IHS Inc.
Form 3
November 10, 2005

FORM 3

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

OMB APPROVAL	
OMB Number:	3235-0104
Expires:	January 31, 2005
Estimated average burden hours per response...	0.5

INITIAL STATEMENT OF BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

(Print or Type Responses)

1. Name and Address of Reporting Person *
Â THYSSEN BORNEMISZA CONTINUITY TRUST

(Last) (First) (Middle)

C/O IHS INC. 15 INVERNESS WAY EAST

(Street)

ENGLEWOOD,Â COÂ 80112

(City) (State) (Zip)

2. Date of Event Requiring Statement (Month/Day/Year)
11/10/2005

3. Issuer Name **and** Ticker or Trading Symbol
IHS Inc. [IHS]

4. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director __X__ 10% Owner
_____ Officer _____ Other
(give title below) (specify below)

5. If Amendment, Date Original Filed(Month/Day/Year)

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Beneficially Owned

1.Title of Security (Instr. 4)	2. Amount of Securities Beneficially Owned (Instr. 4)	3. Ownership Form: Direct (D) or Indirect (I) (Instr. 5)	4. Nature of Indirect Beneficial Ownership (Instr. 5)
Class A common stock	41,250,000 (1)	I (2)	See footnote (2)

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

SEC 1473 (7-02)

Persons who respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB control number.

Table II - Derivative Securities Beneficially Owned (*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 4)	2. Date Exercisable and Expiration Date (Month/Day/Year)	3. Title and Amount of Securities Underlying Derivative Security (Instr. 4)	4. Conversion or Exercise Price of Derivative	5. Ownership Form of Derivative Security:	6. Nature of Indirect Beneficial Ownership (Instr. 5)

	Date Exercisable	Expiration Date	Title	Amount or Number of Shares	Security	Direct (D) or Indirect (I) (Instr. 5)	
Class B common stock	Â (3)	Â (3)	Class A common stock	13,750,000	$ (4)	I (2)	See footnote (2)

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
THYSSEN BORNEMISZA CONTINUITY TRUST C/O IHS INC. 15 INVERNESS WAY EAST ENGLEWOOD,Â COÂ 80112	Â	Â X	Â	Â

Signatures

/s/ STEPHEN GREEN	11/10/2005
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 5(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Includes up to 16,692,250 shares of Class A common stock being sold pursuant to a prospectus contained in IHS Inc.'s registration statement on Form S-1 (Registration No. 333-122565) and 4,687,500 shares of Class A common stock being sold pursuant to an Amended and Restated Stock Purchase Agreement by and among Urpasis Investments Limited, Urvanos Investments Limited, IHS Inc., General Atlantic Partners 82, L.P., GAP Coinvestments III, LLC and GAP Coinvestments IV, LLC, dated October 6, 2005.

(2) The Thyssen-Bornemisza Continuity Trust is the indirect sole owner of Urvanos Investments Limited and Urpasis Investments Limited (the direct owners of the securities).

(3) Each share of Class B common stock is convertible at any time at the option of the holder into one share of Class A common stock. In addition, each share of Class B common stock shall convert automatically, without any action by the holder, into one share of Class A common stock upon the occurrence of certain events as described in IHS Inc.'s registration statement on Form S-1 (Registration No. 333-122565) in the section captioned "Description of Capital Stock--Common Stock--Conversion."

(4) Each share of Class B common stock is convertible into one share of Class A common stock.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *See* Instruction 6ne">*If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).**Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).
Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. ign:right;">

PART IV

Table of Contents

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 150 California Street, Suite 600, San Francisco, California, USA 94111. We maintain a website located at www.geopetro.com.

Inter-Corporate 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 247,218 gross (33,302 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. In February 2010, we sold our entire 100% working interest in approximately 122,000 acres in our Alaskan Cook Inlet Project for cash and certain retained royalties.

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. 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 2010. 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 and Magness wells are producing while Mitchell and the Wilson wells are shut-in awaiting workovers. 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.

Table of Contents

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, geophysical and engineering 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 farm-outs 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, 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.

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.

Table of Contents

As of December 2010, 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; and
- 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.

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

Table of Contents

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 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

Table of Contents

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.

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.

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 the sale of common and preferred stock in private placements, cash received from the issuance of debt instruments and cash received from the disposition of our interests in oil and gas properties. 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. As of December 31, 2010 all of our revenue is derived from one customer. The loss of this customer 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.

Table of Contents

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 14 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 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, 2010, we have gross capitalized costs totaling $69.2 million as proved and unproved oil and gas properties and gas processing plant whereas we have generated revenues of only $43 million since January 1, 2003 and revenues of only $3.1 million during the fiscal year ended December 31, 2010.

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, 2010 of $43.6 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. There can be no assurance that we will be able to accomplish the expansion and achieve a full treatment capacity of 68 MMcf/d.

Table of Contents

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.

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.

All of our natural gas revenues for the years ended December 31, 2010 and 2009 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.

Table of Contents

100% of our revenue is derived from sales to a single customer. The loss of this customer 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, 2010 and 2009 were derived from the Madisonville Project. During 2010, 100% of our revenues have been derived from sales to one customer, Luminant Energy Company, LLC. The loss of, or material nonpayment by this customer could impact the price we receive for our gas sold due to lessened competition. The loss of, or material nonpayment by the customer could result in a loss of revenue. Our customer 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, 2010 we have capitalized costs of $69.2 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 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 summary, 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

Table of Contents

condition. Our natural gas sales and revenues were $3,054,255 and $4,077,355 for the years ended December 31, 2010 and 2009, respectively. Future revenues could decline from those levels if our future drilling efforts are not successful. Furthermore, as of December 31, 2010 we have net capitalized costs totaling approximately $30 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 Alaska, 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 Alaskan, Canadian and Indonesian properties. With respect to our interests in Alaska, 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 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.

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 farm-out arrangements with unaffiliated third parties.

We have previously entered into, and may in the future enter into, farm-out 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 farm-out arrangements have been or may be diminished. Our opportunity to realize revenues and profits from properties which are successfully developed under farm-out 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:

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

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

(3) 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.

Table of Contents

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 farm-out 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.

The global financial markets have been experiencing extreme volatility 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, 2010 and our liquidity for the twelve months ended December 31, 2010. 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

Table of Contents

if there is further deterioration in financial markets and major 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 capitalized as proved and unproved oil and gas properties and gas processing plant as of December 31, 2010.

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.

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 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

Table of Contents

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 and (5) CEQA, the California Environmental Quality Act, which is a statute that requires state and local agencies to identify the significant environmental impacts of their actions and to avoid and mitigate these impacts, if feasible. 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 $71,510 as of December 31, 2010.

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 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.

Table of Contents

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;
- identify 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 and continued political unrest in the Middle East increase 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.

Table of Contents

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 $587,000 as of December 31, 2010, 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 or 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.

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

Table of Contents

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, 2010 our directors and officers beneficially own approximately 12% 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 2011 we will need to raise capital. Due to the tight credit markets and prolonged volatility 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 2011 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 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:

- 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.

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, 2011, 41,161,173 shares of our common stock are outstanding, 7,503,000 shares of our Series B Preferred stock are outstanding, 5,057,229 shares of our common stock are issuable upon exercise of warrants and 2,895,000 shares of our common stock are issuable upon exercise of options.

Table of Contents

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 may 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, a 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.

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;

Table of Contents

- 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 2011, 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***

Through April 30, 2010 our principal executive office was located at One Maritime Plaza, Suite 700, San Francisco, CA 94111. Effective May 1, 2010 our new principal executive office consisting of 4,201 square feet is located at 150 California Street, Suite 600, San Francisco, CA 94111.

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 Basin) and **California** (onshore San Joaquin basin); and

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

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

Table of Contents

- **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 3,793 gross and net acres of leases in the Rodessa Formation interval, as well as approximately 2,060 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. Current production is approximately 3.0 MMcf/d. In addition, we own a working interest in certain leases which cover depths below the Rodessa Formation.

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.

Table of Contents

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. 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). 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.

Table of Contents

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

On February 26, 2010, we sold our entire 100% working interest in approximately 122,000 acres onshore in the Cook Inlet region of Alaska (the Alaskan Leases). The position consists of two separate target areas, the Point MacKenzie Prospect and the Trading Bay Prospect. 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. The interests were purchased by 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.

In exchange for our 100% working interest in our Alaskan leases we received the following consideration:

- a cash payment of $1.0 million;
- a $4.0 million payment from the first 75% of 8/8ths of the proceeds from any oil and gas production from the underlying leases;
- subsequent to our receipt of the $4.0 million payment specified above, we will thereafter receive an over-riding royalty interest of 10% of 8/8ths in and to the leases issued by the State of Alaska and the Alaska Mental Health Trust on conventional oil and gas production and coal bed methane production; and

- Linc has agreed to pay all of the costs of maintaining the Alaskan Leases through the end of the primary lease terms.

On November 18, 2010, Linc completed the drilling of the LEA#1 exploration well in the Point Mackenzie Block of the Cook Inlet Basin in Alaska. A testing program to evaluate the potential for commercial gas production from the well will be undertaken. In addition to testing the LEA #1, Linc Energy has stated that it will prepare for phase two of its Alaskan natural gas drilling program in the Trading Bay Block leases which are located on the northwest side of the Cook Inlet approximately 70 miles from the site of LEA #1.

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 an estimated depth of approximately 8,000 feet. The LEA #1 well is located less than two miles from the Enstar 20 natural gas pipeline.

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 LEA #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.

Table of Contents

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 objectives are the Miocene Stevens formation and the Carneros member of the Temblor 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.

Subject to drilling permits, we expect that a well will be drilled, either by us or through a farm-out arrangement with a third party, to a depth of 15,000 to 18,000 feet in 2012 2013.

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-operated working interest in approximately 4,480 gross leased acres (1,493 net acres).

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 Kunlun Energy (formerly 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.

Table of Contents

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 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

25

Table of Contents

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.

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:

- 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;

- 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;

- 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; and

- 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 2011/2012 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.

Table of Contents

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 us and Continental. To date, CG Xploration has not completed any acquisitions.

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:

- initial cash consideration of $175,000 was received on November 19, 2007;

- 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

- 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

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, 2010 and 2009. MHA is a Denver based group of multiple 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 24 years of practical experience in petroleum engineering, with over 11 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 36 years of practical experience in petroleum geology, with over 26 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, 2010, our PUDs totaled 8.8 Bcf of natural gas.

- *PUD Locations* - 100% of our PUDs at year-end 2010 were associated with the Madisonville Field.

- *Development Costs*- Estimated future development costs relating to the development of PUDs are projected to be approximately $2.4 million and $4.2 million in 2011 and 2012 respectively.

- *Drilling Plans* - Our PUD development is scheduled in 2011 and 2012. Initial production from the PUD reserves is expected to begin in 2011.

Our estimated total net proved reserves of natural gas and oil as of December 31, 2010 and 2009, and the present values of estimated future net revenues attributable to those reserves as of those dates, are presented in the following tables.

Table of Contents

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, that 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 hydrocarbon 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 hydrocarbon 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.

The 2010 and 2009 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 simple arithmetic average of the natural gas price in effect on the first day of each month in 2010 and 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:

Table of Contents

	AS OF DECEMBER 31, 2010 (MMcf)	2009 (MMcf)
Proved developed producing	2,422	3,650
Proved developed non-producing	7,049	6,611
Proved undeveloped	8,837	8,371
Total	18,308	18,632

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 2010 & 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 the respective years to estimated annual future net 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, 2010		2009	
	(in thousands)			
Future cash inflows	$	65,988	$	50,652
Future production costs		(19,353)		(17,157)
Future development costs		(7,849)		(7,849)
Future income taxes				
Future net cash flows		38,786		25,646
10% annual discount		(9,684)		(6,005)
Standardized measure of discounted future net cash flows	$	29,102	$	19,641

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 price used for the December 31, 2010 and 2009 MHA Petroleum Consultants reserve reports is the simple arithmetic average of the natural gas price in effect on the first day of each month in 2010 and 2009 respectively. 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 un-weighted average price for natural gas at December 31, delivered at the Houston Ship Channel before any reductions for transportation and processing fees:

AVERAGE PRICE 2010 REPORT Gas ($/MMBtu)	AVERAGE PRICE 2009 REPORT Gas ($/MMBtu)
$ 4.03	$ 3.11

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, 2010. 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:

Table of Contents

Acreage Holdings	Undeveloped acreage Gross Acres	Undeveloped acreage Net Acres	Developed acreage Gross Acres	Developed acreage Net Acres	Producing Wells Gross	Producing Wells Net	Non-Producing Wells Gross	Non-Producing Wells Net
Indonesia	239,692	28,763						
Canada	4,480	1,493						
Texas	1,766	1,766	2,027	2,027	3	3	1	1
California	1,280	1,280						
Total	247,218	33,302	2,027	2,027	3	3	1	1

The following table sets forth as of December 31, 2010, 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, 2011	531	531	239,692	28,763		
December 31, 2012	1,109	1,109			4,480	1,493
December 31, 2013	1,280	1,280				
December 31, 2014	126	126				
December 31, 2015 and thereafter						
	3,046	3,046	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, 2010	2009
Production:		
Natural gas (MMcf) (1)	733	1,278
Natural gas (MMcf/d) (1)	2.01	3.50
Average Sales Prices (2)		
Natural gas ($per Mcf) (2)	$ 4.17	$ 3.19
Lease Operating Expense ($per Mcf) (3)	$ 0.51	$ 0.66

(1) Production volumes for 2010 and 2009 represent actual plant throughput.

