and Gas Properties We follow the full cost method of accounting for oil and gas producing activities as prescribed by U.S. GAAP and, accordingly, capitalize all costs incurred in the acquisition, exploration, and development drilling of proved oil and gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and lease rentals. All general corporate costs are expensed as incurred. In general, sales or other dispositions of oil and gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded. Amortization of proved oil and gas properties is computed on the units of production method based on all proved reserves on a country by country basis. Unproved oil and gas properties are assessed for impairment either individually or on an aggregate basis. The net capitalized costs of proved oil and gas properties (full cost ceiling limitation) are not to exceed their related estimated future net revenues discounted at 10%, and the lower of cost or estimated fair value of unproved properties, net of tax considerations.

Reserves We engage independent petroleum engineering consultants to evaluate our reserves. Reserves, future production profiles, and net revenues are estimated by independent professional reservoir engineering firms. While we engage qualified reservoir engineering firms, their estimates are inherently uncertain, involve numerous assumptions that may not be realized, and predict asset values that may not be indicative of the true market value of the assets evaluated. As a result of the inherent uncertainties and changing technical and economic assumptions, reserve estimates are subject to revisions that can materially impact our results.

Stock Based Compensation The Company has a stock- based compensation plan that allows employees to purchase common shares of the Company. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted under the plan are generally fully exercisable within five years and expire five to ten years after the grant date. We measure and record stock-based awards to directors, employees and consultants based on the grant-date fair value, determined using the Black-Scholes option pricing model with assumptions for: risk free interest rates, expected dividend yield, expected life of the option, and the expected volatility. We record the compensation expense ratably over the requisite service period defined in the award. The Company recorded $403,963 and $268,723 of stock-based employee compensation for the twelve months ended December 31, 2009 and 2008, respectively.

Recently Issued Accounting Pronouncements

Effective January 1, 2009, we adopted ASC 260-10 (formerly Staff Position No. EITF 03-6-1), Determining whether Instruments Granted in Share-Based Payment Transactions are Participating Securities, which provides that unvested share-based payment awards that contain non-forfeitable rights to dividend or dividend equivalents (whether paid or unpaid) are participating securities, and, therefore need to be included in the earnings allocation in computing earnings per share under the two-class method. We adopted the provisions of this standard on January 1, 2009, with no significant impact on our financial statements.

Effective January 1, 2009, we adopted ASC 815-10 (formerly Statement of Financial Accounting Standards (SFAS) 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement 133*), which amends and expands the disclosure requirements with the intent to provide users of financial statements with an enhanced understanding of (i) how and why an entity uses derivative instruments; (ii) how derivative instruments and the related hedged items are accounted for; and (iii) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. We adopted the provisions of this standard on January 1, 2009, with no significant impact on our financial statements.

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In June 2009, the FASB issued ASC 105-10 (formerly SFAS No. 168), *Accounting Standards CodificationTM and the Hierarchy of Generally Accepted Accounting Principles*. The FASB Accounting Standards CodificationTM (the Codification) has become the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in accordance with Generally Accepted Accounting Principles (GAAP). All existing accounting standard documents are superseded by the Codification and any accounting literature not included in the Codification will not be authoritative. Rules and interpretive releases of the SEC issued under the authority of federal securities laws, however, will continue to be the source of authoritative generally accepted accounting principles for SEC registrants. Effective September 30, 2009, all references made to GAAP in our consolidated financial statements will include the new Codification numbering system along with original references. The Codification does not change or alter existing GAAP and, therefore, will not have an impact on our financial position, results of operations or cash flows.

In December 2008, the SEC issued the final rule on the Modernization of Oil and Gas Reporting. This SEC ruling revises its oil and gas reserves reporting requirements effective for fiscal years ending on or after December 31, 2009, with early adoption prohibited. These revisions by the SEC are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. These changes include:

- Modifying prices used to estimate reserves for SEC disclosure purposes to a 12-month average price instead of a single-day, period-end price.
- Requiring certain additional disclosures around proved undeveloped reserves, internal controls used to ensure objectivity of the estimation process, and qualifications of those preparing and/or auditing the reserves.
- Expanding the definition of oil and gas reserves and providing clarification of certain concepts and technologies used in the reserve estimation process.
- Allowing optional disclosure of probable and possible reserves and permitting optional disclosure of price sensitivity analysis.
- We are now required to file the report of any third party used to prepare or audit reserves our estimates.

