Enhanced Oil Resources Inc.

Management's Discussion & Analysis

Six Months Ended June 30, 2009

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Management's Discussion and Analysis and in certain documents incorporated by reference into this Management's Discussion and Analysis, constitute forward-looking statements. These statements relate to future events or the Company's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar other expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes that the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Management's Discussion and Analysis should not be unduly relied upon. These statements speak only as of the date of this Management's Discussion and Analysis, as the case may be. The Company does not intend, and does not assume an obligation, to update these forward-looking statements, except as required by securities law.

In particular, this Management's Discussion and Analysis and the documents incorporated by reference contain forward-looking statements pertaining to the following:

- *the quantity of reserves;*
- *crude oil, natural gas, CO_2 and helium production levels;*
- *capital expenditure programs;*
- *projections of market prices and costs;*
- *supply and demand for crude oil , natural gas, CO_2 and helium;*
- *expectations regarding the Company's ability to raise capital and to continually add to reserves through acquisitions and development; and*
- *treatment under government regulatory and taxation regimes.*

The Company's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Management's Discussion and Analysis:

- *volatility in market prices for oil and natural gas;*
- *liabilities and risks inherent in oil and natural gas operations;*
- *uncertainties associated with estimating reserves;*
- *competition for, among other things, capital, acquisitions of reserves, undeveloped lands and*
- *skilled personnel;*
- *incorrect assessments of the value of acquisitions; and*
- *geological, technical, drilling and processing problems.*

ABBREVIATIONS

Crude Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
BBls/d	barrels per day
BOPD	barrels of oil per day
MMbbls	million barrels
Mbbls	thousand barrels

Carbon Dioxide and Natural Gas

Bcf	billion cubic feet
CO_2	carbon dioxide
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
Tcf	trillion cubic feet

API	American Petroleum Institute
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of one boe for six mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
Contingent resource	Those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable.
DOE	United States Department of Energy
EOR	Enhanced oil recovery, typically any method of economically removing oil incremental to that produced by primary or conventional improved-recovery methods
MBOE	1,000 barrels of oil equivalent
NI 51-101	National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities adopted by the Canadian Securities Administrators
OOIP	Original oil in place
Primary recovery	Production in which only existing natural energy sources in the reservoir provide for movement of well fluids.
Permian Basin	A large crude oil and natural gas producing area representing a sedimentary basin dating from the Permian geologic period and covering an area extending from West Texas to eastern New Mexico
Reserves	Estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward based on (i) analysis of drilling, geophysical and engineering data; (ii) the use of established technology; (iii) specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed; and (iv) a remaining reserve life of 50 years. These definitions and disclosures are in accordance with the definitions, procedures and standards contained in the Canadian Oil and Gas Evaluation (COGE) Handbook and the Canadian Securities Administrators NI 51-101.
Secondary recovery	Any method by which an essentially depleted reservoir is restored to producing status by the injection of liquids or gases (from external sources) into the formation, thereby effecting a restoration of reservoir energy which moves the unrecoverable secondary reserves through the reservoir to the wellbore
US $	United States dollars
WTI	West Texas Intermediate, the reference price paid in US dollars at Cushing, Oklahoma for crude oil of standard grade

Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six Mcf equivalent to one Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The Company

Enhanced Oil Resources Inc. ("we" or the "Company") is a natural resource company incorporated in 1980 and currently engaged in the acquisition, exploration and development of natural resource properties in the Southwestern United States. In June 2007, the Company changed its name to Enhanced Oil Resources Inc. and its stock trading symbol to "EOR" to reflect a change in the Company's added focus on the development of enhanced recovery activities, principally, techniques of CO_2 injection used to increase an oil field's ultimate oil recovery and extend an oil field's productive life. The Company's head office is in Houston, Texas. Common shares of the Company are listed and posted for trading on the TSX Venture Exchange ("TSX-V") under the symbol "EOR". The following Management Discussion and Analysis ("MD&A") should be read in conjunction with the Company's audited financial statements and related notes for the year ended December 31, 2008 and the unaudited interim financial statements for the period ended June 30, 2009. This MD&A is effective August 28 , 2009. Additional information relating to the Company can be found on the SEDAR website at www.sedar.com.

We have two reportable business segments with all activities located in the United States:

- **Crude oil and natural gas production segment** – the Company produces oil and gas from three Permian Basin crude oil fields located in eastern New Mexico. The fields were purchased in 2007 (Chaveroo Field and Milnesand Unit) and 2008 (Crossroads Unit) because they represent excellent candidates for enhanced oil recovery through CO_2 injection (See **Acquisitions of Enhanced Oil Recovery Capable Properties)** based on estimates of substantial remaining original-oil-in-place ("OOIP"). These fields currently represent production of approximately 320 barrels of oil per day (Bbl/d), currently with no proved reserves attributable to CO_2 recovery. The OOIP associated with these fields represents more than 300 million barrels, of which as much as 25% of OOIP could be recoverable through enhanced recovery methods by CO_2 injection. The Milnesand Unit CO_2 pilot project ("MSU Pilot") is the Company's first CO_2 pilot project, which commenced in March 2008, with CO_2 injection initiated in August 2008 (See **Strategy for Enhanced Recovery Projects in Crude Oil Fields** below).

- **Helium and CO_2 resource segment** – the exploration for and production of helium and carbon dioxide (CO_2) within the St. Johns field ("St. Johns Field"), a 250,174 acre resource property in Arizona/New Mexico discovered by the Company in 1994. The field is one of the largest known undeveloped natural CO_2 resources in the world, with approximately 15 Tcf of CO_2 and 26 Bcf of helium gas in place (See **Resource Estimates** below). The field is in the early stage of development, pending the construction of a pipeline required to transport CO_2 to the Permian Basin. Development drilling of the field, construction of a gathering system and a helium processing plant would commence after the point that pipeline financing is committed. The Company was not successful in securing a joint venture partner in a Project review process initiated in February 2009 and completed in June 2009. The Company is evaluating alternatives to the joint venture approach to the development and use of this segment. (See "**Further Development of St Johns Field"** and "Impairment of Property and Equipment" below).

The current economic environment has increased uncertainties affecting business strategies generally, with a worldwide recession, unpredictable commodity prices, volatile credit markets and limited access to capital. As a development stage enterprise, these uncertainties have affected our ability to meet our long-term strategies of developing our business segments primarily because of our reliance on equity capital in the absence of profitable operations. Without sufficient capital the success of our business plan will be difficult to achieve since both our business segments depend principally on commodity price thresholds sustainable over long-term periods in order to justify the capital investment that these projects demand, while they currently face competing petroleum investment strategies with capital requirements that may enjoy lower operating cost structures. With the contraction in the credit and equity markets, success in our helium and CO_2 segment is now more dependent on coupling this resource with a smaller pipeline to our own enhanced oil recovery projects, including the cash flows from our crude oil production, and limiting the use of CO_2 injection floods to our own oil properties and potentially to a smaller group of producers near to our existing properties. Establishing an alternative economic pipeline justification in this approach will entail additional pipeline path and cost analysis which will be evaluated in the third and fourth quarters of 2009. In addition, the Company is pursuing financing for the development of its oil properties through secondary recovery water floods which is necessary element preceding CO_2 injection. The Company's projects are inherently long-term and management will continue to take a long-term view as it considers, among other criteria, current and expected economic and operating alternatives.

Further Development of the St Johns Field

In 2007 and 2008, the Company raised and committed substantial resources to the exploration of the St. Johns field to establish its potential to produce helium and CO_2 in quantities sufficient to justify the cost of delivery to users of the products. In 2008, the Company completed sufficient exploration to broadly define the characteristics of the field that enabled third party engineering firms to provide estimates of the field's reserves and the estimated deliverability to allow the Company or its representatives to solicit long-term commitments from potential consumers. In addition, the Company executed an Memorandum of Understanding (MOU) agreement in March 2008 with Suncoast Energy, Inc. ("Suncoast"), a pipeline expert, to develop the scope and path of a pipeline and to secure financing of a pipeline suitable for the CO_2 market in the Permian Basin. Working together with third party engineering firms to design and estimate the costs to construct the gathering and processing systems for the field and with its knowledgeable pipeline experts, a project design and pipeline design was conceived and proposed in the summer of 2008. However, in connection with the changes in economic conditions in late 2008, it became apparent that the Company could not continue to develop the St Johns field solely from its own capital sources. After the credit market collapse following September 2008, financing a development project of the size and scope of the projected investment in St Johns field, as well as on financing the third party pipeline, became more difficult for a company with limited resources. It became clear that increased cost of capital requirements now prevail for such projects and the uncertainty of energy prices will affect rate of return requirements for prospective investments.