(2) The sales price reflected for the years ended December 31, 2010 and 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.

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***

(d) 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. On September 11, 2009, our subsidiary, Redwood Energy Production, L.P. filed an Original Petition for Declaratory Judgment against Devon Energy Production Company L.P. (Devon) regarding certain over-riding royalty interests and related revenue amounts claimed by Devon. In September 2010 we entered into a settlement agreement with Devon, In connection with this settlement we issued a 5-year non-interest bearing note payable in the amount of $375,000, made a cash payment of $300,000. We have recognized a gain in the amount of $182,751 in connection with this settlement.

ITEM 4. ***Reserved***

Not applicable.

Table of Contents

PART II

ITEM 5. ***Market for the Registrants Common Equity, Related Shareholder Matters and Purchases of Equity Securities***

Common Stock

Market Information. Our common stock trades on the NYSE Amex under the symbol GPR .

The range of high and low closing prices for our Common Stock for each quarterly period from January 1, 2009 through December 31, 2010 as reported by the NYSE Amex:

	NYSE Alternext US			
	High		Low	
2010				
Fourth Quarter	$	0.56	$	0.41
Third Quarter	$	0.52	$	0.40
Second Quarter	$	0.62	$	0.44
First Quarter	$	0.82	$	0.61
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

On March 30, 2011, the closing sale price for the Common Stock as reported by the NYSE Amex was $0.68 per share.

Holders. On March 28, 2011, the number of holders of record of our common stock was 375.

Dividends. We have not paid or declared any cash dividends on our common stock in the past and do not intend to pay or declare any cash dividends in the foreseeable future. We currently intend to retain future earnings for the future operation and development of our business including exploration, development and acquisition activities. Any future dividends would be subordinate to the full cumulative dividends on all shares of our Series B Preferred Stock.

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 therefore and, when declared, dividends were paid at the rate of $0.06 per share per annum, paid on a calendar quarter basis. During 2010, we declared $451,380 in dividends associated with the Series B preferred stock, of which $448,070 had been paid as of December 31, 2010.

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 in February 2007 and has not terminated. On our registration statement on Form S-1 (Reg. No. 333-146557) we

Table of Contents

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 $6,171,518, 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 $6,171,518 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 $179,000 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

In September and October 2010, we completed a sale through a private placement transaction to certain institutional and individual accredited investors. Units were priced at $0.48 per unit, and each unit consisted of one share of no par value common stock and a one-half common share purchase warrant. Each one whole warrant entitles the holder to acquire one common share at a price of $0.75 per share for a period of three years. The total aggregate purchase price for the units sold was $1,773,600, and represented the sale of 3,695,000 common shares and 1,847,500 warrants. We granted piggyback registration rights to the investors with respect to the shares of common stock and common stock issuable upon exercise of the Warrants which the investors acquired in the transaction. The Company paid no fees or commissions in connection with the sale of the units.

On December 30, 2010, we completed a sale through a private placement transaction to certain institutional and individual accredited investors. Units were priced at $0.45 per unit and each unit consisted of one share of no par value common stock, and one-half common share purchase warrant. Each one whole warrant entitles the holder to acquire one common share at a price of $0.75 per share for a period of three years. The total aggregate purchase price was $500,038 and represented the sale of 1,111,199 common shares and 555,596 warrants to acquire common shares. In connection with the sale, we granted piggyback registration rights to the investors with respect to the shares of common stock and common stock issuable upon exercise of the warrants which the investors acquired. The Company paid no fees or commissions in connection with the sale of the units.

GeoPetro issued the aforementioned common shares and warrants in reliance on the exemption from registration provided for under Section 4(2) of the Securities Act of 1933, as amended (the Securities Act), and Rule 506 of Regulation D thereunder. GeoPetro 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 purchasers, including the representations with respect to each purchaser s status as an accredited investor, as such term is defined in Rule 501(a) of the Securities Act, and each purchaser s investment intent with respect to the securities purchased.

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, 2010 and 2009 and the balance sheet data as of December 31, 2010 and 2009 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, 2008, 2007 and 2006 and the balance sheet data as of December 31, 2008, 2007, and 2006 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.

Table of Contents

	For The Years Ended December 31, 2010	2009	2008	2007	2006
Consolidated Statement of Operations:					
Revenues	$ 3,054,255	$ 4,077,355	$ 6,152,542	$ 6,890,777	$ 6,716,360
Plant operating expense	3,944,120	4,832,548			
Lease operating expense	371,719	606,266	1,484,267	1,558,900	1,602,932
General and administrative	2,417,119	2,767,385	2,717,121	2,807,091	2,347,447
Net profits expense			579,941	679,337	632,708
Impairment expense		20,843,305	69,856	1,111,151	38,849
Depreciation and depletion expense	695,893	1,595,597	1,553,418	2,269,995	2,406,612
Earnings (loss) from operations	(4,424,596)	(26,567,746)	(252,061)	(1,535,697)	(312,188)
Net income (loss)	(4,937,559)	(25,808,260)	(174,825)	(1,616,804)	(482,406)
Net income (loss) attributable to common shareholders	$ (5,388,939)	$ (25,987,305)	$ (174,825)	$ (1,616,804)	$ (1,011,806)
Earnings (Loss) per Share:					
Basic	$ (0.15)	$ (0.76)	$ (0.01)	$ (0.05)	$ (0.04)
Diluted	$ (0.15)	$ (0.76)	$ (0.01)	$ (0.05)	$ (0.04)
Weighted Average Number of Common Shares Outstanding:					
Basic	35,306,255	34,284,646	32,511,251	29,830,447	25,990,868
Diluted	35,306,255	34,284,646	32,511,251	29,830,447	25,990,868
Production Data:					
Natural gas (Mcf)	733,286	1,278,434	1,275,445	2,005,359	2,229,059
Natural gas (Mcf/d)	2,009	3,503	3,494	5,494	6,107
Production Data Reduced by Net Profits interests:					
Natural gas (Mcf)	733,286	1,118,630	1,116,014	1,754,689	1,950,427
Natural gas (Mcf/d)	2,009	3,065	3,058	4,807	5,344
Average Sales Prices:					
Natural gas (per Mcf)	$ 4.17	$ 3.19	$ 4.82	$ 3.44	$ 3.01

	For the Years Ended December 31, 2010	2009	2008	2007	2006
Balance Sheet Information:					
Current assets	$ 1,169,213	$ 3,044,731	$ 1,023,090	$ 5,723,680	$ 2,366,081
Total assets	30,873,537	34,004,213	54,076,005	44,116,606	39,061,478
Current liabilities	4,159,223	4,218,956	3,174,742	2,361,827	3,604,342
Current portion of Long-term liabilities	1,981,263	1,549,829	600,000		
Long-term liabilities	5,634,032	6,051,654	7,078,548	53,726	48,842
Redeemable Series AA Preferred Stock					5,924,068
Series B Preferred Stock	5,448,602	5,448,602			
Accumulated Deficit	(43,561,858)	$ (38,172,919)	$ (12,185,614)	$ (12,010,789)	$ (10,393,985)

Table of Contents

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

The following discussion and analysis should be read in conjunction with the Selected Financial Data and the accompanying consolidated financial statements and related notes included elsewhere in this Annual Report on Form 10-K. The following discussion 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. See Cautionary Information About Forward-Looking Statements .

BUSINESS 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 249,245 gross (35,329 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.

Our objective is to increase shareholder value by profitably growing our reserves, production, revenue, and cash flow by focusing primarily on our projects in Texas, Alaska, California, Canada, Indonesia, and certain new venture opportunities.

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 2011. We expect the majority of our capital expenditures in 2011 will be for the Madisonville Project.

	For The Years Ended December 31, 2010	2009
Consolidated Statement of Operations:		
Revenues	$ 3,054,255	$ 4,077,355
Plant operating expense	3,994,120	4,832,548
Lease operating expense	371,719	606,266
General and administrative	2,417,119	2,767,385
Net profits expense		
Impairment expense		20,843,305
Depreciation and depletion expense	695,893	1,595,597
Loss from operations	(4,424,596)	(26,567,746)
Net loss	(4,937,559)	(25,808,260)
Net loss attributable to common shareholders	$ (5,388,939)	$ (25,987,305)

Revenue and Operating Trends in 2010

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 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 2011. 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, 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 2011 as compared to 2010 and prior periods. To accomplish the plant upgrades, we will need to raise capital in 2011. Due to the unsettled state of the capital markets, funds may not be available, or may not be available on favorable terms.

Table of Contents

Industry Overview for the year ended December 31, 2010

Natural gas prices have historically been volatile. Price volatility during 2010 and 2009 relates to supply concerns earlier in 2009, and more recently due to recession concerns arising from the current global financial crisis and a resultant decline in demand for natural gas. 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, 2010 was $4.14 per Mcf versus $5.72 per Mcf as of December 31, 2009. Fluctuations in the price for natural gas are closely associated with customer demand relative to the volumes produced and the level of inventory in underground storage.

Company Overview in 2010

Our net loss after taxes for the year ended December 31, 2010 was $5,388,939. 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, 2010 of $43,561,858. Commencing in May 2003, we placed our Madisonville Project into production. Substantially all of our revenues for the year ended December 31, 2010 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, 2010 and 2009

During the twelve months ended December 31, 2010, we had gross natural gas revenues $3,054,255. During this period, our gross production from our wells was 733,286 Mcf and our average natural gas price realized was $4.17 per Mcf. During the twelve months ended December 31, 2009, we had natural gas revenues of $4,077,355, and our gross production was 1,278,434 Mcf of natural gas at an average price of $3.19 per Mcf. Revenues decreased in the twelve months ended December 30, 2010 as compared to the prior year period mainly due to lower production volumes. The 42.6% lower production volumes for the twelve months ended December 31, 2010 as compared to the same period of 2009 was due to natural decline curves as well as treatment plant downtime partially offset by a 30.7% increase in average natural gas prices.

During the twelve months ended December 31, 2010, we incurred plant operating expenses of $3,994,120, as compared to $4,832,548 in the same prior year period. The decrease of $838,428 or 17.3% was attributable to cost cutting measures comprised primarily of reduced costs associated with field personnel, chemicals, electricity and ad valorem taxes.

During the twelve months ended December 31, 2010, we incurred lease operating expense of $371,719. Our average lifting cost for the 2010 period was $0.51 per Mcf. 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 $0.47 per Mcf. Despite overall lease operating expenses being lower in 2010, the average lifting cost per Mcf was higher during the period, due to fixed costs associated with field personnel, insurance costs, workover costs, and ad valorem property taxes applicable to the wells, on a lower base of production volume.

General and administrative (**G&A**) expenses for the twelve months ended December 31, 2010 were $2,417,119 compared to $2,767,385 for the twelve months ended December 31, 2009. This represents a $350,266 or 12.7% decrease over the prior year period. The net reduction in G&A expense incurred in 2010 was due primarily to reduced salaries, professional fees, and insurance, partially offset by an increase in rent expense.

For the year ended December 31, 2010, impairment expense was $nil versus $20,843,305 for the same period of 2009. 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 from ceiling test write limitations.

Depreciation and depletion expense for the twelve months ended December 31, 2010 was $695,893 as compared to $1,595,597 in the same period of 2009, which amounts primarily represent depletion of the oil and gas properties for the twelve months ended December 31, 2010 and 2009, respectively. The 56.4% decrease was due to decreased depletion expense resulting from lower net production in the twelve months period of 2010 as well as lower carrying value of oil and gas properties resulting from ceiling test write-off in the US cost pool recorded during the fiscal year ended December 31, 2009.

During the twelve months ended December 31, 2010, a gain was realized in connection with the settlement of previously accrued liabilities related to the Devon royalty rights in the amount of $182,751. During the twelve months ended December 31, 2009, a gain on the sale of equipment of $1,488,687 was realized relating to the sale of idle equipment in the Madisonville Plant.

Table of Contents

During the twelve months ended December 31, 2010 and 2009, interest expense was incurred in the amount of $696,857 and $736,596, respectively. The decrease in interest expense is due to a decrease in indebtedness on notes payable during the period, and by the replacement of certain loans with new instruments bearing lower interest rates.

