EAGLEFORD
ENERGY INC

FORM 51-101F1

STATEMENT OF RESERVES DATA
AND OTHER OIL & GAS INFORMATION

FOR THE YEAR ENDED
AUGUST 31, 2013

1 King Street West, Suite 1505, Toronto, ON, Canada Telephone: 416 364 4039, Facsimile: 416 364-8244

GLOSSARY OF TERMS

Natural Gas	
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
Oil and Natural Gas Liquids	
Bbl	Barrel
Mbbls	thousand barrels
Blpd	Barrels of liquid per day
Boe	Barrel of oil equivalent (1)
Bpd	Barrels per day
Boepd	Barrels of oil equivalent per day
Bopd	Barrels of oil per day
NGLs	Natural gas liquids

(1) A BOE conversion ratio of 6 Mcf: 1 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. Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation

The following table sets forth certain standard conversions factors between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
Metres	cubic feet	35.494
Bbls	cubic metres	0.159
Cubic metres	Bbls	6.289
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

DEFINITIONS

The following definitions form the basis of our classification of reserves and values presented in this report. They have been prepared by the Standing Committee on Reserves Definitions of the Petroleum Society of the CIM ("CIM"), incorporated in the Society of Petroleum Evaluation Engineers ("SPEE") Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and specified by National Instrument 51-101 ("NI 51-101").

Reserves are 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:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology;
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed; and
- a remaining reserve life of 50 years.

Reserves are classified according to the degree of certainty associated with the estimates.

Proved Reserves
Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable Reserves
Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Possible Reserves
Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. Possible reserves have not been considered in this report.

Other criteria that must also be met for the categorization of reserves are provided in Section 5.5 of the COGE Handbook.

Each of the reserves categories (proved, probable, and possible) may be divided into developed or undeveloped categories.

Developed Reserves
Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and nonproducing.

Developed Producing Reserves
Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed Non-Producing Reserves
Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

Undeveloped Reserves
Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator’s assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves
The qualitative certainty levels contained in the definitions in proved, probable and possible reserves are applicable to individual reserves entities, which refers to the lowest level at which reserves estimates are made, and to reported reserves, which refers to the highest level sum of individual entity estimates for which reserve estimates are made.

Reported total reserves estimated by deterministic or probabilistic methods, whether comprised of a single reserves entity or an aggregate estimate for multiple entities, should target the following levels of certainty under a specific set of economic conditions:

a. There is a 90% probability that at least the estimated proved reserves will be recovered.
b. There is a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered.
c. There is a 10% probability that at least the sum of the estimated proved reserves plus probable reserves plus possible reserves will be recovered.

A quantitative measure of the probability associated with a reserves estimate is generated only when a probabilistic estimate is conducted. The majority of reserves estimates will be performed using deterministic methods that do not provide a quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5.5.3 of the COGE Handbook. Whether deterministic or probabilistic methods are used, evaluators are expressing their professional judgement as to what are reasonable estimates.

Remaining Recoverable Reserves are the total remaining recoverable reserves associated with the acreage in which the Company has an interest.

Company Gross Reserves are the Company's working interest share of the remaining reserves, before deduction of any royalties.

Company Net Reserves are the gross remaining reserves of the properties in which the Company has an interest, less all Crown, freehold, and overriding royalties and interests owned by others.

Net Production Revenue is income derived from the sale of net reserves of oil, non-associated and associated gas, and gas by-products, less all capital and operating costs.

Fair Market Value is defined as the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.

Barrels of Oil Equivalent (BOE) Reserves – BOE is the sum of the oil reserves, plus the gas reserves divided by a factor of 6, plus the natural gas liquid reserves, all expressed in barrels or thousands of barrels. Equivalent reserves can also be expressed in thousands of cubic feet of gas equivalent (McfGE) using a conversion ratio of 1 bbl:6 Mcf.

Oil (or Crude Oil) – a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained from the processing of natural gas.

Gas (or Natural Gas) – a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs, but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.

Non-Associated Gas – an accumulation of natural gas in a reservoir where there is no crude oil.

Associated Gas – the gas cap overlying a crude oil accumulation in a reservoir.

Solution Gas – gas dissolved in crude oil.

Natural Gas Liquids – those hydrocarbon components that can be removed from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate, and small quantities of non-hydrocarbons.