In addition, in January 2010, FASB issued Account Standards Update (the Update) 2010-03, Oil and Gas Reserve Estimation and Disclosures, to provide consistency with the new reserve rules. The Update amends existing standards to align the reserves calculation and disclosure requirements under GAAP with the requirements in the SEC s reserve rules. We adopted the new standards effective December 31, 2009. The new standards are applied prospectively as a change in estimate.

Application of the new reserve rules resulted in the use of a lower natural gas price at December 31, 2009 than would have resulted under the previous rules. As a result, the new pricing methodology rules resulted in a lower net present value (PV-10) of economically producible reserves. The new SEC rules require that reserve calculations be based on the un-weighted average first-day-of-the-month prices for the prior twelve months, as contrasted with the previous method which utilized period end prices. The prices under the new rules were $3.11 per Mcf for natural gas adjusted for energy content, quality and basis differentials. Under the new rules, this resulted in a ceiling test write-down of $19.8 million associated with the US full cost pool. Had we used the price prevailing on December 31, 2009 of $5.45 per Mcf for natural gas, no ceiling test write-down would have been recorded.

Use of new 12-month average pricing rules at December 31, 2009 also resulted in a decrease in economically producible proved reserves of approximately 1.03 Bcf. Use of the old year-end prices rules would have resulted in a decrease in proved reserves of approximately 0.53 Bcf at December 31, 2009. Therefore, the total impact of the new price methodology rules resulted in negative reserves revisions of 0.5 Bcf.

Because we use quarter-end reserves and add back current production to calculate quarterly depletion, depreciation and amortization expense, or DD&A, adoption of these new standards had an impact on DD&A for the fourth quarter of 2009. We estimate the impact of using the unweighted, arithmetic average on the closing price on the first day of each month for the 12-month period prior to December 31, 2009, as required by the new reserve rules, instead of year-end commodity prices, to be an increase in DD&A for the fourth quarter of 2009 of approximately $84,423.

On June 30, 2009, we adopted ASC 855-10 (formerly SFAS No. 165) *Subsequent Events*. ASC 855-10 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Specifically, ASC 855-10 sets forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements, and the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. The adoption of ASC 855-10 had no impact on our results, cash flow or financial position as management already followed a similar approach prior to the adoption of this standard.

In January 2010, the Financial Accounting Standards Board issued amendments to Fair Value Measurements and Disclosures under ASC Topic 820. Effective for our 2010 financial statements, this guidance provides for disclosures of significant transfers in an out of Levels 1 and 2. In addition, the guidance clarifies existing disclosure requirements regarding inputs and valuation techniques as well as the appropriate level of disaggregation for fair value measurements and disclosures. Effective for our 2011 financial statements, this guidance provides for disclosures of activity on a gross basis within Level 3 reconciliation.

Risks and Uncertainties

There are a number of risks that face participants in the U.S., Canadian and international oil and natural gas industry, including a number of risks that face us in particular. Accordingly, there are risks involved in an ownership of our securities. See Risk Factors for a description of the principal risks faced by us.

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

We are exposed to market risks arising from fluctuating prices of crude oil, natural gas and interest rates as discussed below.

Commodity Risk. Our major commodity price risk exposure is to the prices received for our natural gas production. Realized commodity prices received for our production are the spot prices applicable to natural gas in the East Texas region. Prices received for natural gas are volatile and unpredictable and are beyond our control.

Currency Translation Risk. Because our revenues and expenses are primarily in U.S. dollars, we have little exposure to currency translation risk, and, therefore, we have no plans in the foreseeable future to implement hedges or financial instruments to manage international currency changes.

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Hedging. We did not enter into any hedging transactions during the year ended December 31 2009.

Item 8. ***Financial Statements and Supplementary Data***

The reports of our independent registered public accounting firms and our consolidated financial statements and supplemental information required to be filed under Item 8 of Form 10-K are presented beginning on Page F-1 of this Form 10-K.