Net loss before taxes for the twelve months ended December 31, 2010 was $4,936,759 as compared to $25,809,251 for the twelve months ended December 31, 2009. The decrease in net loss during the twelve months ended December 31, 2010 was primarily due to the fact that we recorded no impairment expense, experienced reduced depletion expense and lower general and administrative expense. In addition operating costs decreased at a rate higher than decreased production revenues, thereby providing a positive change in operating margin year over year.

Recent Developments

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 as of December 31, 2010 are as follows:

2011		145,635
2012		149,836
2013		154,037
2014		158,238
2015		162,439
2016		166,640
2017		56,013
Total	$	992,838

On February 26, 2010, we sold our entire working interest in our Alaskan Leases to Linc, an Australian-based company publicly traded on the Australian Stock Exchange. Linc acquired all of the Alaskan Leases for the following consideration:

- a cash payment of $1.0 million;

- 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;

- after we have received the $4.0 million payment specified in paragraph (b) above, we will thereafter receive an over-riding 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 on conventional oil and gas production and coal bed methane production; and

- Linc has agreed to pay all of the costs of maintaining the Alaskan leases at least through the end of the primary lease term.

On November 18, 2010, Linc completed the drilling of the LEA#1 exploration well in the Point Mackenzie Block of the Cook Inlet Basin in Alaska. A testing program to evaluate the potential for commercial gas production from the well will be undertaken. In addition to testing the LEA #1, Linc Energy has stated that it will prepare for phase two of its Alaskan natural gas drilling program in the Trading Bay Block leases which are located on the northwest side of the Cook Inlet approximately 70 miles from the site of LEA #1.

On March 31, 2010, J. Chris Steinhauser resigned from his positions as the Chief Financial Officer, Vice President of Finance and Secretary of the Company to pursue other interests. The resignation notification submitted by Mr. Steinhauser did not reference any disagreement with the Company on any matter relating to the Company s operations, policies and practices.

On April 26, 2010 we extended our Vice President of Exploration, David V. Creel s employment agreement through December 31, 2010, all other provisions per the terms of the original employment agreement remained unchanged. As of March 31, 2011 Mr. Creel continues to serve in his capacity as Vice President of Exploration on a month to month basis.

On July 19, 2010, we modified the original exercise price for 740,000 stock options from $4.28 as issued on June 27, 2008 to $0.50 per share. The additional compensation cost to be recognized in connection with the re-pricing of these options is $113,882 and will be recognized over the requisite service periods of the underlying options.

Table of Contents

On July 19, 2010, we granted a total of 195,000 stock options to five non-management directors at an exercise price of $0.50 per share. These options will vest ratably over five (5) years pursuant to the terms of the 2004 Stock Option and Appreciation Rights Plan. The grant date fair value of the options was $59,984.

On September 1, 2010 and October 31, 2010, we issued a total of 95,000 warrants to purchase our common shares at $0.50 in conjunction with the renewal of certain promissory notes payable. The warrants expire on August 31, 2013 and October 30, 2013, respectively.

On September 30, 2010, we entered into a legal settlement with Devon. In connection with the settlement we issued a non-interest bearing note in the amount of $375,000 payable over 5 years, and paid $300,000 on October 1, 2010. We have recorded a gain in the amount of $182,751 in connection with this settlement.

On September 30, 2010 and early October 2010, we completed a sale through a private placement transaction to certain institutional and individual accredited investors. The total placement consisted of 3,695,000 units priced at $0.48 per unit. Each unit consisted of one share of no par value common stock, and a one-half common share purchase warrant. Each one whole warrant entitles the holder to acquire one common share at a price of $0.75 per share for a period of three years. The total aggregate purchase price for the units sold was $1,773,600, and represented the sale of 3,695,000 common shares and 1,847,500 warrants.

On December 23, 2010, we issued 1 year $300,000 promissory notes payable through our subsidiary, GeoPetro Canada, at a 6% annual interest rate. We issued to the note holders warrants to purchase 75,000 shares of our common stock at a price of $0.50 per share over three year term.

On December 30 2010, we completed a sale through a private placement transaction to certain institutional and individual accredited investors. The total placement consisted of 1,111,199 units priced at $0.45 per unit. Each unit consisted of one share of no par value common stock, and a one-half common share purchase warrant. Each one whole warrant entitles the holder to acquire one common share at a price of $0.75 per share for a period of three years. The total aggregate purchase price for the units sold was $500,038, and represented the sale of 1,111,199 common shares and 555,596 warrants.

On January 6, 2011, we entered into a sublease agreement whereby a portion of the Company s principal executive offices have been leased to a third party. The terms of the sublease agreement include a seventy-five month term cancelable by either party with ninety days written notice after December 31, 2011. The Company will recoup approximately 50% of the base rental obligation through the sublease agreement.

In February 2011, we extended the maturity on three separate notes totaling $850,000 to December 2012. In connection with the extension, the Company extended the warrants to purchase our common stock associated with these three notes for an additional year.

In February 2011, we extended the maturity of two notes totaling $365,000 through May 2013. In connection with the extension, the Company extended the warrants to purchase our common stock associated with these two notes for an additional year.

In February 2011, we extended the maturity of two notes totaling $300,000 through June 2012. In connection with the extension, the Company extended the warrants to purchase our common stock associated with these two notes for an additional year.

In February 2011, Stuart J. Doshi, President and CEO, advanced to us a loan in the amount of $125,000. The note will accrue interest at 8% annually and is payable on demand.

During February and March 2011, we completed a private placement transaction. The total placement consisted of 2,050,328 units priced at $0.45 per unit. Each unit consisted of one share of no par value common stock, and a one-half common share purchase warrant. Each one whole warrant entitles the holder to acquire one common share at a price of $0.75 per share for a period of three years. The total aggregate purchase price for the units sold was $922,648, and represented the sale of 2,050,328 common shares and 1,025,164 warrants.

In March 2011, the Company modified its bank loan with Bank of Oklahoma, the Fourth Amendment of the Amended and Restated Term Loan Agreement which extends the loan by an additional year so as to have a new maturity date being December 31, 2012. The terms of the 4th amendment provide for minimum quarterly principal payments of $150,000, minus $150,000 times a fraction, the numerator of which is the sum of all principal payments made by us after March 15, 2011 but prior to such payment date, and the denominator of which is $4,552,847. The loan fee of $180,000 will be added to the principal balance. The interest is payable quarterly in arrears at prime plus 3.25% or Libor plus 4.75% at the option of the Company. The agreement contains customary affirmative and negative covenants including restrictions on incurring debt in the amount in excess of $375,000.

Table of Contents

Liquidity and Capital Resources

We had a working capital deficit of $2,990,010 at December 31, 2010 versus $1,174,225 at December 31, 2009. Our working capital deficit increased during the year ended December 31, 2010 primarily to losses incurred in connection with natural gas operations, the payment of dividends on our preferred shares, and the repayments of debt obligations.

Our cash balance at December 31, 2010 $947,863 compared to a cash balance of $2,429,891 at December 31, 2009. The change in our cash balance is summarized as follows:

Cash balance at December 31, 2009	$	2,429,891
Sources of cash:		
Cash provided by investing activities		1,000,000
Cash provided by financing activities		1,089,568
Total sources of cash including cash on hand		4,519,459
Uses of cash:		
Cash used by operating activities		(3,423,674)
Cash used in investing activities:		
Oil and natural gas property expenditures		(99,014)
Capital asset expenditures		(48,908)
Total uses of cash		(3,571,596)
Cash balance at December 31, 2010	$	947,863

Net cash used in operating activities of $3,423,674 and $4,773,997 for the years ended December 31, 2010 and 2009 respectively are attributable to our net income adjusted for non-cash charges as presented in the consolidated statements of cash flows and changes in working capital as discussed above.

We have historically financed our business activities through December 31, 2010 principally through issuances of preferred stock, 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, 2010		December 31, 2009	
Proceeds from sale of common shares and warrant exercises, net	$	2,273,638	$	
Proceeds from sale of Preferred Series B, net				5,448,602
Payment on preferred dividends		(448,070)		(68,583)
Repayments of promissory notes		(700,000)		(1,825,000)
Proceeds from promissory notes		300,000		1,897,000
Payments of liabilities settlement		(300,000)		
Payment of loan fee		(36,000)		(40,000)

Repayment of related party note				(132,000)
Net cash provided by financing activities	$	1,089,568	$	5,280,019

38

Table of Contents

On September 30, 2010 and early October 2010, we completed a sale through a private placement transaction to certain institutional and individual accredited investors. The total placement consisted of 3,695,000 units priced at $0.48 per unit. Each unit consisted of one share of no par value common stock, and a one-half common share purchase warrant. Each one whole warrant entitles the holder to acquire one common share at a price of $0.75 per share for a period of three years. The total aggregate purchase price for the units sold was $1,773,600, and represented the sale of 3,695,000 common shares and 1,847,500 warrants. On December 30 2010, we completed a sale through a private placement transaction to certain individual accredited investors. The placement consisted of 1,111,199 units priced at $0.45 per unit. Each unit consisted of one share of no par value common stock, and a one-half common share purchase warrant. Each one whole warrant entitles the holder to acquire one common share at a price of $0.75 per share for a period of three years. The total aggregate purchase price for the units sold was $500,038, and represented the sale of 1,111,199 common shares and 555,596 warrants.

In December 2010, we issued 1-year notes payable at 6% per annum compounded annually in the amount of $300,000 with maturity dates of December 31, 2011. In connection with the notes, the Company granted three-year exercisable warrants to purchase 75,000 shares of Common Shares at $0.50 per share. The fair value of the stock purchase warrants issued in connection with this note of $16,662.

In 2010 we paid $448,070 in dividends on our Preferred Series B shares in addition to $1,036,000 in repayments of promissory notes, the settlement of liabilities and loan fees.

In 2009 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. 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.

In 2009 we paid $68,583 in dividends on our Preferred Series B shares in addition to $1,997,000 in repayments of notes payable and loan fees.

The net proceeds of our equity and note financings coupled with net cash provided by investing activities of $852,078 and $1,153,090 in 2010 and 2009 resulting primarily from the disposition of our Alaskan Leases for total proceeds of $1,000,000 in 2010 and the sale of idle equipment for total proceeds of $2,500,000 in 2009, were primarily used to fund operating activities and invested in oil and natural gas properties and our gas processing plant totaling $99,014, and $1,346,910 for the years ended December 31, 2010 and 2009, respectively.

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 2011 for a description of our expected capital expenditures for 2011. 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 2011 , we are forecasting capital expenditures of $3.2 million during 2011. We will need to obtain adequate sources of cash to fund our anticipated capital expenditures through the end of 2011, to fund ongoing operations 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 farm-out certain of our projects. Additionally, as a result of the 2009 & 2010 economic downturn, we 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 2011 and future periods. In addition, exploratory and development drilling is scheduled during 2011 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:

- 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;
- reduce general and administrative expenses; and/or
- forfeit our interest in wells that are proposed to be drilled.
- selling certain underutilized equipment from our gas plant

Table of Contents

Outlook for 2011 Capital

Depending on capital availability, we are forecasting capital spending of up to approximately $3,207,000 during the year 2011, 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 $179,000 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 the majority 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 2011 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, 2010, GeoPetro had net operating loss (NOL) carryforwards of approximately $37,234,000 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 $11,872,000 of California net operating losses and approximately $670,000 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, 2010, we had net deferred tax assets of approximately $14,927,000 related to the NOL and other temporary differences. We have recorded a full valuation allowance of $14,927,000 at December 31, 2010 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, 2010, 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 2011.

Table of Contents

Impact of Inflation & Changing Prices

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

	For the Year Ended December 31, 2010		2009 (1)	
Average Sales Prices per Mcf	$	4.17	$	3.19
Net Production Volume Mcf		733,286		1,278,434
Revenues	$	3,054,255	$	4,077,355
Loss from Operations	$	(4,424,596)	$	(26,567,746)

(1)Loss from operations includes $20,843,305 impairment expense

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 2010 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.

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.

Table of Contents

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 $424,502 and $403,963 of stock-based employee compensation for the twelve months ended December 31, 2010 and 2009, respectively.

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.

Hedging. We did not enter into any hedging transactions during the years ended December 31, 2009 or 2010.

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

The reports of our independent registered public accounting firm 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 interim 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, 2010. Based on this evaluation, we have concluded that, as of December 31, 2010, 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, 2010. 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 the 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

Table of Contents

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.

Table of Contents

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 2010 Annual Meeting of Shareholders, to be filed on or before April 30, 2011, the 2011 proxy statement.

Item 11. ***Executive Compensation***

The information required by this item is incorporated by reference from our 2011 proxy statement.

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

The information required by this item is incorporated by reference from our 2011 proxy statement.

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

The information required by this item is incorporated by reference from our 2011 proxy statement.

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

The information required by this item is incorporated by reference from 2011 proxy statement.

Table of Contents

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.

Table of Contents

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, 2011.

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, 2011.