FORWARD-LOOKING STATEMENTS

This statement of Reserves Data and Other Oil and Gas Information ("**Statement of Reserves**") contains forward-looking information and forward-looking statements (collectively "**forward-looking statements**"). These forward-looking statements relate to future events or the Corporation'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", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", and similar expressions. Such statements represent the Corporation's internal projections, estimates or beliefs concerning, among other things, an outlook on the estimated amounts and timing of capital expenditures, anticipated future debt levels and revenues or other expectations, beliefs, plans, objectives, assumptions, intentions or statements about future events or performance. These statements are not guarantees of future performance and involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in the forward-looking statements. In addition, this Statement of Reserves may contain forward-looking statements attributed to third party industry sources. Eagleford believes that the expectations reflected in those forward-looking statements are reasonable; however, undue reliance should not be placed in these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur.

Forward-looking statements in this Statement of Reserves include, but are not limited to, statements with respect to:

- the performance characteristics of the Company's oil and natural gas properties;
- the Company's oil and natural gas production levels;
- the size of the Company's oil and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- future development and exploration activities and the timing thereof;
- future land expiries;
- future liquidity and financial capacity;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditures programs.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of risk factors set forth below and elsewhere in this Statement of Reserves:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- general economic conditions in Canada and the United States;
- the ability of management to execute its business plan;
- risks and uncertainties involving geology of oil and gas deposits;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- risks inherent in marketing operations, including credit risk;
- the ability to enter into or renew leases;
- incorrect assessments of the value of acquisitions;
- potential delays or changes in plans with respect to exploration and development projects or capital expenditures;
- shut-ins of connected wells resulting from extreme weather conditions;
- insufficient storage or transportation capacity;
- hazards such as fire, explosion, blowouts, cratering and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury;
- geological, technical, drilling and processing problems; and

• changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry.

Statements relating to “reserves” are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Statement of Reserves are expressly qualified by this cautionary statement. Except as required by applicable securities law, Eagleford does not undertake any obligation to publicly update or revise any forward-looking statements. For additional risk factors, please see the Company’s Annual Information Form filed on Form 20F.

PART 1
DATE OF STATEMENT

Item 1.1 Relevant Dates:

1. Date of Statement: December 23, 2013
2. Effective Date of Statement: August 31, 2013
3. Preparation Date of Statement: December 4, 2013

PART 2
DISCLOSURE OF RESERVES DATA

2013

The Company has a 0.5% non-convertible gross overriding royalty in a natural gas well located in the Haynes area of Alberta and a 5.1975% interest in a natural gas unit located in the Botha area of Alberta, Canada both of which are carried on the consolidated statement of financial position at nil as at August 31, 2013.

For the year ended August 31, 2013 the Company recorded an impairment loss of $168,954 on its Botha, Alberta property as a result of no reserves and no future net revenue being assigned. During the year ended August 31, 2013, the producing wells in the Botha property watered out, are shut in and the operator does not intend on reactivating or remediating the wells.

As the Company had no reserves or future net revenue at August 31, 2013, the Company did not retain an independent reserves evaluator and accordingly there is no National Instrument Form 51-101F2 attached to this filing.

2012

In accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities, the Company's independent qualified reserves evaluator Sproule Associates Limited ("Sproule") prepared a report (the "Sproule Report") effective August 31, 2012 and dated October 11, 2012, using current geological and engineering knowledge, techniques and computer software. It was prepared within the Code of Ethics of the Association of Professional Engineers, Geologists and Geophysicists of Alberta ("APEGGA"). The Sproule Report adhered in all material aspects to the "best practices" recommended in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") which are in accordance with principles and definitions established by the Calgary Chapter of the Society of Petroleum Evaluation Engineers. The COGE Handbook is incorporated by reference in National Instrument 51-101. The Sproule Report evaluated 100% of Eagleford Energy Inc.'s ("Eagleford" or the "Company") natural gas reserves located in Canada, as at August 31, 2012.

For the years ended August 31, 2013 and 2012 the Company had not booked reserves for its Texas assets.

All monetary references contained in this Statement of Reserves Data and Other Oil and Gas Information are in Canadian dollars unless otherwise specified.

Item 2.1 **<u>Reserves Data (Forecast Prices and Costs):</u>**

1. <u>Breakdown of Reserves ((Forecast Case):</u>

Not Applicable as the Company has no reserves and no related future net revenue.

2. <u>Net Present Value of Future Net Revenue (Forecast Case):</u>

Not Applicable as the Company has no reserves and no related future net revenue.

3. <u>Additional Information Concerning Future Net Revenue (Forecast Case):</u>

Not Applicable as the Company has no reserves and no related future net revenue.