In October 2008, Suncoast advised the Company that they could not secure pipeline financing for the proved CO_2 reserves at St Johns without the Company engaging a co-venturer of sufficient financial resources to assure the field's development. To that end and in view of the continuing depression in credit markets and the reverberating effects on capital sources for a pipeline financing, the Company engaged Tristone Capital, an energy focused investment banking firm specializing in oil field transactions to pursue a Joint Venture transaction. Tristone Capital solicited and qualified confidential parties to present the engineering evaluation and planned development related to the helium and CO_2 reserves at St Johns field and the project development design to meet the CO_2 pipeline capacity scaled between a minimum 350 up to 500 mmcf per day to the Denver City, Texas area in the Permian basin. Tristone Capital organized the presentation and assembled the engineering data and presented the project parameters and objective on a confidential basis to a broad range of Permian Basin energy companies, and others, meeting the necessary financial resource qualifications and CO_2 demand requirements for the scope of the Project, as designed. The objective of the engagement was the securing a joint venture partner or the potential for joint venture opportunities with other industry participants for development of the Company's interests in the St. Johns Field.

Several parties signed confidentiality agreements and reviewed the data either in the physical or electronic data room, however, the Company did not receive any expressions of interest in pursuing a joint venture in St John's Field nor did it receive any offer for outright ownership of the property.

We believe the Tristone Capital engagement was not successful in securing a joint venture partner for the development of the St Johns Field, primarily for the following reasons:

- The scope of the project, estimating an investment of US$1.0 billion to US$1.6 billion over the project lifetime, was larger than prospects wanted to consider in this current market,
- Internal rates of return for competing investments were higher than could be demonstrated from the St Johns Field development based on the CO_2 as the primary revenue source,
- The financing of the pipeline was uncertain based on the capacity design, the length of the pipeline and the proved reserves that Suncoast required.

Although we are disappointed that a transaction was not successful, we remain committed to the view that the potential for use of this asset is ultimately valuable to the oil industry, including ourselves, as well as other potential uses, however, ultimately realizing value on the asset will continue to require that the Company finance the holding costs over a long-term period until pipeline financing is secured and a pipeline is constructed.. We believe we have reduced such future holding costs in the short-term period, absent any required drilling, to allow the Company to continue to develop alternatives to the project design concluded in 2008.

As a result of the conclusion of the Tristone Capital engagement in June and the difficulty of the efforts to secure pipeline financing, the Company has subsequently reviewed the recommendations and assumptions concerning pipeline capacity and the approach to developing its projects. Management is reviewing the feasibility of a smaller pipeline that would reduce the capital costs to deliver a smaller volume of CO2 for use in its own oil fields in Roosevelt, Chaves and Lea counties in New Mexico and possibly to a smaller group of potential CO_2 users in close proximity to these properties. The smaller project would couple the oil field interests with the CO_2 resource to combine investments that would be supported by the recovery of crude oil with a view of increasing rate of return, lowering capital costs and the lowering cost of capital through a comprehensive investment.

In addition, the Company is evaluating the water flood projects and reserve potential from water floods on the Milnesand Unit and the Chaveroo fields. Water floods are secondary recovery methods normally implemented on oil fields prior to the commencement of CO_2 injection. The Company's Milnesand Unit has had limited water injection and Chaveroo has had almost no comprehensive water injection. These properties have available water and other water sources to initiate comprehensive water injection. The Company has commissioned reserve studies from its independent reserves evaluator from water flood of these fields and expects initial results in September

Current Operating Activities

From an operating standpoint, the activities planned in 2009 for the operating and project phases for both our business segments have been curtailed to minimize cash outlays, and are focused principally in the oil field segment on activities that can generate additional free cash flow, in order to cover overhead more completely and facilitate our control and development of the St. John's Field. In addition, we have focused our operating activities to increasing cash flows from our oil and gas producing properties, including well re-activations and workovers that increase production and projects that reduce our lifting costs. Since September 2008, we have reduced our personnel and other general and administrative expenses by approximately US$2.0 million per year compared to

2008. Currently, we have 15 employees compared to 26 in September 2008 and may continue to reduce our headcount in the third quarter of 2009. We spent considerable effort in developing our operations base to meet the needs that our helium/CO_2 project would require once the CO_2 pipeline project was committed. As a result, through June 2009, our overhead allocation between the two segments was heavily weighted to the helium and CO_2 segment, which was necessary in this project's design phase and recent marketing phase until the Tristone Capital engagement was completed (discussed above). We have reduced the concentration of personnel in this area more significantly than in our oil and gas operations where we currently have revenues and opportunities for more immediate cash flow enhancement. In addition, we are currently focused on reducing short-term cash requirements from unitization of property interests in both segments and from certain equipment held for sale. In our oil field segment, until our recent increase in production we were reluctant to hedge our commodity prices due to our small production volumes, however, we are currently evaluating the current economics of such contracts in connection with development financing of our Crossroads Field re-activations and workovers.

In addition, the Company is evaluating the water flood projects and reserve potential from water floods on the Milnesand Unit and the Chaveroo fields. Water floods are secondary recovery methods normally implemented on oil fields prior to the commencement of CO_2 injection. The Company's Milnesand Unit has had limited water injection and Chaveroo has had little water injection. These properties have available water and other water sources to initiate comprehensive water injection. The Company has commissioned a reserve studies from its independent reserves evaluator from water flood of these two fields and expect those reports in September.

In addition and in light of the current market situation, we have endeavored to plan a flexible approach to 2009 investment and structured a limited capital expenditure program to adjust investments depending upon how economic circumstances change during the year. Currently, our planned capital expenditures program for 2009 has been reduced to US $2.0 million, pending improved prices for crude oil or mandatory expenditures, if any. We have development potential at the Crossroads Field and will attempt to re-activate or renter up to six wells in the third and fourth quarters of 2009, subject to financing and initial results.

For the remainder of 2009, management is focused on the activities necessary to prepare the development plans to increase production of its crude oil properties in New Mexico and continue efforts to establish a development plan and supporting economics for the St Johns Gas Unit field primarily for our own use, including:

- Increasing cash flow from our oil field properties through operating efficiencies and reducing costs and pursuing additional oilfield acquisitions consistent with immediate cash flow enhancement and the objectives for our existing oil field properties,
- Completing the final stages of the MSU Pilot Project and producing an independent evaluation of reserves attributable to CO_2 recovery,
- Securing final regulatory approvals, principally federal, for the St. Johns Gas Unit, the 170,000 acres comprising substantially all the state of Arizona leases of the St. Johns Field,
- Structuring joint crude oil flood projects with other producers employing CO_2 injection,
- Establishing an alternative pipeline economic justification to finance a more direct delivery of CO_2 to our crude oil properties.
- Combining oil field interests with other Permian basin producers in arrangements to secure pipeline financing and CO_2 delivery by combining oil field ventures to improve project returns.

While the current global financial circumstances may restrict our access to capital markets and create significant volatility in equity valuations, management believes its projects have the scope and potential that will justify long-term investment by consumers and producers of the resource interests we have assembled. The fundamentals of our St. Johns project will continue to be tailored to changing conditions of markets and competing transactions. Our project requires a long-life resource perspective and is complemented by the long-term productive potential for producing crude oil from our recent oil field acquisitions.

Helium and CO_2 Resource Segment – History and Business

In its history, the Company has explored for precious metals, diamonds and crude oil and natural gas in North America. In 1994, the Company discovered helium and carbon dioxide ("CO_2") while drilling for crude oil and natural gas on what later developed as the St. Johns Field located in eastern Arizona and western New Mexico. The Company currently owns a 100% working interest in leases covering approximately 251,000 gross acres and continuously manages its lease position to optimize its land position within St. Johns Field. From 1994 through 2006, the Company had been engaged principally in the business of exploration and appraisal of the St. Johns Field. Through June 30, 2009, we have expended approximately $99.7 million in acquiring, exploring and appraising the St. Johns Field, with over $33.4 million invested in the appraisal of the field during the twelve months of 2008. Prior to 2007, the Company had drilled seventeen exploratory and delineation wells. Prior activities had focused on periodic drilling to maintain its lease position, with production testing, well data evaluation, feasibility studies and resource evaluations limited by available capital. Though constrained, the results of these activities enhanced the view that the St. Johns Field contains significant gas in place.