Signature	Title	Date
/s/ Stuart J. Doshi Stuart J. Doshi	Chairman of the Board, President and Chief Executive Officer	March 31, 2011
/s/ David V. Creel David V. Creel	Vice President of Exploration and Director	March 31, 2011
/s/ Paul D. Maniscalco Paul D. Maniscalco	Interim Chief Financial Officer and Principal Accounting Officer	March 31, 2011
/s/ Jason B. Selch Jason B. Selch	Director	March 31, 2011
/s/ Christopher T. Czuppon Christopher T. Czuppon	Director	March 31, 2011
/s/ Thomas D. Cunningham Thomas D. Cunningham	Director	March 31, 2011
/s/ David G. Anderson David G. Anderson	Director	March 31, 2011
/s/ Nick DeMare Nick DeMare	Director	March 31, 2011

Table of Contents

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.

Farm-out 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.

Table of Contents

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.

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.

Table of Contents

(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 .

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.

Table of Contents

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

Table of Contents

GEOPETRO RESOURCES COMPANY

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Table of Contents

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, 2010. 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, 2010, 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/ Paul D. Maniscalco
Stuart J. Doshi	Paul D. Maniscalco
President, Chief Executive Officer and Chairman	Interim Chief Financial Officer

Table of Contents

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, 2010 and 2009, 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. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of GeoPetro Resources Company and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the years then ended in conformity with U.S. generally accepted accounting principles.

*/s/ **HEIN** & ASSOCIATES LLP*
Dallas, Texas
March 31, 2011

Table of Contents

GEOPETRO RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS

	December 31, 2010		December 31, 2009	
ASSETS				
Current Assets				
Cash and cash equivalents	$	947,863	$	2,429,891
Trade accounts receivable oil and gas sales		125,593		473,944
Accounts receivable other		215		8,658
Prepaid expenses		95,542		132,238
Total current assets		1,169,213		3,044,731
Oil and gas properties, at cost (full cost method)				
Unproved properties		7,613,007		8,411,773
Proved properties		51,342,268		51,194,852
Gas processing plant		10,285,573		10,285,573
Less accumulated depletion, depreciation and impairment		(39,637,551)		(38,950,914)
Net oil and gas properties		29,603,297		30,941,284
Furniture, fixtures and equipment, at cost, net of depreciation		56,427		2,071
Other assets		44,600		16,127
Total Assets	$	30,873,537	$	34,004,213
LIABILITIES AND SHAREHOLDERS EQUITY				
Current Liabilities				
Trade payables	$	1,235,764	$	950,097
Current portion of long term notes payable		1,981,263		1,549,829
Interest payable		187,006		136,233
Dividends payable		113,772		110,462
Production taxes payable		244,929		309,904
Other taxes payable		15,037		11,147
Royalty owners payable		381,452		1,151,284
Total current liabilities		4,159,223		4,218,956
Long Term Notes Payable		5,487,587		5,986,645
Asset Retirement Obligations		71,510		65,009
Other Long Term Liabilities		74,935		
Total Liabilities		9,793,255		10,270,610
Commitments and Contingencies (Notes 2, 5, 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, 2010 and 2009. Liquidation preference of $5,642,250		5,448,602		5,448,602
Common stock, no par value; 100,000,000 shares authorized; 39,090,845 and 34,284,646 shares issued and outstanding at December 31, 2010 and December 31, 2009, respectively		55,671,371		53,397,733
Additional paid-in-capital		3,522,167		3,060,187

Accumulated deficit		(43,561,858)		(38,172,919)
Total shareholders equity		21,080,282		23,733,603
Total Liabilities and Shareholders Equity	$	30,873,537	$	34,004,213

See accompanying notes to these consolidated financial statements.

Table of Contents

GEOPETRO RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31, 2010	2009
Revenues		
Natural gas sales	$ 3,054,255	$ 4,077,355
Costs and Expenses		
Plant operating	3,994,120	4,832,548
Lease operating	371,719	606,266
General and administrative	2,417,119	2,767,385
Impairment of oil and gas properties		20,843,305
Depreciation and depletion	695,893	1,595,597
Total costs and expenses	7,478,851	30,645,101
Loss from operations	(4,424,596)	(26,567,746)
Other Income (Expense)		
Interest expense	(696,857)	(736,596)
Interest income	1,943	6,404
Gain on sale of equipment		1,488,687
Gain recognized in connection with settlement of liability	182,751	
Total other income (expense)	(512,163)	758,495
Loss Before Taxes	(4,936,759)	(25,809,251)
Income tax (expense) benefit	(800)	991
Net Loss	(4,937,559)	(25,808,260)
Preferred stock dividend	(451,380)	(179,045)
Net Loss Available to Common Shareholders	$ (5,388,939)	$ (25,987,305)
Net Loss Per Common Shares Basic and Diluted	$ (0.15)	$ (0.76)
Weighted average number of common shares outstanding basic and diluted	35,306,255	34,284,646

See accompanying notes to these consolidated financial statements.

Table of Contents

GEOPETRO RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY

FOR THE YEARS ENDED DECEMBER 31, 2010 AND 2009

	Preferred Stock Series B		**Common Stock**		**Additional Paid-in Capital**	**Accumulated Deficit**	**Total Shareholders Equity**
	Shares	**Amount**	**Shares**	**Amount**			
Balances, January 1, 2009		**$**	**34,284,646**	**$ 53,397,733**	**$ 2,610,596**	**$ (12,185,614)**	**$ 43,822,715**
Issuance of Series B preferred stock for cash net	7,523,000	5,448,602					5,448,602
Share-based compensation					403,963		403,963
Fair value of warrants issued in connection with notes payable					45,628		45,628
Net loss						(25,808,260)	(25,808,260)
Dividends on Series B preferred stock						(179,045)	(179,045)
Balances, December 31, 2009	**7,523,000**	**5,448,602**	**34,284,646**	**53,397,733**	**3,060,187**	**(38,172,919)**	**23,733,603**
Issuance of common stock for cash			4,806,199	2,273,638			2,273,638
Share-based compensation					424,502		424,502
Fair value of warrants issued in connection with notes payable					37,478		37,478
Net Loss						(4,937,559)	(4,937,559)
Dividends on Series B preferred stock						(451,380)	(451,380)
Balances, December 31, 2010	**7,523,000**	**$ 5,448,602**	**39,090,845**	**$ 55,671,371**	**$ 3,522,167**	**$ (43,561,858)**	**$ 21,080,282**

See accompanying notes to these consolidated financial statements.

Table of Contents

GEOPETRO RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31, 2010	2009
Cash Flows From Operating Activities		
Net loss	$ (4,937,559)	$ (25,808,260)
Adjustments to reconcile net loss to net cash used in operating activities:		
Depreciation and depletion	695,893	1,595,598
Share-based compensation expense	424,502	403,963
Non-cash interest expense	120,970	62,649
Impairment of oil and gas properties		20,843,305
Gain on sale of equipment		(1,488,687)
Gain recognized in connection with settlement of liability	(182,751)	
Accretion of discount on asset retirement obligations	5,201	4,728
Changes in operating assets and liabilities:		
Accounts receivable	348,351	(443,229)
Other assets	16,665	72,013
Current liabilities	24,822	(16,077)
Other	60,232	
Net cash used in operating activities	(3,423,674)	(4,773,997)
Cash Flows from Investing Activities		
Additions to oil and gas properties	(99,014)	(758,006)
Additions to gas processing plant		(588,904)
Acquisition of furniture, fixtures, equipment and tenant lease improvement	(48,908)	
Proceeds from sale of equipment		2,500,000
Dispositions of oil and gas properties	1,000,000	
Net cash provided by investing activities	852,078	1,153,090
Cash Flows from Financing Activities		
Proceeds from issuance of common shares, option and warrant exercises, net	2,273,638	
Proceeds from issuance of Series B preferred stock, net		5,448,602
Payments of preferred dividends	(448,070)	(68,583)
Proceeds from promissory notes	300,000	1,897,000
Payments of loan fee	(36,000)	(40,000)
Payment of settlement of liability	(300,000)	
Repayments of promissory notes	(700,000)	(1,825,000)
Repayments of related party notes		(132,000)
Net cash provided by financing activities	1,089,568	5,280,019
Net Increase (Decrease) in Cash and Cash Equivalents:	(1,482,028)	1,659,112
Cash and Cash Equivalents		
Beginning of period	2,429,891	770,779
End of period	$ 947,863	$ 2,429,891

Supplemental Disclosure of Cash Flow Information				
Cash paid for interest	$	525,115	$	462,786
Cash (refund) paid for income taxes	$	800	$	(991)
Non-Cash Transactions				
Issuance of warrants in connection with promissory notes and private placements	$	544,245	$	45,628

See accompanying notes to these consolidated financial statements.

Table of Contents

GEOPETRO RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Information subsequent to December 31, 2010 is unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

GeoPetro GeoPetro Resources Company (we, us, our, GeoPetro or the Company) was originally incorporated as GeoPetro Company under laws of the State of Wyoming in 1994 to participate in the oil and gas acquisition, exploration, development and production business in the United States and internationally. GeoPetro Company was subsequently merged into GeoPetro Resources Subsidiary Company, a California corporation, on June 28, 1996. GeoPetro s name was then changed to GeoPetro Resources Company. GeoPetro s corporate offices are in San Francisco, California. The accompanying consolidated financial statements include the accounts of GeoPetro and its wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

2. LIQUIDITY

As of December 31, 2010, GeoPetro recorded had a working capital deficit of $2,990,010 and an accumulated deficit of $43,561,858. Further, GeoPetro generated net losses of $5,388,939 and $25,987,305 during the years ended December 31, 2010 and 2009 respectively. GeoPetro s ability to meet its contractual obligations and remit payment under its arrangements with its vendors depends on its ability to generate additional financing. GeoPetro s management continues to renegotiate the terms of its existing borrowing arrangements and raise additional capital through debt and equity issuances.

Since its inception, GeoPetro has participated as a working interest owner in the acquisition of undeveloped leases, seismic options, lease options and foreign concessions and has participated in seismic surveys and the drilling of test wells on its undeveloped properties. More recently, we acquired a natural gas treatment plant in East Texas. Exploratory and development drilling is scheduled during 2011 and future periods on GeoPetro s undeveloped properties and capital improvements are planned on the natural gas treatment plant. The planned capital improvements at the natural gas treatment plant and the exploration activities together with others that may be entered into exceed the existing working capital of GeoPetro. Management will need to raise additional equity and/or debt capital, to finance its continued activities. Management believes that GeoPetro will be successful in obtaining adequate sources of cash to fund its anticipated capital expenditures and operating expense through the end of 2011, but there can be no assurance that management will be successful in raising sufficient additional equity and/or debt capital. If additional financing is not available, GeoPetro will be compelled to reduce the scope of its business activities including, but not limited to the following:

- Selling certain underutilized equipment from our gas plant;

- Selling working interests in its Madisonville operations to other parties;
- farming-out its interest in proposed wells;
- forfeiting its interest in wells that are proposed to be drilled and/or;
- reducing general and administrative expenses;

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

U.S. GAAP The Company s financial statements have been prepared in accordance with accounting principles generally accepted within the United States of America (U.S. GAAP).

Use of Estimates and Significant Estimates Certain amounts in GeoPetro s financial statements are based upon significant estimates, including oil and gas reserve quantities which form the basis for the calculation of depreciation, depletion, amortization and impairment of oil and gas properties, the carrying values of unproved properties, asset retirement obligations, accounting for business combinations and share-based payments, and a provision for income taxes. Actual results could materially differ from those estimates.

Oil and Gas Properties GeoPetro follows the full cost method of accounting for oil and gas producing activities and, accordingly, capitalizes all costs incurred in the acquisition, exploration, and development of proved oil and gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual 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

Table of Contents

capitalized costs, with no gain or loss recorded. Costs incurred for repairs and maintenance are expensed as incurred. 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.

Asset Impairment 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 average oil and gas prices to estimated future production of proved oil and gas reserves as of period-end, less estimated future expenditures to be incurred in developing and producing the proved reserves assuming the continuation of existing economic conditions. In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserves reporting requirements. We adopted the rules effective December 31, 2009. 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, this resulted in a ceiling test write-down of $19,798,390 associated with the US full cost pool for the year ended December 31, 2009. There was no impairment of proved oil and gas properties indicated at December 31, 2010.

For the unproved properties, the Company evaluates the possibility of potential impairment on a quarterly basis. During the twelve months ended December 31, 2009 approximately $1,020,270 of unproved property costs related to Canadian exploration projects and $24,644 of unproved property costs related to Indonesia exploration were reclassified to proved property and ceiling test impairment was recorded in the Canadian and Indonesia full cost pool due to dry holes drilled. There was no impairment of unproved oil and gas properties indicated at December 31, 2010.

Joint Ventures Some exploration and production activities are conducted jointly with others and, accordingly, the accounts reflect only GeoPetro s proportionate interest in such activities.

Revenue Recognition Revenue is recognized upon delivery of gas production.