Item 2.2 **<u>Supplementary Disclosure (Constant Prices and Costs):</u>**

Not Applicable

Item 2.3 **<u>Reserves Disclosure Varies With Accounting:</u>**

Not Applicable

Item 2.4 **<u>Future Net Revenue Disclosure Varies With Accounting:</u>**

Not Applicable

PART 3
PRICING ASSUMPTIONS

Item 3.1 **<u>Constant Prices Used in Supplementary Estimates:</u>**

Not Applicable

Item 3.2 **<u>Forecasted Prices Used in Estimates:</u>**

Not Applicable as the Company has no reserves and no related future net revenue.

The weighted average historical natural gas price received by Eagleford for the year ended August 31, 2013 was $2.15/Mcf.

PART 4
RECONCILIATION OF CHANGES IN RESERVES

Item 4.1 **Reserves Reconciliation**

NI 51-101 Reconciliation of Company Gross [(1)] Reserves (Before Royalty) By Principal Product Type As of August 31, 2013 Forecast Prices and Costs			
	Associated and Non-Associated Gas		
Factors	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**
August 31, 2012	172	60	231
Technical Revisions	(159)	(60)	(218)
Production	(13)	-	(13)
August 31, 2013	Nil	Nil	Nil

(1) Gross Reserves means the Company's working interest reserves before calculation of royalties, and before consideration of the Company's royalty interests.

PART 5
ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 **Undeveloped Reserves:**

1. Proved Undeveloped Reserves:

Not Applicable

2. Probable Undeveloped Reserves:

Not Applicable

Item 5.2 **Significant Factors or Uncertainties Affecting Reserves Data:**

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economics data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs changes. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. These factors and assumptions include among others (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates, (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulation; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserves estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required for changes in well performance, prices, economic conditions and governmental restrictions. Revisions to reserve estimates can arise from changes in year–end prices, reservoir performance and geological conditions or production. These revisions can be either positive or negative.

Item 5.3 **<u>Future Development Costs:</u>**

Not Applicable

<u>PART 6</u>
<u>OTHER OIL AND GAS INFORMATION</u>

Item 6.1 **<u>Oil and Gas Properties and Wells:</u>**

1. <u>Properties, Plants, Facilities and Installations</u>

Properties:
All of the properties which the Company has an interest are located onshore in Canada and the United States.

Canada
At August 31, 2013 the Company had a 5.1975% working interest in a natural gas unit located in the Botha area Northwest, near the town of Manning, Alberta and a 0.5% overriding royalty in a natural gas well located in the Haynes area of Alberta, Canada both carried on the statement of financial position at nil. For the year ended August 31, 2013 the Company recorded an impairment loss of $168,954 on its Botha, Alberta property as a result of no reserves and no related future net revenue assigned. The remaining wells in the Botha gas unit watered out, are shut in and the operator of the natural gas unit does not intend on reactivating or remediating the wells.

United States
Matthews Lease, Zavala County, Texas

During the year ended August 31, 2012 the lessors of the Matthews lease, a property comprising approximately 2,629 gross acres of land in Zavala County, Texas (the "Matthews Property"), expressed their belief that the lease had terminated and filed a petition in the District Court, Zavala County, Texas, seeking a declaration that the lease had terminated. The Company disagreed and defended the action and countersued the lessors for repudiation of the lease seeking damages. During the year ended August 31, 2013, the Company entered into an agreement with the lessors of the Matthews Property, OGR Energy Corporation ("OGR Energy") and Texas Onshore Energy, Inc. (Texas together holding a 15% working interest in the Matthews Property with back in rights to earn an additional 15% working interest after production achieved $15.0 million of revenue. A new lease was signed with the Company's subsidiary, Eagleford Energy, Zavala, Inc. ("Zavala Inc.") effective September 1, 2013 (the "New Matthews Lease").

The New Matthews Lease has a primary term expiring January 31, 2014 (the "Primary Term") (subject to certain extensions) and can be maintained through the provision of certain royalty payments and the implementation of a continuous drilling program as follows.

A) The Company has agreed to a minimum annual royalty of $323.30 per acre retained on the Matthews Property to the Lessors payable as follows:

(1) US$150,000 upon execution of the Lease (paid)
(2) US$150,000 by the earliest of the following to occur:
(a) on or before 95 days from the Effective Date of the Lease (paid); or
(b) immediately prior to commencing a new operation under the terms of the Lease.

B) US$60,000 to Lessors upon commencement of the first new operation.