During 2007, the Company began to grow its infrastructure necessary to support the extensive tasks required for the financing and development requirements of the St. Johns Field that had constituted its sole asset for over ten years, but with little movement towards its development to that point. In 2007 and 2008, increasing crude oil prices allowed us to present the St. Johns Field as an attractive investment alternative through a strategy that would source CO_2 from our own property for use in our own EOR projects in order to establish a potentially significant crude oil reserves base. This exploitation strategy made economic sense in 2007 and allowed us to raise the equity to fund additional evaluation projects needed for our helium and CO_2 source field and to purchase EOR properties in the Permian Basin suitable for CO_2 flooding projects. Even considering the fall in crude prices in late 2008, stranded oil in the Permian Basin represents a reasonable bargain compared to other exploration plays due to the recovery potential of OOIP in certain fields and formations as demonstrated by recent production histories of CO_2 floods in the basin. As a result, we began an active acquisition program in 2007 for oilfields with significant OOIP and with characteristics suitable for CO_2 injection. This strategy change was especially important to our success in raising net proceeds from equity offerings of $59.1 million during 2007 and an additional $32.5 million in 2008. In addition, our recent success in our Crossroads field from well re-activations has demonstrated additional primary production potential in this field with immediate impact to our cash flows.

In February 2009, we filed our proposed unitization agreement with the Arizona State Land Board for the unitization of 170,300 acres of State of Arizona leases (the "St. Johns Gas Unit"), of which we own leases representing 136,100 gross acres. The unitization of the property interests will allow the Company to maintain its leasehold position by production or by conducting development operations on any of the leases rather than by each separate lease. In the proposed Unit, assuming all leaseholders elect to participate in the Unit, the Company will hold a minimum working interest of approximately 80 % of the Unit with the balance currently held by the one other leaseholder, Hunt Oil

Corporation. The St. Johns Gas Unit Agreement would impose a minimum development plan on the Unit's participants over a five year period and will include a commitment to drill five wells in the 12 months following its approval. We have received approval for the St. Johns Gas Unit from the State of Arizona and the approval of the US Bureau of Land Management.

In January 2007, we received all approvals for the formation of the Cottonwood Canyon Unit Agreement in Catron County, New Mexico, part of the St. Johns Field. The Cottonwood Canyon unit covers an area of 89,734 acres. This unit agreement calls for the orderly development of the unit area over a five year period. Ridgeway Arizona Oil Corp, a wholly-owned subsidiary of the Company, is designated as the unit operator and is the only working interest participant in the Unit.

St. Johns Field - Drilling Activity

Decreases in oil prices in late 2008 and the resulting effect on the Company's ability to raise additional capital has caused the Company to severely restrict its projects for 2009 and curtail expenditures in order to conserve cash. No drilling activity for the St. Johns Field was scheduled in the first half of 2009 or is currently planned for the third quarter of 2009, except for drilling obligations. During 2008, we drilled 15 net wells to various stages of completion in the St. Johns Field. This is in addition to the 13 net wells we drilled to various stages of completion during 2007. This drilling program was initiated to provide additional data regarding field-wide reserves and deliverability and at the same time preserve the Company's dominant acreage position in the area. This drilling activity expanded our knowledge of the field significantly, which is crucial to the planning of full-field development. The program allowed us to accumulate additional data including well logs for production and reservoir modeling, assess alternative drilling and completion techniques, gather and evaluate bottom hole pressure data, perform pressure transient analysis and review wellbore design modeling alternatives. Program results have been very encouraging, yielding increasing well production estimates that allow more economic projections of future development costs. Previously, estimated production rates of 1.5 Mmcf/d per well were expected. Well design changes have resulted in actual production rates averaging 3.0 Mmcf/d, with a high of 6.5 Mmcf/d. Two lateral re-completions were also successfully drilled, one of which increased production of a well on the far edge of the St. Johns Field from 200 thousand cubic feet of gas per day ("Mcf/d") to 2.0 Mmcf/d, which opens up over 20% of the St. Johns Field to larger production volumes. We believe these wells represented the first horizontal wells drilled in Arizona. As a result, we began initial feasibility studies for several gathering system options which will mesh with reservoir deliverability to plan well spacing and development.

In June 2007, we announced the completion of testing of a newly discovered fractured basement zone in one of the wells being drilled. The well was tested continuously for a 30-day period and has consistently been producing CO_2 at rates of 245 Mmcf/d with no produced water. There was no decline in either flowing pressures or production rates during the testing. In addition, the helium content measured over this period is consistently in the range of 1.0% of total gas and appears to indicate that this well has discovered a new, high potential, helium pool. Further evaluation of this fractured basement zone will be conducted in future delineation wells in order to further understand the significance of this new pay zone. To date, we have drilled and evaluated 47 wells across the St. Johns Field. Individual wells have tested CO_2 at sustained rates as high as 6.5 Mmcf/d. Each well is approximately 2,500 ft deep and is capable of being drilled and completed within one week.

Subject to an appreciable improvement in the price of crude oil, if any, we do not anticipate additional drilling in the St. Johns Field except in connection with St. Johns Gas Unit obligations, discussed above upon final ratification of the Arizona Unit Agreement.

We are considering other technologies and ventures to use the resources available to the Company in the St Johns Field which could lead to the ultimate development of the field.

Resource Estimates

The following information has been extracted from, and is attributable to, the Helium and CO_2 Resource Evaluation report on the St. Johns Field addressed to the Company dated as of June 12, 2008, prepared by W.M. Cobb and Associates of Dallas, Texas, an independent firm of professional engineers (the "Cobb Report").

The 2008 Cobb Report, updating a 1999 report from the results of the Company's drilling and flow testing programs in 2007 and 2009, indicates that the St. Johns Field resource is potentially significantly larger than earlier estimates had suggested with potentially recoverable reserves increasing to eight Tcf of CO_2 and 33 Bcf of helium over a 40 year life. With the higher deliverability of in excess of 6.0 Mmcf/d achieved from the most recent wells drilled in 2008, the 20 year production outlook has increased to 6.6 Tcf of CO_2 and 26 Bcf of helium.

	CO_2			Helium		
Case	**Reserves In Place (tcf)**	**20 Year Recoverable (tcf)**	**40 Year Recoverable (tcf)**	**Reserves In Place (bcf)**	**20 Year Recoverable (bcf)**	**40 Year Recoverable (bcf)**
1999 Report	13.9	-	6.0	64.0	-	33.0
2008 Report --Relative Risk:						
Lower Risk	11.3	5.0	6.2	47.0	20.0	26.0
Higher Risk	13.4	5.9	7.4	56.0	24.0	30.0
Highest Risk	15.0	6.6	8.2	62.0	26.0	33.0

Proposed Third Party CO_2 Pipeline – St. Johns Field to the Permian Basin

The Company's current plan would utilize a third party owned pipeline to deliver CO_2 to the Permian Basin including a call on the product for injection into its own oil fields. Securing a third party owner to finance, construct and operate the pipeline is a significant objective for the Company that may determine the ultimate success of developing the St Johns field. The Company's CO_2 reserves would be committed to the pipeline under a life of reserves dedication agreement at the point financing of the pipeline is committed. Construction of the pipeline would require up to two years to complete.

In March 2008, we executed a Memorandum of Understanding ("MOU") for the development of the Company's pipeline project with privately held Suncoast. The MOU is subject to a number of conditions, among which included the Company's responsibility to deliver estimates of reserves from independent reservoir engineers (the "Reserve Report"). The Reserve Report was delivered in August 2008. Working together with third party engineering firms and experts we engaged to design and estimate the costs to construct the gathering and processing systems for the field and with its knowledgeable pipeline expert, a project design and pipeline design was conceived and proposed in the summer of 2008. The proposed pipeline was projected to run 350 miles from the St. Johns Field to the Permian Basin of New Mexico and West Texas; and initially transport 350 million cubic feet per day (Mmcf/d) of CO_2 for injection into depleted oil fields located within the Permian Basin, with an ultimate capacity of 500 million cubic feet per day (Mmcf/d). Suncoast is responsible for securing its financing for the pipeline project (the "Pipeline Project Financing"). Estimates of capital and operating costs for the pipeline are substantially dependent on the price of steel and energy, which would affect the transport tariff for CO_2 to the ultimate users. Since May 2009, the Company has reviewed the 2008 recommendations and assumptions concerning pipeline capacity and the approach to developing its projects. Management is reviewing the feasibility of a smaller pipeline that would reduce the capital costs to deliver a smaller than the original design capacity for the needs of it oil fields in Roosevelt, Chaves and Lea counties in New Mexico and possibly to a smaller group of potential CO_2 users near its properties. The view of a smaller project would couple the oil field interests with the CO_2 resource to propose investments that would be supported by the recovery of crude oil with a view of increasing rate of return, lowering capital costs and the lowering cost of capital through a comprehensive investment.