Asset Retirement Obligation In accordance with *Accounting for Asset Retirement Obligation,* ASC 410-20, the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. GeoPetro recorded an asset retirement obligation to reflect GeoPetro s legal obligations related to future plugging and abandonment of its oil and gas wells. GeoPetro estimated the expected cash flow associated with the obligation and discounted the amount using a credit-adjusted, risk-free interest rate. At least annually, GeoPetro reassesses the obligation to determine whether a change in the estimated obligation is necessary. GeoPetro evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should those indicators suggest the estimated obligation has materially changed, GeoPetro will accordingly update its assessment.

There are asset retirement obligations associated with the Plant. However, components of the Plant can be used for extended and indeterminate periods of time as long as they are properly maintained and/or upgraded. GeoPetro s intent is to maintain the Plant assets and continue making improvements to those assets based on technological advances. As a result, GeoPetro s management believes that the Plant has an indeterminate life for purposes of estimating asset retirement obligations because dates or ranges of dates upon which GeoPetro would retire the Plant cannot reasonably be estimated.

		December 31, 2010		2009
Asset retirement obligations, beginning of period	$	65,009	$	59,099
Liabilities incurred		1,300		1,182
Accretion expense		5,201		4,728
Asset retirement obligations, end of period	$	71,510	$	65,009

Furniture, Fixtures and Equipment Furniture, fixtures and equipment are stated at cost. Depreciation is provided on furniture, fixtures and equipment using the straight-line method over an estimated service life of three to seven years.

Income Taxes GeoPetro accounts for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts

Table of Contents

of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled. Because management has determined that realization of deferred tax assets is not more likely than not, the net deferred tax assets are fully reserved.

Concentrations of Credit Risk Credit risk represents the accounting loss that would be recognized at the reporting date if counterparties failed completely to perform as contracted. Concentrations of credit risk (whether on or off balance sheet) that arise from financial instruments exist for groups of customers or counterparties when they have similar economic characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions described below. The credit risk amounts for cash and accounts receivable do not take into account the value of any collateral or security.

GeoPetro maintains several cash accounts with higher quality financial institutions in amounts, which occasionally exceed current federal deposit insurance limits. Senior management continuously reviews these institutions for financial stability. The Company has not experienced any losses in connection with amounts in excess of federal deposit limits.

During the years ended December 31, 2010 and 2009, the Company had sales to customers exceeding 10% of total sales as follows:

	2010	**2009**
Luminant Energy Company, LLC	100%	100%

At December 31, 2010, and 2009, the Company had accounts receivable balances from Luminant Energy Company, LLC of $125,593 or 100% and $ 473,944 or 98% of total accounts receivable respectively.

Trade Accounts Receivable and Allowance for Doubtful Accounts Accounts receivable, oil and gas sales, consist of uncollateralized accrued revenues due under normal trade terms, generally requiring payment within 30 days. No interest is charged on past-due balances. Payments made on all accounts receivable are applied to the earliest unpaid items. Trade accounts receivable are recorded at net realizable value. If the financial condition of GeoPetro s customers were to deteriorate, resulting in an impairment of their ability to make payments, additional allowances may be required. Delinquent trade accounts receivable are charged against the allowance for doubtful accounts once uncollectibility has been determined. The allowance is determined through an analysis of the past-due status of accounts receivable and assessments of risk that are based on historical trends and an evaluation of the impact of current and projected economic conditions. There was no allowance for doubtful accounts needed as of the years ended December 31, 2010 or 2009.

Fair Value of Financial Instruments The estimated fair values for financial instruments are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. For certain of GeoPetro s financial instruments, including cash, accounts receivable, accounts payable and current portion of notes payable, the carrying amounts approximate fair value due to their maturities.

Share-Based Payments 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 after five years and expire five to ten years after the grant date. The Company measures and records 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. The compensation expense was recorded ratably over the requisite service period defined in the award. The Company recorded $424,502 and $403,963 of stock-based employee compensation for the twelve months ended December 31, 2010 and 2009, respectively. (Note 8)

Net Loss per Common Share Basic net loss per common share is computed by dividing the net loss attributable to common shareholders by the weighted average number of shares of common stock outstanding during the period.

Diluted net loss per common share is computed in the same manner, but also considers the effect of common stock shares underlying the following:

	Years Ended December 31,	
	2010	**2009**
Stock options (Note 8)	2,895,000	2,720,000
Warrants (Note 9)	4,032,065	1,561,547
Convertible preferred stock, Series B	7,523,000	7,523,000

Table of Contents

All of the common shares underlying the stock options and warrants above were excluded from diluted weighted average shares outstanding for each of the years in the period ended December 31, 2010 and 2009 because their effects were antidilutive.

Segment Reporting GeoPetro has oil and gas exploration, development and production operations in the United States, Canada, Australia and Indonesia. All revenues and related costs are associated with operations in the United States. A summary of assets and capital expenditures by geographical segment is included in Note 4.

Cash and Cash Equivalents Cash and cash equivalents include cash on hand, amounts held in banks and highly liquid investments purchased with an original maturity of three months or less.

Recently Issued Accounting Pronouncements The Company has evaluated recent accounting pronouncements and their adoption and we have not identified any that would have a material impact on the Company s financial position, or statements.

4. SUMMARY OF OIL AND GAS OPERATIONS

Capitalized costs at year end and costs incurred relating to GeoPetro s oil and gas properties are summarized as follows:

Capitalized costs as of December 31, 2010 are as follows:

	United States	Australia	Indonesia	Canada	Totals
Proved properties	$ 46,250,269	$ 2,388,051	$ 24,644	$ 2,679,304	$ 51,342,268
Unproved properties	4,420,467	1,522,718	1,337,172	332,650	7,613,007
Gas processing plant	10,285,573				10,285,573
Less accumulated depletion and impairment	(34,545,552)	(2,388,051)	(24,644)	(2,679,304)	(39,637,551)
Net capitalized costs	$ 26,410,757	$ 1,522,718	$ 1,337,172	$ 332,650	$ 29,603,297

Costs incurred for the year ended December 31, 2010 are as follows:

Gas processing plant acquisition	$	$	$	$	$
Exploration	194,936		3,375	2,922	201,233
Development	147,415				147,415
Total costs incurred	$ 342,351	$	$ 3,375	$ 2,922	$ 348,648

Capitalized costs as of December 31, 2009 are as follows:

	United States	Australia	Indonesia	Canada	Totals
Proved properties	$ 46,102,853	$ 2,388,051	$ 24,644	$ 2,679,304	$ 51,194,852
Unproved properties	5,225,530	1,522,718	1,333,797	329,728	8,411,773
Gas processing plant	10,285,573				10,285,573
Less accumulated depletion and impairment	(33,858,915)	(2,388,051)	(24,644)	(2,679,304)	(38,950,914)
Net capitalized costs	$ 27,755,041	$ 1,522,718	$ 1,333,797	$ 329,728	$ 30,941,284

Costs incurred for the year ended December 31, 2009 are as follows:

Gas processing plant acquisition	$ 445,341	$	$	$	$ 445,341
Exploration	528,532		45,000		573,532
Development	288,236				288,236
Total costs incurred	$ 1,262,109	$	$ 45,000	$	$ 1,307,109

During 2009, the Company recorded impairment write-downs associated with the Canadian proved cost pool due to dry holes of $1,020,270. The Company also record impairment write-downs associated with Indonesia project of $24,644 in 2009. There were no impairment write-downs in 2010. In 2009 the Company recorded write-downs resulting from ceiling test limits of $19,798,390. In 2010 we did not record any write downs in connection with ceiling test limits.

Table of Contents

Unproved Oil and Gas Properties United States As GeoPetro s properties are evaluated through exploration, they will be included in the amortization base. Costs of incurred in connection with unproved properties in the United States during the year ended December 31, 2010 consisted primarily of exploration costs in connection with GeoPetro s California prospect. Unproved properties in the United States as of December 31, 2010 and 2009 consist primarily of exploration costs related to our Alaska prospect. The prospects and their related costs in unproved properties have been assessed individually and no impairment charges were considered necessary for the United States properties for any of the periods presented. The current status of these prospects is that seismic data is being interpreted on an on-going basis on the subject lands within the prospects. Drilling on the California prospect is expected to commence in 2012 and 2013, and is expected to continue in future periods. (Note 12)

Sale of Alaskan Leases: 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 acquired all of the Alaskan Leases for the following consideration:

- a cash payment of $1.0 million;

- a $4.0 million payment from the first 75% of 8/8ths of the proceeds from any oil or gas production from the underlying leases;

- subsequent to our receipt of the $4.0 million payment specified above, we will thereafter receive an over-riding 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 on conventional oil and gas production and coal bed methane production; and

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

On October 21, 2010 The LEA #1 exploration well was spudded to evaluate a conventional oil and gas prospect identified and developed by us. On February 10, 2011, the Operator of the Alaska Leases in the Cook Inlet region, reported that their analysis has confirmed that the LEA #1 well penetrated three significant sand formation intervals that appear to be gas charged and that LEA #1 gas samples have confirmed 99% to 100% purity of dry natural gas. The Operator has reported that they are aiming to have a Flow Test Rig on site in late March 2011. Linc Energy has stated that it will now prepare for phase two of its Alaskan natural gas drilling program in the Trading Bay Block leases which are located on the northwest side of the Cook Inlet approximately 70 miles from the site of LEA #1.

Unproved Oil and Gas Properties Australia Unproved costs incurred in Australia represent costs in connection with the exploration of two exploration permit areas in Australia. The prospects and their related costs in unproved properties have been assessed individually and no impairment charges were considered necessary for the Australian properties for any of the periods presented. On June 20, 2007, the Company entered into a contract to sell its Australian Properties to an unaffiliated third party. These costs remaining in unproved properties represent our retained interest.

Unproved Oil and Gas Properties Indonesia Unproved costs incurred in Indonesia represent costs in connection with one production sharing contract area and the exploration efforts in Indonesia. The prospect and its related costs in the unproved properties have been assessed individually and no impairment charges were considered necessary for the Indonesian property for any of the periods presented. Currently, seismic data is being interpreted on an on-going basis to identify drilling locations on the subject lands within the prospect. Drilling was commenced on the prospect in early 2007 and is expected to continue in future periods.

The Company retains a carried 12% stake in the Bengara (II) Block PSC through its subsidiary, Continental-GeoPetro (Bengara-II) Ltd. (CGB2), the operator company of the project with offices in Jakarta, Indonesia. GeoPetro s partner, Continental Energy Corporation likewise retains an 18% interest in the Bengara (II) Block. CNPCHK (Indonesia) Limited owns the remaining 70% in the Bengara (II) Block and has paid 100% of the cost of drilling certain exploratory and appraisal wells.

In the event that the Company does not establish commerciality and provided that no extensions are granted for establishing commerciality, the Company would be required to forfeit its interest in the production sharing contract. If the Company forfeits its interest, it will be necessary to record an impairment write-down equal to the capitalized costs recorded for the area forfeited.

In 2009, C-G Bengara received an extension to the Bengara-II PSC contract until December 4, 2011 and may be extended for subsequent years subject to further approval based on an annual review of progress and results of appraisal work.

Table of Contents

Breakdown of Unproved Oil and Gas Properties The following table sets forth a summary of oil and gas property costs not being amortized at December 31, 2010, by the period in which the costs were incurred:

	Totals	Year Ended December 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008	2007 and Prior Years
Unproved property acquisition	$ 2,150,134	$	$	$	$ 2,150,134
Exploration	5,462,873	201,234	573,531	2,625,130	2,062,978
Total	$ 7,613,007	$ 201,234	$ 573,531	$ 2,625,130	$ 4,213,112

Management expects that planned activities for the year 2011 will enable the evaluation of approximately 25% of the costs as of December 31, 2010. Evaluation of 30% of the remaining costs is expected to occur in 2012 with the remaining 45% in 2013 and beyond.

GAS PROCESSING PLANT

There are asset retirement obligations associated with the Plant. However, components of the Plant can be used for extended and indeterminate periods of time as long as they are properly maintained and/or upgraded. GeoPetro s intent is to maintain the Plant assets and continue making improvements to those assets based on technological advances. As a result, GeoPetro s management believes that the Plant has an indeterminate life for purposes of estimating asset retirement obligations because dates or ranges of dates upon which GeoPetro would retire the Plant cannot reasonably be estimated.