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

None.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our President, Chief Executive Officer and Chairman and our Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2009. Based on this evaluation, we have concluded that, as of December 31, 2009, our disclosure controls and procedures were effective, in that they ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is (1) recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and (2) accumulated and communicated to our management, including our President and Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Internal control over financial reporting

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, we have included a report of management s assessment of the design and effectiveness of our internal controls as part of this annual report on Form 10-K for the fiscal year ended December 31, 2009. This annual report does not include an attestation report of the company s registered public accounting firm regarding internal control over financial reporting. Management s report was not subject to attestation by the Company s registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit the company to provide only management s report in this annual report. Management s report shall not be deemed to be filed for purposes of Section 18 of the Exchange Act or otherwise subject to the liabilities of that section.

No changes to our internal control over financial reporting occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act).

Item 9B. ***Other Information***

None.

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PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information required by this item is incorporated by reference from our definitive proxy statement relating to our 2009 Annual Meeting of Shareholders, to be filed on or before April 30, 2010, the 2010 proxy statement.

Item 11. ***Executive Compensation***

The information required by this item is incorporated by reference from our 2010 proxy statement.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters***

The information required by this item is incorporated by reference from our 2010 proxy statement.

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

The information required by this item is incorporated by reference from our 2010 proxy statement.

Item 14. ***Principal Accountant Fees and Services***

The information required by this item is incorporated by reference from 2010 proxy statement.

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PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) The following documents are filed as part of this report

2. All other schedules are omitted because they are not applicable, not required or the required information is included in the consolidated financial statements or related notes.

3. A list of exhibits filed or furnished with this report on Form 10-K (or-incorporated by reference to exhibits previously filed or furnished by GeoPetro) is provided in the Exhibit Index immediately following the financial statements in this report.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 31, 2010.

GEOPETRO RESOURCES COMPANY

By:	/s/ Stuart J. Doshi Stuart J. Doshi Chairman of the Board of Directors, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 31, 2010.

Signature	Title	Date
/s/ Stuart J. Doshi Stuart J. Doshi	Chairman of the Board, President and Chief Executive Officer	March 31, 2010
/s/ David V. Creel David V. Creel	Vice President of Exploration and Director	March 31, 2010
/s/ J. Chris Steinhauser J. Chris Steinhauser	Chief Financial Officer and Principal Accounting Officer	March 31, 2010
/s/ J. Chris Steinhauser J. Chris Steinhauser	Director	March 31, 2010
/s/ Jeffrey Friedman Jeffrey Friedman	Director	March 31, 2010
/s/ Thomas D. Cunningham Thomas D. Cunningham	Director	March 31, 2010
/s/ David G. Anderson David G. Anderson	Director	March 31, 2010
/s/ Nick DeMare Nick DeMare	Director	March 31, 2010

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GLOSSARY OF OIL AND NATURAL GAS TERMS

In this report, unless the context otherwise requires, the following terms shall have the indicated meanings. A reference to an agreement means the agreement as it may be amended, supplemented or restated from time to time.

1933 Act means the United States *Securities Act* of 1933, as amended.

BOK means the Bank of Oklahoma N.A.

Bengara II PSC means the PSC dated December 4, 1997 between C-G Bengara and Pertamina.

Bengara Block means the contract area in the Indonesian province of East Kalimantan designated as the Bengara (II) PSC Block.

BP Migas means Badan Pelaksana Minyak Dan Gas Muni, a new executive board established by the government of Indonesia in 2002 for oil and gas upstream operations and an implementing body created to assume the role of Pertamina s regulatory functions and responsibilities in managing oil and gas contractors.

CBM means coal bed methane, which is methane found in coal seams. It is produced by non-traditional means, and therefore, while it is sold and used the same as traditional natural gas, its production is different. CBM is generated either from a biological process as a result of microbial action or from a thermal process as a result of increasing heat with depth of the coal. Often a coal seam is saturated with water, with methane held in the coal by water pressure.

C-G Bengara means Continental-GeoPetro (Bengara II) Ltd., a British Virgin Islands corporation owned 12% by GeoPetro.

CG Xploration means CG Xploration Inc., a Delaware corporation owned 50% by GeoPetro.