Pursuant to the MOU, SunCoast's obligations included arranging the necessary Pipeline Project Financing during an exclusive six-month period after delivery of the Reserve Report. As of the date of this report, SunCoast had not completed its obligations to provide the Pipeline Project Financing, however, discussions concerning an additional non-exclusive period, if any, and, taking into account the results of the Tristone Capital engagement (see above) related to securing a joint venture participant for the development of the St. Johns Field, have continued. The Company would expect to incur costs in connection with the MOU related to certain of SunCoast's reimbursable expenses in arranging the Pipeline Project Financing, however, would not be due if successful. In addition, SunCoast could receive additional compensation under the MOU in the amount of a fee of $250,000, although the Company does not believe SunCoast is currently entitled to the fee.

Crude Oil and Natural and Production Segment - History and Business

The Company entered this business segment through the purchase of two oil fields located in the Permian Basin in 2007. In September 2007, the Company opened an operations office in Midland Texas, operating under the name of EOR Operating Company and focused on establishing enhanced oil recovery projects on the newly purchased fields. See further discussion below under "***Acquisitions of Enhanced Oil Recovery Capable Properties***". In connection with one of our acquisitions, we have had recent success in identifying additional primary production to the extent that this field may represent substantially more primary reserves (See "***Strategy for Enhanced Recovery Projects in Crude Oil Field – Crossroads Unit Field Operations"*** *below).*

Establishing an operating platform in oil and gas operations in the Permian Basin in 2007 resulted in the Company's first operating activities generating a current revenue stream and permitted us to attract the skilled personnel that are necessary for the engineering, planning and project evaluation across both of our business segments. Although this decision opened a second front of capital commitments in the oil and gas business, this segment would allow us to use our very significant CO_2 resources to generate potentially significant crude oil reserves. On one of these properties acquired in 2007, the Company has initiated limited CO_2 injection on the MSU Pilot, a pilot project to evaluate these fields projected response to a full field CO_2 flood. These property acquisitions initially had limited production. Currently, except for the Crossroads field, the Chaveroo and Milnesand Unit fields are essentially resource assets with substantial project requirements necessary to establish secondary or enhanced recovery reserves, which the Company may not be able to finance. The Company is currently evaluating opportunities to establish water flood projects on the Milnesand Unit and the Chaveroo fields and expects results from initial studies in September 2009.

Acquisitions of Enhanced Oil Recovery Capable Properties

In February and May 2007, we announced the acquisition of two New Mexico oil fields that the US Department of Energy ("DOE") has identified as having considerable enhanced oil recovery ("EOR") potential. These acquisitions cover approximately 21,000 acres and have produced approximately 36 million barrels of oil to date, leading to only 14% recovery of the estimated original 275 million barrels of original oil in place. In June 2008 the Company completed the acquisition of its third property in the Permian Basin suitable for tertiary recovery by CO_2 injection for $4.5 million. This unit has produced approximately 22 million barrels of crude oil to date, yielding a 35% recovery of an estimated 125 million barrels of original oil in place. In addition, this latest acquisition is located proximal to our original acquisitions and will allow for tremendous synergies and cost savings once we begin to CO_2 flood these fields.

Effective July 1, 2008, the Company purchased a 100% working interest in a 1,900 acre New Mexico oil field for US $436,000. The property is contiguous to our existing Milnesand San Andres Unit and is a logical property expansion. The Company estimates that this property contains approximately 24 million barrels of original oil in place, only 10% of which is estimated to have been produced to date. The acquisition closed in October 2008. The Company capitalized the estimated asset retirement obligation of US $230,000 at the effective date based on the discounted estimated cash flows to retire and abandon the property.

As discussed above, in February and May 2007, June 2008 and again in October 2008, we announced the acquisition of three New Mexico oil fields that the DOE has identified as having considerable EOR potential. These acquisitions cover approximately 23,900 acres and have produced approximately 58 million barrels of oil to date, leading to only 15% recovery of the estimated original 400 million barrels of original oil in place. The Company's independent enhanced recovery consultants, Advanced Resources International ("ARI"), completed a proprietary review of these fields for the Company and, in reports dated January 3, 2007, March 19, 2007, and April 7, 2008, have estimated that these fields could recover an additional 75 million barrels of oil using state of the art CO_2 injection processes. These are categorized as "contingent resources" under NI51-101. ARI also estimates that these fields have the potential, once fully flooded, to reach enhanced recovery peak production rates of over 23,000 barrels of oil per day. In 2008, we initiated the MSU Pilot, a pilot CO_2 flood on a portion of the Milnesand Unit, acquired in 2007. The Company commenced injection of CO_2 in August 2008 following a six month water injection program and continued CO_2 injection until the end of July 2009. Water injection is continuing in the MSU Pilot. The incremental production response from the pilot is being evaluated for estimates of production that might be recoverable, if any, from a full-field water flood and CO_2 flood. Under NI51-101 "contingent resources" are those quantities of oil and gas estimated on a given date to be potentially recoverable from known accumulations but is currently not economic.

Strategy for Enhanced Recovery Projects in Crude Oil Fields

Long-term, the Company holds its three crude oil fields pending the establishment of full field CO_2 floods sometime in the future, which will depend ultimately on the price of crude oil and the operating costs required to produce these enhanced recovery projects economically. Management expects these projects will not commence until pipeline financing is committed (See ***Proposed Third Party CO_2 Pipeline – St. John's Field to the Permian Basin*** above). Until then, two of the Company's three oil and gas fields in eastern New Mexico are marginally economic at the current crude oil prices being received for sales.

Chaveroo Field Operations. The Company intends to consolidate its ownership of the Chaveroo field through further unitization of the unconsolidated property interests and produce the field on a limited basis as economics permit to preserve the non-productive acreage. The Chaveroo field, which is comprised of approximately 264 wells within multiple unconsolidated operating units and other discrete operating leases, has approximately 36 wells capable of producing under current economics. For the six months ended June 30, 2009, all of the wells capable of production in this field were not uniformly economic at the field posted prices for New Mexico sour crude. Leases in the Chaveroo field are held by a combination of producing certain wells, payment of delay rentals or reactivation of non-producing wells, the costs of which may or may not prove to be economic under this current operating strategy.

Milnesand Unit Field Operations. The Company's Milnesand Unit is comprised of approximately 92 wells, of which 31 are capable of production. Although certain wells in the field may be economic at the current pricing for New Mexico sour crude, the Company is conducting a CO_2 pilot injection project within a portion of these producing wells, which results in a much higher operating cost than current prices would justify continuing to produce. Since inception of this pilot in March 2008, the Company has capitalized the incremental project costs in excess of lifting costs, of the MSU Pilot under full cost accounting principles as major development project costs, pending the results of the pilot. This evaluation period usually requires a period of as much as 12 to 18 months once CO_2 injection is commenced to determine the predictable production response, if any. The Company commenced CO_2 injection in August 2008. The Company expects to complete the final stages of the MSU Pilot during the remainder of 2009, primarily through discontinuing the injection of CO_2, which occurred in early August 2009, but continuing water injection through the remainder of the current year. The Company has undertaken to have its independent reserves evaluator produce a reserve report on the recoverable CO_2 reserves by early in the fourth quarter of 2009. The classification such reserves, if any, as proved reserves may depend on the presence of a CO_2 pipeline or CO_2 gas contract.

Currently, the Company produces the above two fields managing the combined objectives of (i) optimizing net cash flow or out flow (ii) maintenance and retention of multiple lease positions through production, however limited, and (iii) consolidating and controlling these property interests for their long-term potential through enhanced recovery techniques. For the six months ended June 30, 2009, we reduced our gross lifting costs (excluding severance taxes) in the two fields to an average of approximately US $24.16 per Boe compared to US $42.57 per Boe averaged for all of 2008.