5. DEBT

Debt at December 31, 2010 and December 31, 2009 consisted of the following:

	December 31, 2010	December 31, 2009
Current Portion		
Promissory notes 12/08 (a)	$ 200,000	$
Bridge notes 08/09, 09/09, 10/09 (d)	900,000	1,000,000
Bank of Oklahoma loan (e)	600,000	600,000
Promissory notes 12/10 (f)	300,000	
Promissory note 09/10 (g)	75,000	
Less discount on promissory notes	(93,737)	(50,171)
Net current notes payable	1,981,263	1,549,829
Long Term		
Promissory notes 12/08 (a)	850,000	1,050,000
Promissory notes 05/09 (b)	365,000	365,000
Promissory notes 06/09 (c)	300,000	300,000
Bank of Oklahoma loan (e)	3,772,847	4,372,847

Promissory note 09/10 (g)		300,000		
Less discount on promissory notes		(100,260)		(101,202)
Net Long term notes payable		5,487,587		5,986,645
Total	$	7,468,850	$	7,536,474

(a) During December 2008, the Company issued four promissory notes totaling $1,050,000 with maturity dates in December 2011. The notes may be repaid at any time without penalty. The notes bear an annual rate of eight percent (8%), with such interest payable quarterly in arrears. The principal amount and accrued and unpaid interest were initially due and payable in December 2011. In connection with the notes, the Company paid loan origination fees totaling $6,000 and granted three-year exercisable warrants to purchase 105,000 Common Shares and reissued 15,000 warrants at $1.00 per share. We also issued 150,000 warrants as a finder s fee. The fair value of the warrants on the dates of issuance of $122,764 and the $6,000 of loan origination fees, were recorded as a debt discount and are being amortized over the life of the promissory note. In February 2011, we extended the maturity on three separate notes totaling $850,000 to December 2012 (Note 11). In connection with the extension, the Company extended the warrants to purchase our common stock

Table of Contents

associated with these three notes for an additional year. The fair value associated with the warrant extension is immaterial. As of December 31, 2010 the unamortized portion of the debt discount was $42,556.

(b) During May 2009, the Company borrowed $365,000 pursuant to two separate three-year loans. The notes initially had maturity dates in May 2012. The notes may be repaid at any time without penalty. The notes bear an annual rate of eight percent (8%), with such interest payable quarterly in arrears. The principal amount and accrued and unpaid interest were initially due and payable on May 2012. In connection with the notes, the Company granted three-year exercisable warrants to purchase 36,500 Common Shares at $1.00 per share. The fair value of the warrants on the dates of issuance of $12,724, was recorded as a debt discount and is being amortized over the life of the promissory note. In February 2011, we extended the maturity of the notes through May 2013 (Note 11). In connection with the extension, the Company extended the warrants to purchase our common stock associated with these two notes for an additional year. The fair value associated with the warrant extension is immaterial. As of December 31, 2010 the unamortized portion of the debt discount was $5,832.

(c) In June 2009, the Company borrowed $300,000 pursuant to two separate one-year loans. The two notes initially had maturity dates in June 2010. The notes may be repaid at any time without penalty. The notes bear an annual rate of eight percent (8%), with such interest payable quarterly in arrears. The principal amount and accrued and unpaid interest were initially due and payable in June 2010. In connection with the notes, the Company had initially granted three-year exercisable warrants to purchase 30,000 Common Shares at $1.00 per share. The fair value of the warrants on the date of issuance of $7,537, was recorded as a debt discount and is being amortized over the life of the promissory note. In March 2010, these two notes were extended for an additional one year and the new maturity dates were in June 2011. In February 2011, (Note 11) two notes were extended for an additional one year and the new maturity dates were in June 2012. In connection with the extension, the Company extended the warrants to purchase our common stock associated with these two notes for an additional year. The fair value associated with the warrant extension is immaterial. As of December 31, 2010 the unamortized portion of the debt discount was $1,884.

(d) During August through October 2009, the Company borrowed an aggregate of $1,000,000 pursuant to five separate one-year bridge loans. The notes initially had maturity dates in August 2010 and October 2010. The notes may be repaid at any time without penalty. The notes bear at an annual rate of ten percent (10%), with such interest payable at maturity. In connection with the notes, the Company granted three-year warrants exercisable to purchase 50,000 Common Shares at $1.00 per share. The fair value of the warrants on the dates of issuance, $25,367, was recorded as a debt discount and is being amortized over the life of the bridge note. During August through October 2010, we fully repaid a promissory note in the amount of $50,000, and we partially repaid a promissory note in the amount of $50,000. We renewed three promissory notes with August 2011 maturity dates in the amount of $100,000, $30,000, and $50,000 and renewed one promissory note in the amount of $720,000 with a maturity date of October 2011. Prior to the note renewals we repaid all outstanding accrued interest on the notes. The terms of the renewed notes payable remain materially consistent those previously issued. In connection with the issuance of these notes we issued a total of 95,000 warrants to purchase our common stock (Note 9) and recorded $36,000 in renewal fees. The fair value of the warrants on the date of issuance of $25,887, and the $36,000 renewal fees, were recorded as a debt discount and is being amortized over the life of the promissory note. As of December 31, 2010 the unamortized portion of the debt discount was $44,487.

(e) Effective December 31, 2008, 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. At December 31, 2009, the interest rate was 5.78% (LIBOR + 5.5%). 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 pay, at the time the loan is repaid in full, a loan origination fee of $60,000 for any annual period during which the loan principal remains outstanding. There is no prepayment penalty. The Amended and Restated Term Loan Agreement 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 $35,000,000. In March 2010, BOK waived compliance of certain covenants of the loan, and lowered the minimum tangible net worth requirement from the current $35 million to $18 million, the terms of the waiver relate to all periods subsequent to December 31, 2009. At December 31, 2010, the interest rate was approximately 6% (LIBOR + 5.5%), and we were in compliance with all covenants of the loan. In March 2011, the Company modified its bank loan with Bank of Oklahoma, the Fourth Amendment of the Amended and Restated Term Loan Agreement which extends the loan by an additional year so as to have new maturity date being December 31, 2012. The terms of the 4th amendment provide for minimum quarterly principal payments of $150,000, minus $150,000 times a fraction, the numerator of which is the sum of all principal payments made by us after March 15, 2011 but prior to such payment date, and the denominator of which is $4,552,847. The loan fee of $180,000 will be added to the principal balance. The interest is payable quarterly in arrears at prime plus 3.25% or Libor plus 4.75% at the option of the Company. The agreement contains customary affirmative and negative covenants including restrictions on incurring debt in the amount in excess of $375,000. (Note 11)

Table of Contents

(f) In December 2010, we issued 1-year notes payable at 6% per annum in the amount of $300,000 with maturity dates of December 31, 2011. The notes are secured by the Swan Hills Project in Canada. In connection with the notes, the Company granted three-year exercisable warrants to purchase 75,000 shares of Common Shares at $0.50 per share. The fair value of the stock purchase warrants issued in connection with this note of $16,662, was recorded as a debt discount and is being amortized over the life of the promissory note. As of December 31, 2010 the unamortized portion of the debt discount was $16,304.

(g) In September 2010, we issued a 5-year non-interest bearing note payable in the amount of $375,000 in connection with the execution of a settlement agreement. Payments are due as follows: $25,000 in March 2011, $50,000 in October 2011, and $75,000 each October thereafter until 2015. An imputed interest rate of 10% per annum has been used to record a discount in connection with this note of $90,116, and is being amortized over the life of the note. As of December 31, 2010 the unamortized portion of the debt discount was $82,934.

As schedule of Maturities of our Debt Obligations as of December 31, 2010 is as follows;

Maturity Date	**2011**	**2012**	**2013**	**2014**	**2015**
May	$	$ 365,000	$	$	$
June	300,000				
August	180,000				
October	795,000	75,000	75,000	75,000	75,000
December	5,722,847				
Totals	$ 6,997,847	$ 440,000	$ 75,000	$ 75,000	$ 75,000

6. INCOME TAXES

The Company files income tax returns in the U.S. federal jurisdiction and various states. There are currently no federal or state income tax examinations underway. Furthermore, the Company is no longer subject to U.S. federal income tax examinations by the Internal Revenue Service for tax years before 2007 and for state and local tax authorities for tax years before 2006. The Company does, however, have net operating losses generated in tax years 1997 and after, which remain open for examination.

The Company adopted the provisions of ASC 740 (formerly SFAS 109 and FIN 48), on January 1, 2007. As of December 31, 2007 the Company had no unrecognized tax benefits. There have been no changes during the year with respect to unrecognized tax benefits. The Company does not foresee the total amounts of unrecognized tax benefits significantly increasing within the next 12 months. Furthermore, no corresponding interest and penalties have been accrued as the Company is in a net operating loss position.

ASC 740 requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the financial statement carrying amounts and the tax basis of the assets and liabilities. Where it is more likely than not that a tax benefit will not be realized, a valuation allowance is recorded to reduce the deferred tax asset to its realizable value.

A valuation allowance has been provided against the Company s net deferred tax assets as the Company believes that it is more likely than not that the net deferred tax assets will not be realized.

Table of Contents

The effective tax rate for the year ended December 31, 2010 is negligible.

The provision for income taxes consists of the following:

	2010	2009
Current		
Federal	$	$
State	800	2,100
Foreign		
Total	800	2,100
Deferred		
Federal		
State		
Foreign		
Total		
Total Income Tax Provision	$ 800	$ 2,100

The actual income tax (benefit) expense differs from the expected tax (benefit) expense as computed by applying the U.S. Federal corporate income tax rate of 35% for each period as follows:

	2010	2009
Amount of expected tax (benefit) expense	$ (1,728,000)	$ (9,096,000)
Non-deductible expenses	8,000	69,000
Alternative minimum tax		
State Taxes	800	2,100
Other		
Valuation allowance adjustments	1,720,000	9,027,000
	$ 800	$ 2,100

Deferred income taxes reflect the net tax effects of temporary differences between carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the Company s deferred tax assets (liabilities) are as follows:

	2010	2009
Deferred tax assets (liabilities)		
Net operating loss carry forwards	$ 12,785,000	$ 10,460,000
Oil and gas property basis differences	2,415,000	2,795,000
Credit carryforwards		
Stock compensation	476,000	330,000
Other	(749,000)	(749,000)
Total deferred tax assets	14,927,000	12,836,000
Valuation allowance	(14,927,000)	(12,836,000)
Total net deferred taxes	$	$

As of December 31, 2010, GeoPetro had net operating loss (NOL) carryforwards of approximately $37,234,000 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 $11,872,000 of California net operating losses and approximately $670,000 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.

7. SHAREHOLDERS EQUITY

GeoPetro s articles of incorporation allow for the issuance of 100,000,000 shares of common stock, 1,000,000 shares of Series A preferred stock (Series A Stock), 5,000,000 shares of Series AA preferred stock (Series AA Stock), and an additional 44,000,000 shares of preferred stock which may be issued from time to time in one or more series, with such rights and preferences as determined by our Board of Directors.

Common Stock The holders of our common stock are entitled to one vote per share. Subject to preferences on outstanding preferred stock, the holders of common stock are entitled to receive ratably such dividends as may be declared by the board of directors. In the event of a liquidation, the holders of common stock and Series A preferred stock are entitled to share ratably in all assets remaining after payment of liabilities, subject to prior distribution rights of preferred stock.

In September and October 2010, we completed a sale through a private placement transaction to certain institutional and individual accredited investors. Units were priced at $0.48 per unit, and each unit consisted of one share of no par value common stock, and a one-half common share purchase warrant. Each one whole warrant entitles the holder to acquire one common share at a price of $0.75 per share for a period of three years. The total aggregate purchase price for the units sold was $1,773,600, and represented the sale of 3,695,000 common shares and 1,847,500 warrants. (Note 9) We granted piggyback registration rights to the investors with respect to the shares of common stock and common stock issuable upon exercise of the Warrants which the investors acquired in the transaction. The Company paid no fees or commissions in connection with the sale of the units.

On December 30, 2010, we completed a sale through a private placement transaction to certain institutional and individual accredited investors. Units were priced at $0.45 per unit and each unit consisted of one share of no par value common stock, and one-half common share purchase warrant. Each one whole warrant entitles the holder to acquire one common share at a price of $0.75 per share for a period of three years. The total aggregate purchase price was $500,038 and represented the sale of 1,111,199 common shares and 555,596 warrants to acquire common shares. (Note 9) We granted piggyback registration rights to the investors with respect to the shares of common stock and common stock issuable upon exercise of the warrants which the investors acquired.

Series B Preferred Stock As of December 31, 2010, there are 7,523,000 shares of Series B Stock issued and outstanding. 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 2010 and 2009, we incurred $451,380 and $179,045 in dividends on the Series B Stock, respectively, of which $448,070 and $68,583 had been paid as of December 31, 2010 and 2009, respectively.

Subsequent to December 31, 2010, a holder of 20,000 shares of the Company s Series B Preferred Stock converted shares on a one-for-one basis into fully paid and non-assessable shares of the Company s Common Stock. (Note 11)

8. COMMON STOCK OPTIONS

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

Table of Contents

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); and

- 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.

On July 19, 2010, we modified the original exercise price for 740,000 stock options from $4.28 as issued on June 27, 2008 to $0.50 per share. We considered ASC 718 *Share Based Compensation* when recording the impact of this re-pricing. The additional compensation cost to be recognized in connection with the re-pricing of these options is $113,882 and will be recognized over the requisite service periods of the underlying options.