C) The Company has two (2) separate options to extend the Primary Term of the Matthews Lease. If the Company elects to extend the Primary Term of the Matthews Lease through February 28, 2014 (the "First Extension") the Company shall provide written notice and tender an additional pre-payment of royalties to Lessors in the amount of US$30,000 on or before January 26, 2013. If, after the First Extension has been exercised by the Company, and the Company elects to extend the Primary Term of the Matthews Lease through March 31, 2014 (the "Second Extension"), the Company shall provide written notice and tender an additional pre-payment of royalties to Lessors in the amount of US$30,000 on or before February 23, 2014.

D) Prior to the expiration of the Primary Term, the Company shall perform a new operation satisfied by either drilling a new well to a targeted depth deemed capable of production or the hydraulic fracturing of the existing Matthews #1H well (the "New Operation").

E) Beginning in the second lease year and continuing thereafter for each succeeding lease year drill at least 2 wells per year before the expiration of each lease year.

Upon the Company satisfying the New Operation, OGR Corporation and Texas Offshore will assign their working interests to Zavala Inc. and Zavala Inc.'s interest will increase to a 100% working interest in the Matthews Property from a 75% working interest before payout and a 61.50% working interest after payout of production revenue of $12.5 million and a 10% working interest before payout and a 7.5% working interest after payout of production revenue of $15 million held by Eagleford with the balance held by OGR Energy and Texas Onshore. The royalties payable under the Matthews Lease are 25%.

On December 3, 2013, the Company entered into an agreement with Stratex Oil and Gas Holdings, Inc. ("Stratex") to develop the Matthews Lease in Zavala County, Texas (the "Joint Development Agreement"). Under the terms of the Joint Development Agreement, Stratex may earn a 66.67% working interest before payout (50% working interest after payout) in the Matthews #1 well by:

1) completing a hydraulic fracture no later than March 31, 2014;
2) delivering US$150,000 to the lessors of the Matthews Lease upon execution of the Joint Development Agreement (paid);
3) delivering US$50,000 to the Company upon execution of the Joint Development Agreement (paid); and
4) delivering US$100,000 to the Company on or before December 31, 2013.

Following the completion of the above, Stratex will earn a 50% working interest in the 2,629 acre Matthews Lease excluding 80 acres surrounding the Matthews #3 well.

Murphy Lease, Zavala County, Texas

At August 31, 2013 the company holds through Dyami Energy a 100% working interest in the Murphy Lease comprising approximately 2,637 acres of land in Zavala County, Texas subject to a 10% carried interest on the drilling costs from surface to base of the Austin Chalk formation, and a 3% carried interest on the drilling costs from the top of the Eagle Ford shale formation to basement on the first well drilled into a serpentine plug and for the first well drilled into a second serpentine plug, if discovered. Thereafter Dyami Energy's working interests range from 90% to 97%. The royalties payable under the Murphy Lease are 25%.

Dyami Energy is required to drill a well every six months in order to maintain the Murphy Lease. Three years after the cessation of continuous drilling, all rights below the deepest producing horizon in each unit then being held by production, shall be released and re-assigned to the lessor, unless the drilling of another well has been proposed on said unit, approved in writing by lessor, and timely commenced. Dyami Energy has received an extension of the Murphy Lease until January 31, 2014 to perform its obligations thereunder.

Acreage:

The following table sets forth the developed acreage of the projects in which the Company holds an interest, on a gross and a net basis as of August 31, 2013, 2012 and 2011. The developed acreage is stated on the basis of spacing units designated by provincial authorities and typically on the basis of 160 acre spacing unit for oil production and 640 acre spacing unit for gas production in Alberta, Canada. Our developed acreage is as follows:

August 31	**2013**		**2012**		**2011**	
Alberta, Canada	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Leasehold Acreage-Developed	8,320	432.43	8,320	432.43	8,320	432.43

2. Producing and Non Producing Wells:

The following table sets forth the number of Eagleford's gross and net oil and gas wells producing and non-producing in Alberta, Canada as of August 31, 2013, 2012 and 2011. A gross well is a well in which the Company owns an interest. A net well represents the fractional interest the Company owns in gross wells.

August 31	**2013**		**2012**		**2011**	
Alberta, Canada	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Natural Gas Wells-Producing	0.0	.0	3.0	.15525	3.0	.15525
Natural Gas Wells-Non Producing	9.0	.4657	6.0	.3105	6.0	.3105

Item 6.2 Properties With No Attributed Reserves:

At August 31, 2013 the Company had a 5.1975% working interest in a natural gas unit located in the Botha area Northwest, near the town of Manning, Alberta. For the year ended August 31, 2013 the Company recorded an impairment loss of $168,954 on its Botha, Alberta property as a result of no reserves or value being assigned. The remaining wells in the gas unit watered out and are shut in and the operator of the natural gas unit does not intend on reactivating or remediating the wells.