Crossroads Unit Field Operations. The third New Mexico field, the Crossroads Unit, which comprised approximately 55% of our second quarter gross oil production (currently comprises approximately 67%), is economic at current prices and has current lifting costs of approximately US $6.23 per Boe. As discussed above, we have re-entered and re-activated one additional well each quarter in the Crossroads Unit in 2009 and as a result have increased production by 65 Boe's per day for the first half of 2009. On July 31, a fourth well began producing an average of an additional 120 Boes per day. We have identified four additional wells which we intend to attempt to re-activate in this field, subject to financing the capital costs related to these workovers. For the six months ended June 30, 2009, we reduced our gross lifting costs (excluding severance taxes) in this field to an average of approximately US $6.23 per Boe compared to US $12.40 per Boe averaged for all of 2008.

The combined contribution of net revenue available from these three properties to cover other costs is currently projected for the remainder of 2009 at current prices and current production levels is projected to be approximately $530,000 per month, net to the Company's interest, before any capital outlays Capital expenditures in the oil and gas segment during 2008 included $6.1 million to acquire additional property interests in New Mexico with EOR potential, US $7.4 million for the MSU Pilot, $4.4 million for field facilities and well work preparatory to future EOR projects in the three oil fields discussed above. Capitalized costs related to proved reserves are subject to periodic ceiling tests in connection with the full-cost method of accounting for oil and gas properties. The Company periodically evaluates the recoverability of the capitalized costs associated with unevaluated oil and gas interests related to all its fields based on both internal and third party studies and evaluations of estimates of potential recovery of its prospective interests.

Liquidity and Capital Resources

At June 30, 2009, we had cash of $2.1 million and working capital in excess of $3.3 million, a decrease of $3.1 million and $3.1 million, respectively since December 31, 2008. The capital intensive nature of the Company's activities may create a working capital deficiency position during periods with high levels of capital investment. Due to the development stage of its businesses, the Company has relied on equity placements to fund capital investment, and cash flow from its oil production to fund its cash requirements. On June 3, 2009, the Company closed a non-brokered private placement of 4,333,333 units priced at $0.45 each and consisted of one common share and one-half of one non-transferable common share purchase warrant. Each whole share purchase warrant entitles the holder to purchase an additional common share at $0.60 until June 30, 2010. Gross proceeds totaled $1.9 million and the Company incurred offering costs of $0.2 million thereby realizing net proceeds of $1.7 million. The Company does not currently have credit facilities to finance its projects, however, may seek to establish initial credit facilities based on its proved crude oil reserves to fund activities designed to increase current production. Although crude oil price increases since March 2009 have increased our net revenue from production, the wide swings in oil prices over the past two years and the continuing uncertainties in credit and equity markets will limit our ability to secure additional sources of capital during a critical time of developing our businesses and projects. As a result, the Company has suspended discretionary operating activities and is planning on a sustained period of reducing such activities until credit and equity markets improve (See **Financial Strategy in Current Economic Environment** above). Notwithstanding these actions, the Company may be unable to fund its projects or operations or achieve its objectives without additional capital. We are seeking intermediate term secured bank financing to finance our workovers and well re-activations at the Crossroads Unit field, as discussed above. We will continue to require additional funds to execute the Company's business plan. Our stock price has decreased substantially compared to the equity placements we have issued during the last two years. Currently, our source and access to capital is considered limited and there is no assurance that we will be successful in raising additional funds.

Since September 2008, we have taken steps to reduce all costs amid continuing economic challenges. These measures include changes to employee headcount, a hiring freeze and reduced compensation levels. We will take additional cost reduction steps to minimize our cash requirements if such actions are warranted. Since July 2009, we have taken additional actions which are expected to lead to reductions in operating costs, and general and administrative expenses of approximately US$2.3 million compared to the spending levels incurred for all of 2008 or a decrease of approximately 45% with the current general and administrative expense projected to decrease by 29% for the year to year annual comparison. Our general and administrative costs, including field offices (a component of lease operating expenses) decreased US $0.2 million (or 17%) and US $0.3 million (or 24%) for the three months ended June 30, 2009 compared to the three months ended March 31, 2008 and December 31, 2008, respectively. The uncertainty of prices for crude oil, the fall in the price of the Company's common stock and the current uncertain prospects for any significant near-term improvement in equity and debt markets necessitates the changes given the Company's limited resources.

St. Johns Field Capital Budgets for 2008 and 2009

Our capital budget for all of the St. Johns Field originally totaled US $1.4 million for 2009, however, we incurred US $ 1.8 million for the six months ended June 30, 2009. These cost were principally related to the costs of the statutory unitization of the St. Johns Gas Unit, representing the field's leases in Arizona, which we received approval of the State Land Office in April; continuing engineering studies and pipeline investigation, the cost of the Tristone Capital engagement, minimal field work, and capitalized delay rentals.

In early 2008, we determined that in order to deliver an engineering report of the potential productive capacity of the field that drilling and flow testing of 10 wells and testing at least 20 gas horizons would be required. Initially, we planned to spend approximately US $12.9 million for 2008. We drilled 15 wells and re-entered 21 wells during 2008 and incurred approximately US $32.6 million in connection with this 2008 drilling program. Increased costs of drilling and services, drilling and re-entering more wells than we initially budgeted and the difficulty of completion techniques required for helium/CO_2 wells significantly increased our drilling costs beyond our initial budgets. This field is currently non-producing, pending financing and construction of a CO_2 pipeline, additional field development and construction of a helium processing facility. At the present, there are no plans for these projects to commence in 2009 unless the third party pipeline financing is committed (See **Proposed Third Party CO_2 Pipeline – St. Johns Field to the Permian Basin** above).

Oil Fields Capital Budget and CO_2 Pilot Project Budget for 2008 and 2009

These fields are currently producing approximately 310 gross barrels of oil per day from 63 producing wells, of which the Company has in excess of a 75% net revenue interest.

Our capital budget for all EOR projects totals US $1.6 million for 2009, of which we incurred US $1.3 million for the first six months of 2009, primarily related to workovers and capitalized pilot project costs. Expenditures for 2009 are focused on the continuation of the MSU Pilot through water injection only, developing production enhancement operations where feasible and regulatory maintenance, including reactivations or field maintenance. In addition, we intend to continue to pursue oil field property acquisitions that provide reserve development potential and additional cash flow to sustain the overhead costs required to maintain the projects we have undertaken.

Comparatively, we budgeted US $8.9 million for capital expenditures for 2008 in our oil and gas segment, excluding any property acquisitions (See **Acquisitions of Enhanced Oil Recovery Capable Properties** above). For 2008 we incurred US $5.0 million related to the acquisition of Crossroads Unit, the Milnesand Unit Expansion and other leases in the Chaveroo field. We incurred US $0.9 million for the six months ended June 30, 2009 and US $7.4 million for the year ended December 31, 2008 related to the MSU Pilot, principally involved with the cost of CO_2, well work and facilities expenditures.

Equity Placements

The impact on liquidity from the equity placements has been significant in allowing the evaluation of the helium and CO_2 resources in St. Johns Field, as well as the acquisition of prospective EOR assets in eastern New Mexico. Although expenditures are uncommitted, activities in St. Johns Field will continue, although not at the high levels incurred during 2008

Since 2006, we have completed ten offerings of equity securities raising total gross proceeds of $99.5 million, including the exercise of warrants, agency options and stock options of $12.6 million. In June 2009, we completed a private placement of common shares and warrants for net proceeds of $1.7 million. In 2007, we completed five equity placements that represented gross proceeds of $62.4 million and was comprised of 54.9 million common shares and 35.9 million warrants whose expiration is from one to two years of their issue date. Each of the offerings included warrants and/or agency options to acquire additional shares of the Company's common stock which would result in additional equity funds, should they be exercised prior to their expiration.