CNPC means CNPCHK (Indonesia) Limited. CNPC is a wholly owned subsidiary of CNPC (Hong Kong) Limited, a publicly held company based in Hong Kong where its shares trade on the Hong Kong Stock Exchange under the listing number 0135.HK.

Company or **GeoPetro** means GeoPetro Resources Company, a corporation incorporated under the laws of the State of California and its wholly-owned subsidiaries.

Condensate means a low-density, high-API gravity liquid hydrocarbon product that is generally produced in association with natural gas. Condensate is mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

Continental means Continental Energy Corporation.

CRA means the Canada Revenue Agency.

Earning Obligation means $18.7 million paid by CNPC into a special joint venture account at a Hong Kong international bank, which funds are under joint signature control of CNPC ourselves and Continental, and has been expended to pay for 2007 exploration drilling in the Bengara II PSC area.

EIA means the United States Energy Information Administration.

EP 408 means the approximately 201,000 gross (52,675 net) acre permit area including the Whicher Range gas field in the South Perth basin of Western Australia designated as Exploration Permit 408 which we transferred to an unrelated party in June 2007.

Proved Properties means those properties that are producing oil or gas or on which, based on known geological and engineering data, oil and gas reserves are reasonably certain to exist.

Fannin Well means the Angela Farris Fannin No. 1 well located at the Madisonville Field.

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Farmout means an agreement whereby a third party agrees to pay for the drilling of a well on one or more of GeoPetro s properties in order to earn an interest therein with GeoPetro retaining a residual interest in such properties.

Flow-Through Share means a share of common stock issued as a flow-through share within the meaning of Canadian tax law.

Gateway means Gateway Processing Company, a Texas corporation that has constructed pipeline facilities at the Madisonville Field.

GeoPetro Alaska means GeoPetro Alaska LLC, an Alaska limited liability company, which is a wholly-owned subsidiary of GeoPetro.

GeoPetro Canada means GeoPetro Canada Ltd., an Alberta corporation, which is a wholly-owned subsidiary of GeoPetro.

Hanover means Hanover Compression Limited Partnership, a Delaware limited partnership that has constructed and previously operated treatment facilities at the Madisonville Field.

Hanover Agreement means, collectively, the First Amended and Restated Master Agreement, dated as of September 12, 2002 among Redwood, Hanover and Gateway, as amended, providing for the processing of natural gas from the Madisonville Field, and the agreements related thereto, which agreements were in effect prior to August 2005.

LPG means liquefied petroleum gas.

Madisonville Field means the Madisonville (Rodessa) field in Madison County, Texas.

Madisonville Midstream LLC means Madisonville Midstream LLC, a Texas limited liability company, which is a wholly-owned subsidiary of Redwood Energy Production, and which is 100% owned, directly or indirectly, by GeoPetro.

Madisonville Project means the oil and natural gas exploration, development and production project at the Madisonville Field.

Magness Well means the UMC Ruby Magness No. 1 well located at the Madisonville Field.

Makapan Gas Field means the Makapan gas field in East Kalimantan, Indonesia.

MGP means Madisonville Gas Processing, LP, a Colorado Limited Partnership that has purchased from Hanover and currently operates the treatment facilities at the Madisonville Field, and is jointly owned by JPMorgan Partners and Bear Cub Investments LLC.

MGP Agreement means, collectively, the Termination and Release Agreement, Madisonville Field Development Agreement, Gas Purchase Contract between Redwood LP as Seller, and MGP as Buyer, Escrow Agreement and Dedication Agreement, all effective as of August 1, 2005 among Redwood LP, MGP, Gateway and Gateway Pipeline Company, providing for the termination of the Hanover Agreement, the expansion of the treatment facilities and the provision of the gathering, processing, transportation and sale of natural gas from the Madisonville Field.

Mitchell Well means the Mitchell No. 1 well located at the Madisonville Field.

Pertamina means Perusahaan Pertambangan Minyak Dan Gas Bumi Negara, the previous Indonesian state-owned oil and natural gas company established in 1971 which had exclusive authority to explore, drill for, and produce oil and natural gas minerals in Indonesia. In accordance with the new Indonesian Oil and Gas Law, its corporate form has been changed to become a state-owned limited liability company established under Indonesian Company Law, and all rights and obligations of Pertamina under existing PSCs shall pass to BP Migas.