On July 19, 2010, we granted a total of 195,000 stock options to five non-management directors at an exercise price of $0.50 per share. These options will vest ratably over five years pursuant to the terms of the 2004 Stock Option and Appreciation Rights Plan. The grant date fair value of the options was $59,984.

The Company recorded stock compensation expense of $424,502 and $403,963 for the twelve months period ended December 31, 2010 and 2009, respectively.

A summary of the status of GeoPetro s stock option plan is as follows:

	Options	Exercise Prices		Weighted Average Exercise Price
Outstanding at January 1, 2009	2,740,000	$2.10 to $6.25	$	2.87
Granted	60,000	$1.00		1.00
Exercised				
Canceled	(80,000)	$4.28		4.28
Outstanding at December 31, 2009	2,720,000	$1.00 to $6.25		2.73
Granted	195,000	$0.50		0.50
Exercised				
Expired	(20,000)	$4.25 to $6.25		5.25
Outstanding at December 31, 2010	2,895,000	$0.50 to $3.85	$	1.59

We estimated the fair values of each option granted using the Black-Scholes model with the following assumptions for options granted during the years ended December 31:

Table of Contents

	2010		2009
Expected dividend yield			
Expected volatility		111.7%		113.0%
Risk-free interest rates		0.95%		2.53%
Expected lives		5 years		5 years
Weighted average fair values per share	$	0.31	$	0.33

We estimated the dividend yield at 0% considering that we have not historically paid dividends on our common stock, nor do we expect to pay dividends in the foreseeable future. Volatility estimates represent the historic trading volatility underlying our common stock at the date of grant. We estimated risk-free interest rates based on the U.S. Treasury yield curve at the date of grant. Expected lives are based on our historic experience with employee option exercise behavior and consider the vesting period and the contractual lives of the related options.

The options outstanding as of December 31, 2010 have the following contractual lives:

Number of Options Outstanding	Number of Options Exercisable	Exercise Prices	Weighted Average Remaining Contractual Life
935,000	296,000	0.50	3.09
210,000	162,000	1.00	3.26
1,600,000	1,600,000	2.10	2.36
150,000	120,000	3.85	0.29
2,895,000	2,178,000		

The total intrinsic value of options outstanding was $nil at December 31, 2010 and 2009, respectively. The intrinsic value for exercisable options was $nil at December 31, 2010 and 2009, respectively.

As of December 31, 2010, there are 2,178,000 options which are exercisable. The remaining 717,000 options will become exercisable over the next four years. The stock compensation expense related to the unvested awards is $980,652.

9. COMMON STOCK WARRANTS

On December 23, 2010 we issued 75,000 warrants to purchase our common shares at $0.50 in conjunction with the issuance of a new promissory note payable. (Note 5) The warrants expire as of December 23, 2013. The total fair value of the warrants as calculated using the Black - Scholes pricing model was $14,192.

In September and October, 2010, we issued 95,000 warrants to purchase our common shares at $0.50 in connection with the renewal of four of our promissory notes payable (Note 5). The warrants expire as of August 2013 and October 2013, respectively. The total fair value of the warrants as calculated using the Black - Scholes pricing model was $23,286.

During September through December 2010, we issued 2,403,096 warrants to purchase our common shares at $0.75 in connection with two private placements of our common stock (Note 9). The warrants expire on September 30, 2013 and December 30, 2013, respectively.

The fair value of the warrants is calculated using the Black-Scholes pricing model. Key assumptions used in valuing the warrants included: an estimated dividend yield of 0%; volatility of between 72% to 122%; an estimated risk-free interest rate based on the U.S. Treasury yield curve at the date of grant of between 0.51% to 1.10%; and an expected life of three years.

During October 2009, the Company issued warrants to purchase 157,690 shares of common stock to a non-related parties expiring September 30, 2011 and October 19, 2014, with a strike price of $1.00 per share. The grant-date fair value of the warrants amounted to $97,144, using the Black-Scholes valuation method, was recorded as finder s fee and offset additional paid in capital.

On April 10, 2009, the Company extended the expiration date on a warrant to purchase 114,000 shares of common stock (exercisable at $3.50 per share) to December 15, 2011. The fair value of the warrant extension was insignificant.

On March 31, 2009, the Company extended the expiration date on a warrant to purchase 100,000 shares of common stock (exercisable at $5.25 per share) to March 31, 2014. The fair value of the warrant extension was insignificant.

Table of Contents

On February 23, 2009 and October 8, 2009, the Company issued warrants to purchase 98,500 shares of common stock to a non-related party expiring February 22, 2012 and October 18, 2012 with a strike price of $1.00 to $1.25 per share. Warrants granted shall vest according the following schedule: 25% immediately; 25% at the three month anniversary of the signing of the agreement; 25% at the six month anniversary of the signing of the agreement; and 25% at the nine month anniversary of the signing of the agreement. The grant-date fair value of the warrants amounted to $55,893 using the Black-Scholes valuation method, which is recognized in general and administrative expense on our consolidated statement of operations ratably over the requisite service period as defined by the vesting schedule above.

The following table summarizes the number of shares reserved for the exercise of common stock purchase warrants as of December 31, 2010:

Expiration Date		Exercise Price	Outstanding at 12/31/2009	Warrants Exercised	Warrants Granted	Warrants (Expired/Canceled)	Outstanding at 12/31/2010
01/31/10	$	3.50	80,000			(80,000)	
08/13/10	$	3.85	60,078			(60,078)	
09/30/11	$	1.00	27,150				27,150
12/15/11	$	3.50	114,000				114,000
12/22/11	$	1.00	35,000				35,000
12/23/11	$	1.00	45,000				45,000
12/25/11	$	1.00	40,000				40,000
02/22/12	$	1.00	50,000				50,000
01/02/12	$	1.00	150,000				150,000
05/17/12	$	1.00	36,500				36,500
06/29/12	$	1.00	30,000				30,000
08/13/12	$	4.50	600,779				600,779
09/30/12	$	1.00	14,000				14,000
10/22/12	$	1.00	36,000				36,000
11/22/12	$	1.25	12,500		37,500		50,000
08/31/13	$	0.50			23,000		23,000
09/29/13	$	0.75			1,847,500		1,847,500
10/30/13	$	0.50			72,000		72,000
12/23/13	$	0.50			75,000		75,000
12/30/13	$	0.75			555,596		555,596
03/31/14	$	5.25	100,000				100,000
10/19/14	$	1.00	130,540				130,540
			1,561,547		2,610,596	(140,078)	4,032,065

The following table summarizes the number of shares reserved for the exercise of common stock purchase warrants as of December 31, 2009:

Expiration Date		Exercise Price	Outstanding at 12/31/2008	Warrants Exercised	Warrants Granted	Warrants (Expired/Canceled)	Outstanding at 12/31/2009
01/31/09	$	3.50	150,000			(150,000)	
02/12/09	$	3.50	20,000			(20,000)	
02/28/09	$	4.51	5,000			(5,000)	
01/31/10	$	3.50	80,000				80,000
08/13/10	$	3.85	60,078				60,078
09/30/11	$	1.00			27,150		27,150
12/15/11	$	3.50	114,000				114,000

12/22/11	$	1.00	35,000			35,000
12/23/11	$	1.00	45,000			45,000
12/25/11	$	1.00	40,000			40,000
02/22/12	$	1.00		50,000		50,000
01/12/12	$	1.00		150,000		150,000
05/17/12	$	1.00		36,500		36,500
06/29/12	$	1.00		30,000		30,000
08/13/12	$	4.50	600,779			600,779
09/30/12	$	1.00		14,000		14,000
10/22/12	$	1.00		36,000		36,000
11/22/12	$	1.25		12,500		12,500
03/31/14	$	5.25	100,000			100,000
10/19/14	$	1.00		130,540		130,540
			1,249,857	486,690	(175,000)	1,561,547

F-20

Table of Contents

10. COMMITMENTS AND CONTINGENCIES

Employment Agreements The Company entered into a contract of employment with Stuart J. Doshi, Founder, President, Chief Executive Officer and Chairman of the Board of Directors, as amended through December 31, 2008. The contract, as amended, provides for a five-year term commencing May 1, 2005 which term is automatically extended for successive two-year renewal terms unless: (a) the board of directors elects not to renew the contract and the Company provides notice to Mr. Doshi of such non-renewal at least six months prior to the expiry of his employment term or any renewal term, or (b) Mr. Doshi attains age 75, in which case the term ends upon the completion of the calendar year in which he becomes 75 years old unless the Company and Mr. Doshi mutually agree to one-year extensions. The contract of employment currently provides for an annual base salary of $300,000 and further provides that in the event of a change of control of the Company or if Mr. Doshi is terminated without cause, he is entitled to receive (a) in exchange for all of his vested stock options and vested restricted shares, such number of Common Shares having a market value equal to the difference between (x) the aggregate total market value of all vested restricted shares and Common Shares he would receive upon exercise of all vested stock options less (y) the aggregate total exercise price for all of his vested stock options; provided, however, that if the Common Shares to be delivered to Mr. Doshi upon such change of control or termination have not been registered so as to permit immediate public resale, Mr. Doshi shall instead receive a cash payment equal to the market value on the date of termination of all vested stock options and restricted shares without any discount for liquidity or minority position against cancellation of such options and restricted shares, (b) a cash payment equal to the greater of (i) his compensation for the remainder of his term, including salary and the aggregate amount of his bonuses in respect of the last four fiscal years and (ii) four times his compensation in the current year, including his then-current salary and the average amount of his bonuses for the last four fiscal years, and (c) an additional cash payment representing his employment benefits equal to 20% of the amount of salary he is entitled to receive under (b)(i) or (b)(ii) above, as applicable. In addition, in the event of a change of control or termination without cause, all unvested options issued by the Company to Mr. Doshi will vest.

GeoPetro has executed an employment contract as amended through December 31, 2010 with its Vice President of Exploration, David V. Creel. The contract provides an annual salary of $163,200 and may be terminated by GeoPetro without cause upon the payment to Mr. Creel of cash payments equal to the lesser of three months base salary or base salary during the remainder of the employment term, and, in the event of termination without cause, all unvested options issued by GeoPetro to Mr. Creel will vest. Mr. Creel is currently on a month-to-month employment basis.

Office Lease 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 as of December 31, 2010 are as follows:

2011		145,635
2012		149,836
2013		154,037
2014		158,238
2015		162,439
2016		166,640
2017		56,013
Total	$	992,838

Rent expense for the years ended December 31, 2010 and 2009, was approximately $127,594 and $90,651, respectively, and is included in general and administrative expenses in the accompanying statements of operations.

Madisonville Net Profits Interest Redwood LP s 100% working interest is subject to a net profits interest in favor of unrelated third parties. The net profits interest is 12.5% (proportionately reduced) of the net operating profits until payout is achieved. After

Table of Contents

payout, the net profits interest increases to 30% (proportionately reduced). Payout, for purposes of the net profits interest, is defined and achieved at such time as Redwood LP has recouped from net operating cash flows its total net investment in the project plus a 33% cash on cash return.

Devon Lawsuit -On September 11, 2009, the Company s subsidiary, Redwood Energy Production, L.P. (Redwood) filed an Original Petition for Declaratory Judgment against Devon Energy Production Company (Devon) regarding certain over-riding royalty interests and related revenue amounts claimed by Devon. In the context of this lawsuit, Devon has asserted a claim for the past due royalties held by Redwood in a suspense account. The Company previously accrued all amounts owed pursuant to these over-riding royalty interests as royalty owners payable. On September 30, 2010, we entered into a settlement agreement with Devon related to over-riding royalty interests and related revenue amounts claimed by Devon. Prior to the settlement we had accrued $767,635 as royalties payable to Devon. In connection with the settlement agreement we issued a 5-year non-interest bearing note in the amount of $375,000, (Note 5) and agreed to pay $300,000 on October 1, 2010. We have recorded a gain on the settlement of $182,751 which has been included in other income on our consolidated statement of operations. Of the gain recognized $90,116 relates to imputed interest which will be recognized as expense over the term of the note.

11. SUBSEQUENT EVENTS

The Company has evaluated subsequent events through the date on which these financial statements were initially filed.

In January 2011, we entered into a sublease agreement whereby a portion of the Company s principal executive offices have been leased to a third party. The terms of the sublease agreement indicate a seventy-five month term cancelable by either party with ninety days written notice after December 31, 2011. The Company will recoup approximately 50% of the base rental obligation on its principal executive offices through the sublease agreement.

In February 2011, we extended the maturity on three separate notes totaling $850,000 to December 2012 (Note 5). In connection with the extension, the Company extended the warrants to purchase our common stock associated with these three notes for an additional year.

In February 2011, we extended the maturity of the two notes totaling $365,000 through May 2013 (Note 5). In connection with the extension, the Company extended the warrants to purchase our common stock associated with these two notes for an additional year.