The following summarizes the equity placements since 2008:

Issue Date	Number of Units	Issue Price	Gross Proceeds
June 27, 2008	2,438,500	1.24	$ 3,023,740
June 30, 2008	22,975,681	1.24	28,489,844
July 16, 2008	1,655,000	1.24	2,052,200
July 31, 2008	1,290,000	1.24	1,599,600
June 2, 2009	4,333,333	0.45	1,950,000
Total	32,692,514		$ 37,115,384

i. On June 23, 2008, we announced a brokered private placement that closed in three tranches with the placement of 5,383,500 Units. The units were priced at $1.24 each and consisted of one Common Share and one-half of one non-transferable common share purchase warrant. Each whole share purchase warrant entitles the holder to purchase an additional common share at $1.80 until two years from each of the respective closing dates. Gross proceeds totaled $6.7 million. The Company incurred offering costs of $0.5 million, thereby realizing net proceeds of $6.2 million. We allocated the fair value of the net proceeds received upon the sale of the units between the underlying common shares and the common share purchase warrants. The common share purchase warrants' fair value was determined to be $1.2 million. The Company also issued to the Agent an option to acquire 376,845 additional units. The options expire in June and July of 2010. The Company assigned $0.2 million as the fair value of this option.

ii. On June 23, 2008, we also announced a non-brokered private placement that ultimately closed with the placement of 22,975,681 Units. The units were priced at $1.24 each and consisted of one Common Share and one-half of one non-transferable common share purchase warrant. Each whole share purchase warrant entitles the holder to purchase an additional common share at $1.80 and expire on June 30, 2010. Gross proceeds were $28.4 million. The Company incurred offering costs of $2.0 million, thereby realizing net proceeds of $26.4 million. We allocated the fair value of the net proceeds received upon the sale of the units between the underlying common shares and the common share purchase warrants. The common share purchase warrants' fair value was determined to be $6.2 million.

iii. On June 16, 2009, we announced a non-brokered private placement that closed with the placement of 4,333,333 Units. The units were priced at $0.45 each and consisted of one common Share and one-half of one non-transferable common share purchase warrant. Each whole share purchase warrant entitles the holder to purchase an additional common share at $0.60 and expires on June 3, 2010. Gross proceeds were $1.9 million. The Company incurred offering costs of $0.2 million, thereby realizing net proceeds of $1.7 million. We allocated the fair value of the net proceeds received upon the sale of the units between the underlying common shares and the common share purchase warrants. The common share purchase warrants' fair value was determined to be $0.1 million.

The following table depicts those warrants remaining outstanding at June 30, 2009:

Issue Date	Number of Warrants [(1)]		Exercise Price		Expiration Date
June 28, 2007	1,208,655	(5)	$	1.80	June 30, 2010
July 4, 2007	3,505,371	(5)	$	1.80	June 30, 2010
July 9, 2007	1,426,600	(5)	$	1.80	June 30, 2010
July 23, 2007	6,395,500	(5)	$	1.80	June 30, 2010
July 27, 2007	1,063,000	(5)	$	1.80	June 30, 2010
October 10, 2007	4,642,800		$	2.50	October 10, 2009
June 27, 2008	1,219,250	(3)	$	1.80	June 27, 2010
June 30, 2008	11,487,842	(3)	$	1.80	June 3, 2010
July 16, 2008	827,500	(3)	$	1.80	July 16, 2010
July 31, 2008	645,000	(3)	$	1.80	July 31, 2010
June 3, 2009	2,000,000	(4)	$	0.60	June 30, 2010
	34,421,518				

(1) The warrant numbers presented represent the number of whole warrants outstanding for each grant.

(2) These Warrants were issued in connection with the Company's brokered private placement announced on June 28, 2007.

(3) These Warrants were issued in connection with the Company's brokered private placement announced on June 23, 2008.

(4) These Warrants were issued in connection with the Company's brokered private placement announced on June 16, 2009.

(5) These warrants were to expire in June and July, 2009, but were extended until June 30, 2010 announced on June 16, 2009.

The table below details outstanding agency options as of August 28, 2009:

Issue Date	Number of Agency Options		Exercise Price		Expiration Date
July 9, 2007	243,920	(1)	$	1.24	July 9, 2009
July 23, 2007	1,205,700	(1)	$	1.24	July 23, 2009
July 27, 2007	212,600	(1)	$	1.24	July 27, 2009
October 10, 2007	742,848	(2)	$	1.80	October 10, 2009
June 27, 2008	170,695	(3)	$	1.80	June 27, 2010
July 16, 2008	115,850	(3)	$	1.80	July 16, 2010
July 31, 2008	90,300	(3)	$	1.80	July 31, 2010
	2,781,913				

(1) These Agency Options were issued in connection with the Company's brokered private placement announced on June 28, 2007, and entitle the holder to acquire one Unit for $1.24. Each Unit entitles the holder to one share of Common Stock and a Warrant to purchase 1/2 share of Common Stock for $1.80.
(2) These Agency Options were issued in connection with the Company's brokered private placement which closed on October 10, 2007, and entitle the holder to acquire one Unit for $1.80. Each Unit entitles the holder to one share of Common Stock and a Warrant to purchase 1/2 share of Common Stock for $2.50.
(3) These Agency Options were issued in connection with the Company's brokered private placement which closed on June 27, July 16, and July 31, 2008 and entitle the holder to acquire one Unit for $1.80. Each Unit entitles the holder to one share of Common Stock and a Warrant to purchase 1/2 share of Common Stock for $1.80.

Results of Operations

A factor influencing the Company’s results for all periods is the continuing fluctuation of the Canadian dollar relative to the United States dollar. Virtually all of the Company’s operating expenses and capital expenditures are paid in United States dollars while virtually all historical fundings have been in Canadian dollars and the Company’s reporting currency is the Canadian dollar. Although the Canadian dollar gradually strengthened over the past three years, it weakened against the US dollar during the first three months of 2009. For the six months ended June 30, 2009, the Company recorded a foreign currency translation loss of $77,000 compared to a gain of $40,000 for the comparable period in 2008.

Summary Unaudited Consolidated Statements of Operations

Unaudited	Three Months ended June 30,		Six months ended June 30,	
	2009	2008	2009	2008
Revenues				
Oil and gas sales, net of royalties	1,030	1,180	1,633	1,777
Interest and other	2	181	13	474
	1,032	1,361	1,646	2,251
Expenses				
Lease operating expense	583	603	1,340	1,811
General and administrative	1,193	1,126	2,403	2,238
Accretion of asset retirement obligation	105	80	213	156
Depreciation and depletion	443	227	834	255
Foreign currency translation (gain) loss	154	103	77	(40)
Stock-based compensation	279	908	637	3,209
Interest and other, net	-	16	-	15
	2,757	3,063	5,504	7,644
Loss for the year before income taxes	(1,725)	(1,702)	(3,858)	(5,393)
Income taxes	-	-	-	-
Loss and comprehensive loss for the year	(1,725)	(1,702)	(3,858)	(5,393)

June 30, 2009 Compared to June 30, 2008

The Company incurred a net loss of $1.7 million for both the three months ended June 30, 2009 and 2008. For the six months ended June 30, 2009, the net loss was $5.5 million compared to $5.4 million, principally related to a decrease in stock based compensation expense of $2.5 million and lease operating expenses of $0.5 million offset by increased depletion expense of $0.5 million and a decrease in oil and gas revenue of $0.1 million. The translation rate of the US dollar to Canadian dollar (the average Canadian dollar equivalent rate to convert current period US dollars) for revenue and expenses for the income statement periods presented were: $1.20 and $1.00 for the six month periods ended June 30, 2009 and 2008, respectively. There were significant changes in the components of revenue and expense of the current period compared to the prior period including a 98% increase in net oil and gas Boe's sold, a 59% decrease in average net crude oil prices, increases in field, operations and accounting personnel and the increased number of oil fields and projects. Oil and gas sales were essentially the same, however, increased production and barrels sold was offset by decreased prices compared to the prior period. Oil sales were generated from three fields in 2009 compared to two fields owned and operated in 2008. Increases in non-cash expenses of accretion, depletion and depreciation related to the increased number of operated oil and gas fields and increased oil production. Increased general and administrative expenses ($0.1 million) principally related to translation rates between the period as actual US dollar expenses actually decreased by US $0.2 million and offset by increased field office personnel (affecting lease operating and field expense) relates to decreases in the number of employees. Headcount had increased beginning in the fourth quarter of 2007 and was principally associated with the purchase of three oil fields. Our total headcount increased from an average of 15 employees in the first quarter of 2008, to 25 employees in the fourth quarter of 2008 and decreased to an average of 19 employees at the end of June 2009 as a result of reductions related to the changed economic conditions. Currently, we have 15 employees compared to 26 in September 2008 and we are continuing to reduce our headcount in the third quarter of 2009.