Proved developed oil and gas reserves means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved developed nonproducing reserves means reserves expected to be recovered from zones behind casing in existing wells.

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Proved oil and gas reserves means estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or a conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following:

(A) oil that may become available from known reservoirs but is classified separately as indicated additional reserves ;

(B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

(C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

(D) crude oil, natural gas, and natural gas liquids that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved undeveloped reserves means reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates, for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

PSC means a production sharing contract, being a contract with Pertamina whereby Pertamina contracts with a petroleum company to explore for, develop and extract petroleum substances from a particular license area, on Pertamina s behalf, at the risk and expense of the petroleum company, in exchange for a share of the production.

Redwood means Redwood Energy Company, a Texas corporation, which is a wholly-owned subsidiary of GeoPetro and which is the general partner of, and holds a 5% interest in, Redwood LP.

Redwood LP means Redwood Energy Production, L.P., a Texas limited partnership, the sole limited partner of which is GeoPetro and which is 100% owned, directly or indirectly, by GeoPetro.

Rodessa Formation means the geological formation at the Madisonville Field existing at a depth of approximately 12,000 feet.

Seismic means data collected that uses reflected seismic waves to produce images of the Earth s subsurface. The method requires a controlled seismic source of energy, such as dynamite or a specialized air gun. By noting the time it takes for a reflection to arrive at a receiver, it is possible to estimate the depth of the feature that generated the reflection.

Series A Stock means the preferred stock of GeoPetro designated as Series A preferred stock, all of which converted to GeoPetro s common stock on March 30, 2006.

Series AA Stock means the preferred stock of GeoPetro designated as Series AA preferred stock, as described under Description of Share Capital .

Series B Stock means the preferred stock of GeoPetro designed as Series B preferred stock, as described under Description of Share Capital .

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South Texas GeoPetro means South Texas GeoPetro, LLC., a Texas limited liability company, the sole limited partner of which is GeoPetro and which is 100% owned, directly or indirectly, by GeoPetro.

Tertiary Sandstones means sandstones which were deposited during a geologic time period ranging from 2 to 63 million years ago.

TSX means the Toronto Stock Exchange.

Unproved Properties means properties not yet evaluated through exploration and drilling as to whether or not they have proved reserves.

U.S. GAAP means the accounting principles generally accepted in the United States.

Wilson Well means the Wilson No. 1 well located at the Madisonville Field.

Working interest means the percentage of undivided interest held by a party in the oil and/or natural gas or mineral lease granted by the mineral owner, which interest gives the holder the right to work the property (lease) to explore for, develop, produce and market the leased substances.

ABBREVIATIONS AND CONVERSIONS

In this report, the following abbreviations have the meanings set forth below:

API	American Petroleum Institute
bbl and bbls	barrel and barrels, each barrel representing 34.972 Imperial gallons or 42 U.S. gallons
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent converting 6 mcf of natural gas to one barrel of oil equivalent and one barrel of natural gas liquids to one barrel of oil equivalent. Measures of boes may be misleading, particularly if used in isolation. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead, but is a commonly used industry benchmark.
boe/d	barrels of oil equivalent per day
degree API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28 degree API or higher is generally referred to as light crude oil.
LPG	liquefied petroleum gas
mbbls	one thousand barrels
mboe	one thousand barrels of oil equivalent
mcf	one thousand cubic feet
mcf/d	one thousand cubic feet per day
mmbbls	one million barrels
MMBTU	one million British Thermal Units
MMcf	one million cubic feet
MMcf/d	one million cubic feet per day
NGLs	natural gas liquids
Psig	Pounds per square inch gauge
TCF	trillion cubic feet

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GEOPETRO RESOURCES COMPANY

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance to management and our board of directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2009. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control - Integrated Framework.* Based on our assessment, we believe that as of December 31, 2009, our internal control over financial reporting was effective based on those criteria. This annual report does not include an attestation report of the Company s registered public accounting firm regarding internal control over financial reporting. Management s report was not subject to attestation by the Company s registered public accounting firm pursuant to temporary rules of the Securities and exchange Commission that permit the Company to provide only management s report in this annual report.