In February 2011, we extended the maturity of two notes totaling $300,000 through June 2012 (Note 5). In connection with theextension, the Company extended the warrants to purchase our common stock associated with these two notes for an additional year.

In February 2011, Stuart J. Doshi, President and CEO, advanced $125,000 to the Company. The note bears interest at 8% per annum and is payable on demand.

During February and March 2011, GeoPetro completed a private placement transaction. The total placement consisted of 2,050,328 units priced at $0.45 per unit. Each unit consisted of one share of no par value common stock, and a one-half common share purchase warrant. Each warrant entitles the holder to acquire one common share at a price of $0.75 per share for a period of three years. The total aggregate purchase price for the units sold was $922,648, and represented the sale of 2,050,328 common shares and 1,025,164 warrants to purchase our common stock.

In March 2011, the Company modified its bank loan with Bank of Oklahoma, the Fourth Amendment of the Amended and Restated Term Loan Agreement which extends the loan by an additional year so as to have a the new maturity date being December 31, 2012. The terms of the 4th amendment provide for minimum quarterly principal payments of $150,000, minus $150,000 times a fraction, the numerator of which is the sum of all principal payments made by us after March 15, 2011 but prior to such payment date, and the denominator of which is $4,552,847. The loan fee of $180,000 will be added to the principal balance. The interest is payable quarterly in arrears at prime plus 3.25% or Libor plus 4.75% at the option of the Company. The agreement contains customary affirmative and negative covenants including restrictions on incurring debt in the amount in excess of $375,000.

In March 2011, a holder of 20,000 shares of the Company s Series B Preferred Stock, converted shares on a one-for-one basis into fully paid and non-assessable shares of the Company s Common Stock.

In March 2011 we formed GeoPetro Pacific LLC, a Delaware Limited Liability Company.

Table of Contents

12. SUPPLEMENTARY OIL AND GAS RESERVE INFORMATION: (UNAUDITED)

The reserve quantities and valuations are based upon estimates by MHA Petroleum Consultants. The proved reserves presented herein are located entirely within the United States. Proved reserves are the 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. 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. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Reservoirs are considered proved if economic productivity 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 reasonably be 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.

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas reserves 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.

The estimates included in the following tables are by their nature inexact and are subject to changing economic, operating and contractual conditions. At December 31, 2010, all of GeoPetro s reserves are attributable to two producing wells, one shut-in well and two undeveloped locations. Other than the producing wells and one shut-in well, there is no other production history as of or subsequent to that date. Reserve estimates for these wells are subject to substantial upward or downward revisions after production commences and a production history is obtained. Accordingly, reserve estimates of future net revenues from production may be subject to substantial revision from year to year. Reserve information presented herein is based on reports prepared by independent petroleum engineers.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect GeoPetro s expectations for actual revenues to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these are the basis for the valuation process.

Table of Contents

	Natural Gas (Mcf)
Proved Developed and Undeveloped Reserves	
January 1, 2009	20,470
Revisions of previous estimates	(6,280)
Extensions, discoveries, and other additions	5,249
Sale of reserves	
Production	(807)
December 31, 2009	18,632
Revisions of previous estimates	409
Extensions, discoveries, and other additions	
Sale of reserves	
Production	(733)
December 31, 2010	18,308

	2010 (MMcf)	2009 (MMcf)
Proved developed	2,423	3,651
Proved developed non-producing	7,049	6,610
Proved undeveloped	8,836	8,371
Total	18,308	18,632

Proved reserves presented herein are located entirely within in the United States

The following is a discussion of the material changes in our proved reserve quantities for the years ended December 31, 2010 and 2009.

Year Ended December 31, 2010

The upward revision of previous estimates of natural gas reserves during 2010 of 409 MMcf is attributable to increases in gas prices as calculated under the new SEC pricing methodology. Natural gas prices utilizing the new SEC price methodology increased approximately 30% from December 31, 2009 ($3.11 per mcf) to December 31, 2010 ($4.03 per mcf).

Year Ended December 31, 2009

The downward revision of previous estimates of natural gas reserves during 2009 of 6,280 MMcf is primarily associated with performance revisions attributable to the Fannin #1 well. The remainder of the downward revision of previous estimates is attributable to lower natural gas prices as calculated under the new SEC pricing methodology. Natural gas prices utilizing the new SEC price methodology decreased approximately 41% from December 31, 2008 to December 31, 2009, resulting in a decrease in proved reserves of approximately 505 MMcf.

The reserve increases resulting from extensions, discoveries and other additions resulted for two reasons. The first reason is that one probable location from the year end 2008 was reclassified to a proved undeveloped location in the year end 2009. 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 planned hydraulic fracture treatment for the existing Wilson #1 well, in conjunction with the necessary plant upgrade to handle the increased volume of gas, resulted in the Wilson#1 well reserves being reclassified into the proved undeveloped category because of the relatively large expense required to achieve the predicted production rates from this well.

Table of Contents

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

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 2010 and 2009 estimates were computed by applying the simple arithmetic average of the natural gas price in effect on the first day of each month to estimated annual future net production from proved gas reserves. For both 2010 and 2009, future development 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, 2010	2009
	(in thousands)	
Future cash inflows	$ 65,988	$ 50,652
Future production costs	(19,353)	(17,157)
Future development costs	(7,849)	(7,849)
Future income taxes		
Future net cash flows	38,786	25,646
10% annual discount	(9,684)	(6,005)
Standardized measure of discounted future net cash flows	$ 29,102	$ 19,641

The PV-10 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.

Changes in the Standardized Measure of Discounted Futures Net Cash Flows From Proved Petroleum and Natural Gas Reserve Quantities.

	Years Ended December 31, 2010	2009
Balance, beginning of period	19,641	47,315
Sales of oil and gas, net	(1,312)	1,373
Net change in prices and production costs	9,240	(32,319)
Net change in future development costs		(2,497)
Extensions and discoveries		7,229
Revisions of previous quantity estimates	625	(8,648)
Net change in income taxes		6,109
Accretion of discount	1,515	3,548
Other	(607)	(2,469)
Balance, end of period	$ 29,102	$ 19,641

Table of Contents

EXHIBIT INDEX

Exhibit Number	Description
3.1 (2)	Amended and Restated Articles of Incorporation of GeoPetro Resources Company
3.2 (4)	Second Amended and Restated Bylaws of the GeoPetro Resources Company
4.1 (2)	Form of Warrant issued by GeoPetro Resources Company to various investors on various dates.
4.2 (3)	Specimen Common Stock Certificate
4.3	Form of common stock purchase warrant issued to various investors dated August 13, 2007 (filed as exhibit 4.1 to the Company s Report on Form 8-K as filed with the Securities and Exchange Commission on August 16, 2007, and incorporated herein by reference)
4.4	Registration Rights Agreement between GeoPetro Resources Company and various investors dated August 13, 2007 (filed as Exhibit B to the Form of Unit Subscription Agreement dated August 13, 2007 filed as Exhibit 10.20 to the Company s Report on Form 8-K as filed with the Securities and Exchange Commission on August 16, 2007 and incorporated herein by reference)
4.5 (6)	Placement Agent Warrant dated August 13, 2007
4.6 (7)	Form of Common Stock Purchase Warrant dated as of various dates, issued to purchasers of promissory notes
4.7(15)	Unit Subscription Agreement and Common Stock Purchase Warrant, Dated September 30, 2010.
4.8(16)	Unit Subscription Agreement and Common Stock Purchase Warrant, Dated December 30, 2010.
10.1 (2)	Joint Venture Agreement Bengara II, Dated January 1, 2000
10.2 (2)	Production Sharing Contract Bengara II, Dated December 4, 1997
10.4 (2)	Exploration Permit#408, Dated July 2, 1997
10.5 (2)	Madisonville Field Development Agreement dated August 1, 2005
10.6 (2)	Alaska Cook Inlet Option dated April 20, 2005
10.7 (2)	The 2001 Stock Incentive Plan
10.8 (2)	The 2004 Stock Option and Appreciation Rights Plan
10.9 (2)	Stuart Doshi Employment Agreement, Dated July 28, 1997 (effective July 1, 1997) and amendments dated January 11, 2001, July 1, 2003, April 20, 2004, May 9, 2005, July 28, 2005 and January 30, 2006
10.10 (2)	David Creel Employment Agreement, Dated April 28, 1998 and amendments dated June 15, 2000, May 12, 2003 and January 1, 2005, April, 26, 2010
10.13 (4)	Form of Subscription Agreement for GeoPetro Resources Company stock executed by various investors on various dates.
10.19 (5)	Shares Sale & Purchase Agreement Dated September 29, 2006
10.20 (6)	Form of Unit Subscription Agreement Dated August 13, 2007
10.22 (6)	Promissory Note to Stuart Doshi dated February 12, 2007
10.23 (11)	Seventh Amendment to Employment Agreement of Stuart Doshi, dated December 29, 2008
10.24 (11)	Eighth Amendment to Employee Agreement of Stuart Doshi, dated December 31, 2008
10.25 (11)	Fourth Amendment to Employment Agreement of David Creel, dated December 29, 2008
10.26 (11)	Fifth Amendment to Employee Agreement of David Creel, dated December 31, 2008
10.29 (8)	Purchase and Sale Agreement dated December 31, 2008
10.30 (9)	Amended and Restated Term Loan Agreement Fourth Amendment dated December 31, 2008 with Bank of Oklahoma
10.31 (11)	Security Agreement dated December 31, 2008
10.32 (11)	Form of Promissory Note issued by GeoPetro Resources Company to various investors dated various dates from December 23, 2008 to December 26, 2008
10.24 (12)	Employment Agreement with J. Chris Steinhauser dated April 27, 2009
10.25 (13)	Sixth Amendment to David Creel Employment Agreement dated April 28, 2009
10.26 (14)	Related Party Promissory Note Dated June 18, 2009
21.1 (11)	List of subsidiaries of GeoPetro Resources
23.1 (1)	Consent of MHA Petroleum Consultants
23.2 (1)	Consent of Hein & Associates LLP
31.1 (1)	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
31.2 (1)	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
32.1 (1)	Certification of Chief Executive Officer and Chief Financial Officer of GeoPetro Resources Company pursuant to 18 U.S.C. § 1350.

99.1 (1)	Report of MHA Petroleum Consultants

Table of Contents

---

(1) Filed herewith.

(2) Filed as the identically numbered exhibit to the Registration Statement on Form S-1, (No. 333-135485), as filed with the

Securities and Exchange Commission on June 30, 2006, and incorporated herein by reference.

(3) Filed as the identically numbered exhibit to the Registration Statement on Form S-1, (No. 333-135485), as filed with the Securities and Exchange Commission on January 31, 2007, and incorporated herein by reference.

(4) Filed as the Exhibit 3(ii) to the Company s Report on Form 8-K as filed with the Securities and Exchange Commission on April 25, 2008, and incorporated herein by reference.

(5) Filed as the identically numbered exhibit to the Registration Statement on Form S-1 (No. 333-135485), as filed with the Securities and Exchange Commission on January 9, 2007, and incorporated herein by reference.

(6) Filed as the identically numbered exhibit to the Registration Statement on Form S-1 (No. 333-146557), as filed with the Securities and Exchange Commission on October 9, 2007, and incorporated herein by reference.

(7) Filed as Exhibit 4.1 to the Company s Report on Form 8-K, as filed with the Securities and Exchange Commission on January 7, 2009, and incorporated herein by reference.

(8) Filed as Exhibit 10.24 to the Company s Report on Form 8-K, as filed with the Securities and Exchange Commission on January 14, 2009, and incorporated herein by reference.

(9) Filed as Exhibit 10.25 to the Company s Report on Form 8-K, as filed with the Securities and Exchange Commission on January 14, 2009, and incorporated herein by reference.

(10) Filed as Exhibit 10.1 to the Company s Report on Form 8-K, as filed with the Securities and Exchange Commission on December 21, 2007, and incorporated herein by reference.

(11) Filed as Exhibit 23.1 to the Company s Report on Form 10-K, as filed with the Securities and Exchange Commission on March 23, 2009, and incorporated herein by reference.

(12) Filed as Exhibit 10.24 to the Form 10-Q, as filed with the Securities and Exchange Commission on May 11, 2009, and incorporated herein by reference.

(13) Filed as Exhibit 10.25 to the Form 10-Q, as filed with the Securities and Exchange Commission on May 11, 2009, and incorporated herein by reference.

(14) Filed as Exhibit 10.26 to the Form 10-Q, as filed with the Securities and Exchange Commission on August 10, 2009, and incorporated herein by reference.

(15) Filed as Exhibits 4.1 and 4.2 to the Company s Report on Form 8-K as filed with the Securities and Exchange Commission on October 6, 2010.

(16) Filed as Exhibits 4.1 and 4.2 to the Company s Report on Form 8-K as filed with the Securities and Exchange Commission on March 4, 2011.

Indicates a management or compensatory plan or arrangement.