Operating Netbacks

(In US Dollars)		Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Oil & Gas Sales Volumes					
Oil equivalent	*Boe's*	17,841	10,818	37,299	19,936
Average prices [1]					
Oil equivalent	*$/Boe*	$ 54.65	$ 119.40	$ 45.16	$ 103.93
Less:					
Royalties, net [4]	*$/Boe*	$ (9.65)	$ (24.47)	$ (8.37)	$ (20.51)
Severance taxes	*$/Boe*	$ (4.48)	$ (10.83)	$ (3.70)	$ (9.02)
Operating expenses	*$/Boe*	$ (15.11)	$ (57.61)	$ (15.22)	$ (49.97)
Operating Netback [2]	*US$ / Boe*	$ 25.41	$ 26.49	$ 17.88	$ 24.42
Operating Netback by Field					
Crossroads Field [3]	*US$ / Boe*	$ 35.18	$ 50.26	$ 28.93	$ 50.26
Milnesand Unit	*US$ / Boe*	$ 19.92	$ 36.01	$ 10.71	$ 44.06
Chaveroo Field	*US$ / Boe*	$ 0.67	$ 31.93	$ 0.37	$ 13.41

[1] Average prices are after deduction of transportation costs and do not include realized gains and losses on financial instruments.

[2] Operating netback equals crude oil and natural gas sales less royalties, operating costs and transportation costs calculated on a Boe basis. Operating netback and funds from operations netback do not have a standardized measure prescribed by Canadian Generally Accepted Accounting Principles and therefore may not be comparable with the calculations of similar measures for other companies.

[3] Acquired effective May 1, 2008.

[4] Net of related severance taxes.

Oil and gas segment financial results are significantly influenced by fluctuations in commodity prices, which include price differentials related to the quality of crude oil and transportation charges, and the U.S./Canadian dollar exchange rate. Oil and gas sales for the quarters ended June 30, 2009 and 2008 were $1.2 million and $1.0 million, respectively, although production increased 65% to 17,841 Boe's (from three oil fields) compared to 10,818 Boe's (from two oil fields), respectively. Oil prices fluctuated dramatically for the periods reported for June 30, 2009 and 2008, with second quarter prices received of US$ 54.65 per Boe compared to US$119.40 per Boe for the second quarter of 2008.

As indicated, lease operating expenses decreased very slightly in absolute value for the quarter to quarter comparison and by $0.5 million for the six months ended June 30, 2009, however, decreased more significantly in per unit metrics by decreasing from US$57.11 per Boe in second quarter 2008 to US$15.11 incurred for the second quarter of 2009, principally due to the acquisition of the Crossroads Unit oil field which operates at substantially lower lifting costs per Boe and due to the decrease in maintenance activities in the Chaveroo and Milnesand Unit field in 2009 compared to 2008. The table above summarizes the Operating Netback for the comparable periods in US Dollars in the aggregate and by field for the periods ended June 30, 2009 and 2008. Lease operating expenses in the Crossroads Unit field are substantially lower than the other two fields at approximately US$6.23 per Boe for the six months ended June 30, 2009. Lease operating expense per Boe for the Milnesand Unit field and the Chaveroo field were US $21.78 and US$28.19 for the six months ended June 30, 2009, respectively compared to US $34.10 and US $65.34 for the six months ended June 30, 2008, respectively. Significant site maintenance expenses and unsuccessful well re-activations in the Chaveroo field in 2008 due to the age and condition of this field disproportionately contributed to the high lease operating expense in 2008. This field is characterized by very low per well production rates compared to the Company's other fields. The Chaveroo will continue to be marginally uneconomic and incur negative netbacks due to the substantial costs of site maintenance and deteriorated well bore conditions until either secondary recovery projects or enhanced recovery projects are initiated. The field, however, holds leases by production covering approximately 21,000 gross acres with significant potential for secondary and/or enhanced oil recovery. For both three month periods ended in March 2009 and 2008, the Company's netback was negative at US $7.57 and US $87.22, respectively. The negative netback in the first quarter of 2009 was attributed to the fixed costs of field office personnel and related office costs coupled with low crude prices.

The Company purchased its oil and gas properties with the intent to conduct tertiary recovery operations in these reservoirs that have already produced significant amounts of oil over many years; however, in accordance with the rules for recording proved reserves associated with enhanced recovery techniques, such as CO_2 injection, proved reserves cannot be recognized until there is a production response to the injected CO_2 or unless the field is analogous to an existing CO_2 flood. During this evaluation period we have capitalized all costs attributable to the fields as CO_2 major development project costs, except lifting costs attributable to production. Commencing with the initiation of the MSU Pilot in March 2008, we have capitalized US$8.7 million related to major development project costs, including production facilities, monitoring and measurement equipment and well work for the producing and injection wells in the pilot group, and the costs of enhanced recovery production equipment. These capitalized development costs are being carried in unevaluated major development project costs within our full-cost pool. After confirming a production response to the CO_2 injections (i.e. the production stage), injection costs will be expensed as incurred and any previously deferred project development costs will become subject to depletion upon recognition of proved tertiary reserves. For 2009 we capitalized $1.1 million of these expenditures related to all tertiary recovery projects. Prior to the initiation of our CO_2 development projects, lease operating expenses in 2007 and early 2008 associated with these properties, which are marginally productive fields, included significant remedial costs associated with lease maintenance activities, which were expensed.

Gross general and administrative expenses increased $0.1 million in the second quarter of 2009 as compared to the same period in 2008. General and administrative expenses denominated in US dollars actually decreased $0.2 million or 17% in the second quarter of 2009 compared to the comparable period of 2008 except for the increase in the rate of exchange for the Canadian dollar which increased from 1.003 to 1.245 per US dollar. This decrease was related to reduction in personnel and expenses implemented in the fourth quarter of 2008 as a result of the changes in markets and economic conditions. Through June 2009, our personnel concentration between the two segments was more heavily weighted to the helium and CO_2 segment, which was necessary in this project's design phase and recent marketing phase until the Tristone Capital engagement was completed (discussed above). We have reduced the concentration of personnel in this area more significantly than in our oil and gas operations where we currently have revenues and opportunities for more immediate cash flow enhancement. A decrease in stock based compensation related primarily to significantly decreased option pricing which affected the fair value expense computation for the grants. We anticipate continuing to use equity based compensation to attract and retain highly skilled employees and thus expect to continue to incur such costs in the future.

Management expects operating losses will continue during the development stage of the St. Johns Field and initiation of EOR activities in its three oil fields and will also depend on crude oil prices received for its production. Profitability may not occur until the St. Johns Field is further developed and helium and/or CO_2 are flowing to markets and the Company has expanded its EOR activities.

Summary of Quarterly Information:

In thousands, except per share amounts:

	2009	
	Second	First
Revenues	$ 1,030	$ 603
Loss	$ (80,341)	$ (2,133)
Loss per common share	$ (0.56)	$ (0.02)
Loss per fully diluted common share	$ (0.56)	$ (0.02)
Net loss	$ (80,341)	$ (2,133)
Net loss per common share	$ (0.56)	$ (0.02)
Net loss per fully diluted common share	$ (0.56)	$ (0.02)

	2008			
	Fourth	Third	Second	First
Revenues	$ 715	$ 1,988	$ 1,360	$ 890
Loss	$ (2,020)	$ (2,718)	$ (1,702)	$ (3,690)
Loss per common share	$ (0.02)	$ (0.02)	$ (0.03)	$ (0.03)
Loss per fully diluted common share	$ (0.02)	$ (0.02)	$ (0.03)	$ (0.03)
Net loss	$ (2,020)	$ (2,718)	$ (1,702)	$ (3,690)
Net loss per common share	$ (0.02)	$ (0.02)	$ (0.03)	$ (0.03)
Net loss per fully diluted common share	$ (0.02)	$ (0.02)	$ (0.03)	$ (0.03)

Disclosure Controls and Procedures and Internal Control Over Financial Reporting

As a TSX-Venture issuer, the Company's officers are not required to certify the design and evaluation of operating effectiveness of the Company's disclosure controls and procedures ("DC&P) or its internal controls over financial reporting ("ICFR"). The Company maintains DC&P designed to ensure that information required to be disclosed in reports filed or submitted is accumulated and communicated to management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In addition, the Chief Executive Officer and the Chief Financial Officer have designed controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Due to its size, the scope of its current operations and its limited liquidity and capital resources, there are inherent limitations on the Company's ability to design and implement on a cost effective basis the DC&P and ICFR procedures, the effect of which may result in additional risks related to the quality, reliability, transparency and timeliness of its interim filings and other reports. There have been no changes in ICFR during the period ended June 30, 2009.