By:	/s/ Stuart J. Doshi	By:	/s/ J. Chris Steinhauser
	Stuart J. Doshi		J. Chris Steinhauser
	President, Chief Executive Officer and Chairman		Chief Financial Officer

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders

GeoPetro Resources Company

We have audited the consolidated balance sheets of GeoPetro Resources Company and subsidiaries (collectively, the Company) as of December 31, 2009 and 2008, and the related consolidated statements of operations, changes in shareholders equity and cash flows for each of the years then ended. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of GeoPetro Resources Company and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, the Company has changed its method of estimating its proved natural gas reserves and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements as of December 31, 2009.

We were not engaged to examine management s assessment of the effectiveness of GeoPetro Resources Company and subsidiaries internal control over financial reporting as of December 31, 2009, included in the accompanying Management s Report on Internal Controls and Financial Reporting and, accordingly, we do not express an opinion thereon.

*/s/ **HEIN** & ASSOCIATES LLP*

Dallas, Texas

March 31, 2010

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GEOPETRO RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,429,891	$ 770,779
Trade accounts receivable oil and gas sales	473,944	4,266
Accounts receivable other	8,658	35,107
Prepaid expenses	132,238	212,938
Total current assets	3,044,731	1,023,090
Oil and gas properties, at cost (full cost method):		
Unproved properties	8,411,773	10,500,498
Proved properties	51,194,852	48,346,939
Gas processing plant	10,285,573	10,707,982
Less accumulated depletion, depreciation and impairment	(38,950,914)	(16,522,304)
Net oil and gas properties	30,941,284	53,033,115
Furniture, fixtures and equipment, at cost, net of depreciation	2,071	12,364
Other assets deposits and other noncurrent assets	16,127	7,436
Total Assets	$ 34,004,213	$ 54,076,005
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities:		
Trade payables	$ 950,097	$ 1,137,432
Current portion of long term notes payable	1,549,829	600,000
Interest payable	136,233	1,479
Dividends payable	110,462	
Production taxes payable	309,904	311,168
Other taxes payable	11,147	20,833
Royalty owners payable	1,151,284	1,103,830
Total current liabilities	4,218,956	3,174,742
Long Term Notes Payable	5,986,645	7,019,449
Asset Retirement Obligations	65,009	59,099
Total Liabilities	10,270,610	10,253,290
Commitments and Contingencies (Notes 1, 4, and 10)		
Shareholders Equity:		
Series B preferred stock, no par value; 7,523,000 shares authorized; 7,523,000 shares issued and outstanding at December 31, 2009. Liquidation preference of $5,642,250 and $0, respectively	5,448,602	
Common stock, no par value; 100,000,000 shares authorized; 34,284,646 shares issued and outstanding, respectively	53,397,733	53,397,733
Additional paid-in-capital	3,060,187	2,610,596
Accumulated deficit	(38,172,919)	(12,185,614)

Total shareholders equity		23,733,603		43,822,715
Total Liabilities and Shareholders Equity	$	34,004,213	$	54,076,005

See accompanying notes to these consolidated financial statements.

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GEOPETRO RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31, 2009	2008
Revenues:		
Oil and gas sales	$ 4,077,355	$ 6,152,542
Costs and expenses:		
Plant operating	4,832,548	
Lease operating	606,266	1,484,267
General and administrative	2,767,385	2,717,121
Net profits interest		579,941
Impairment of oil and gas properties	20,843,305	69,856
Depreciation and depletion	1,595,597	1,553,418
Total costs and expenses	30,645,101	6,404,603
Loss from operations	(26,567,746)	(252,061)
Other Income (Expense):		
Interest expense	(736,596)	(1,846)
Interest income	6,404	91,867
Gain on sale of equipment	1,488,687	
Total other income	758,495	90,021
Loss Before Taxes	(25,809,251)	(162,040)
Income tax (expense) benefit	991	(12,785)
Net Loss After Taxes	(25,808,260)	(174,825)
Preferred stock dividend		