Off-Balance Sheet Arrangements

The Company does not have any special purpose entities nor is it party to any arrangements that would be excluded from the balance sheet.

Related Party Transactions

In August 2007, the Company advanced $0.4 million to Forster, of which two independent directors of the Company are shareholders of Forster, to purchase a drilling rig and related drilling equipment. In connection with this rig purchase, Forster executed a 10% secured note due December 31, 2007, which was paid in full January 3, 2008, including accrued interest.

On November 21, 2007, the Company advanced Forster US $0.2 million to fund a security deposit on a drilling rig and subsequently advanced an additional US $1.5 million on December 3, 2007, to allow Forster to complete its acquisition of the drilling rig and related equipment. In connection with these transactions, Forster executed a 10% secured note payable to a subsidiary of the Company in the amount of US $1.7 million effective December 3, 2007, due March 27, 2008. Effective March 27, 2008, the Company extended the term of the secured note to June 27, 2008, and increased the rate of interest to 12% with interest payable monthly. On November 14, 2008 Forster assigned the rig and related equipment to the Company. The rig and equipment is classified as a current asset of equipment held for sale.

In January 2008, certain holders of the Company's $1.00 common stock purchase warrants with a scheduled expiration date of January 19, 2008, exercised the warrants prior to their expiration in exchange for promissory notes issued by the individuals (the "Notes"). The Notes aggregating $2,074,000 were due in full on July 19, 2009, with interest at 8.5% per annum. The indebtedness was made with full recourse to the individuals and were collateralized by all the shares purchased. The shares purchased were delivered to the Company under arrangements which required the sale of the shares during the period from July 19, 2008 through July 19, 2009, until the principal and interest were repaid. There were no sales of the common shares pledged to the Notes and no collections had been received. In addition, the underlying market price of the Company's Common Shares had declined to $0.43 per share. In November 2008, the Company agreed to cancel the Notes in exchange for surrender of the shares pledged as security for the loans and 2,074,000 common shares were cancelled. These transactions were accounted for as a deduction from shareholders equity, interest income be recorded as a contributed capital transaction when received, and the shares excluded from the loss per share computation in accordance with Canadian generally accepted accounting principles. Also, the shares securing the loans were required to be treated as stock options, including the recording of stock-based compensation expense of $1,120,000 in 2008. Two officers and one director participated in the share purchase loans aggregating $440,128 in connection with warrants exercised prior to their expiration in January. These related parties returned a total of 440,128 shares to the Company, which were cancelled in December 2008.

Critical Accounting Estimates

Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. Capitalized costs relating to the exploration and development of oil and gas reserves, along with estimated future capital expenditures required in order to develop proved reserves, are depleted and depreciated on a unit-of-production basis using estimated proved reserves. The carrying value of property, plant and equipment is reviewed annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Liability recognition for asset retirement obligations associated with oil and gas well sites and facilities are determined using estimated costs discounted based on the estimated life of the asset. These capitalized costs are amortized on a unit-of-production basis, consistent with depletion and depreciation. Over time, the liability is accreted up to the actual expected cash outlay to perform the abandonment and reclamation.

In order to recognize stock based compensation expense, the Company estimates the fair value of stock options granted using assumptions related to interest rates, expected life of the option, volatility of the underlying security and expected dividend yields. These assumptions may vary over time. The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded on the Company's financial statements.

Impairment of Property and Equipment

The carrying value of resource properties, including the St. Johns Gas field resource, are subject to impairment based on periodic assessments by management with regard to the sufficiency of estimated future cash flows or estimates of the fair value of the resource compared to the accumulated capitalized costs of the resource properties. Such assessments and conclusions may be affected by, among others, a decrease in market prices, adverse changes in economic conditions, unfavorable changes in project economics, or the difficulty in establishing an efficient distribution mechanism, all of which may be subject to significant uncertainty. The Company has assessed its resource properties as of the most recent balance sheet date and determined that its capitalized costs continue to be recoverable, however, that assessment may change if the Company is not able to either justify and/or finance a pipeline from the resource properties to its oil and gas properties or otherwise secure an economic use for the CO_2 in the field. Impairment is indicated if the carrying amount of the resource property is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the property and equipment is charged to earnings. The assessment of impairment is dependent on estimates of future cash flows, reserves, production rates, prices, future costs and other relevant assumptions.

Asset Retirement Obligations

The Company is required to provide for future removal and restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. The fair value of the liability for the Company's asset retirement obligations is recorded in the period in which it is expected to be incurred, discounted to its present value using the Company's risk-adjusted interest rate and expected inflation rate. The offset to the liability is recorded in the carrying amount of property and equipment. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

Stock-based compensation

In order to recognize stock-based compensation expense, the Company estimates the fair value of stock options granted using assumptions related to interest rates, expected life of the option, volatility of the underlying security and expected dividend yields. These assumptions may vary over time.

Changes in Accounting Policies and Practices

Effective January 1, 2009, the Company has adopted a new Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3064, Goodwill and Intangible Assets which provides guidance on the recognition, measurement, presentation and disclosure for goodwill and intangible assets. The adoption of this standard requires retroactive application to prior period financial statements and does not have an impact on the Company's financial statements.

Future Changes in Accounting Policies

In February 2008, the CICA's Accounting Standards Board confirmed that International Financial Reporting Standards ("IFRS") will replace Canadian GAAP in 2011 for profit oriented Canadian publicly accountable enterprises. The Company will be required to report its results in interim and annual financial statements in accordance with IFRS beginning in 2011. The Company is developing a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information.

Non-GAAP Financial Measurements

This document contains the term "netback", which does not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures by other companies. Netbacks are used by the Company as key measures of performance and is not intended to represent operating profit nor should they be viewed as an alternative to cash flow provided by operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. Netbacks are determined by deducting royalties, production expenses and transportation and selling expenses from oil and gas sales revenue.

Other Measurements

All dollar amounts are referenced in Canadian dollars, except when noted otherwise. Where amounts are expressed on a Boe basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel. The term boe may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Potential Risks and Uncertainties

The resource industry is highly competitive and, in addition, exposes the Company to a number of risks. Resource exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. It is also highly capital intensive and the ability to complete a development project may be dependent on the Company's ability to raise additional capital. In certain cases, this may be achieved only through joint ventures or other relationships, which would reduce the Company's ownership interest in the project. There is no assurance that development operations will prove successful.

In addition to the risks and uncertainties identified above, this Management's Discussion and Analysis contains several forward-looking statements, which are also subject to unknown and uncertain risks, uncertainties and other factors that could cause actual results to differ materially from any future results expressed or implied by such forward-looking statements. Readers are cautioned not to place undue reliance on these forward-looking statements.

Share Capital

Authorized capital:

25 million preference shares of no par value
Unlimited common shares of no par value

Issued and outstanding at August 25, 2009:

1,000 preference shares (held by a wholly-owned subsidiary of the Company)
145,833,219 common shares issued

Warrants outstanding at August 28, 2009 were 34,585,029 warrants (See table set forth under "**Liquidity and Capital Resources")**.

Agency Options outstanding at August 28, 2009 were 2,781,913 options. (See table set forth under "**Liquidity and Capital Resources")**.

Common stock options outstanding at August 28, 2009 were as follows:

Number Authorized	Date of Agreement	Exercise or Issue Price	Expiry Date
195,000	February 11, 2005	$1.00	February 11, 2010
450,000	April 21, 2005	$1.04	April 21, 2010
100,000	July 26, 2005	$0.95	July 26, 2010
50,000	December 28, 2005	$0.60	December 28, 2010
240,000	December 29, 2006	$0.59	December 29, 2011
1,440,000	December 21, 2007	$1.05	December 21, 2012
25,000	January 21, 2008	$1.05	January 21, 2013
25,000	February 7, 2008	$1.05	February 7, 2013
100,000	April 14, 2008	$1.15	April 14, 2013
150,000	April 29, 2008	$1.15	April 29, 2013
250,000	June 3, 2008	$1.17	June 3, 2013
1,225,000	June 30, 2008	$1.35	June 30, 2013
25,000	July 18, 2008	$1.20	July 18, 2013
125,000	October 9, 2008	$1.00	October 6, 2013
3,420,000	December 11, 2008	$0.30	December 11, 2013
320,000	March 11, 2009	$0.30	March 11, 2014
100,000	April 16, 2009	$0.44	April 16, 2014
8,240,000			