At August 31, 2013 the Company has an interest in two leases covering approximately 5,266 gross acres of land in Zavala County, Texas, United States where no reserves have been assigned (See Item 6.1 above).

Acreage:

The following table sets forth the acreage of the Zavala County, Texas projects in which the Company holds an interest, on a gross and a net basis as of August 31, 2013, 2012 and 2011:

August 31	**2013**		**2012**		**2011**	
Texas, USA	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Leasehold Acreage-Undeveloped	5,266	4,793	5,266	4,793	5,266	4,793

Non Producing Wells:

The following table sets forth the number of Eagleford's gross and net non-producing oil and gas wells in Texas, USA as of August 31, 2013, 2012 and 2011. A gross well is a well in which the Company owns an interest. A net well represents the fractional interest the Company owns in gross wells.

August 31	**2013**		**2012**		**2011**	
Texas, USA	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil Wells – Non Producing	7.0	6.60	7.0	6.60	4.0	3.80

Item 6.2.1 Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

A part of the Company's oil and gas development program, significant capital expenditures are required to develop and maintain the Company's Texas Leases in good standing. The amount expended on future exploration and development on these leases is dependent on the nature of those opportunities evaluated by the Company. Any additional expenditures on the leases will be required to be funded by additional share capital issuances or debt issued by the Company, or by other means. At this time, no assurances can be made that the Company's Texas Leases will economically produce commercial quantities of oil and gas or that the Company will obtain the necessary financing to fully develop its Leases.

Item 6.3 Forward Contracts:

The Company has no forward contracts.

Item 6.4 Additional Information Concerning Abandonment and Reclamation Costs:

The Company bases its estimates for costs of abandonment and reclamation of surface leases and wells, net of estimated salvage value, on previous experience with similar well site locations and terrain, estimates obtained from area operators and various regulatory abandonment guidelines and requirements. The Company believes that its range of estimates per well for abandonment and reclamation costs are reasonable and applicable to its wells. Ultimately all wells in which the Company has an interest will require abandonment and reclamation.

The Company's abandonment and reclamation obligations result from its ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The total obligation is estimated based on the Company's net ownership interest in 7.07 net wells. The Company has estimated the net present value of these obligations to be $119,742 at August 31, 2013 based on an undiscounted total future liability of $166,578. These payments are expected to be incurred between fiscal 2014 and 2031.

Item 6.5 Tax Horizon:

The Company has unused capital losses in the amount of approximately $195,852 which may be carried forward indefinitely to offset future capital gains, and unused non capital losses in the amount of approximately $3,055,153 available to reduce income in future years and does not anticipate paying significant income taxes in the near term.

Item 6.6 Costs Incurred:

For the year ended August 31, 2013, the Company incurred the following costs:

Property and equipment	
Developed - Canada	
Net book value at August 31, 2012	$175,000
Change in decommissioning obligation estimates	(4,166)
Depletion	(10,212)
Impairment	(168,954)
Balance August 31, 2013	**Nil**
Exploration and evaluation assets	
Balance August 31, 2012	$8,475,487
Additions	404,818
Change in decommissioning obligation estimates	(9,268)
Impairment	(2,690,568)
Foreign exchange	354,809
Balance August 31, 2013	**$6,535,278**

As at and for the years ended August 31, 2013 no general and administrative costs were capitalized. For the year ended August 31, 2013, the Company recorded an impairment loss of $168,954 on its Botha, Alberta, Canada property as a result of no reserves or future net revenue being assigned. The remaining wells on the Botha property watered out, are shut in and the operator of the property does not intend on reactivating or remediating the wells.

The Company's exploration and evaluation assets are located in Texas, USA. As at and for the year ended August 31, 2013 the Company record an impairment of $2,690,568 on its Murphy Lease, Zavala County, Texas based on the amount for which management believes the assets could be sold or farmed out in an arms' length transaction, less estimated costs to sell. Included in the above additions for the year ended August 31, 2013, the Company capitalized borrowing costs interest of $240,092 to exploration and evaluation assets.

Item 6.7 Exploration and Development Activities:

During the fiscal year ended August 31, 2013, the Company drilled no exploratory wells on its leases located in Zavala County, Texas USA.

The following table sets forth the number of Eagleford's gross and net exploratory wells drilled in Texas, USA during the year ended August 31, 2013, 2012 and 2011. A gross well is a well in which the Company owns an interest. A net well represents the fractional interest the Company owns in gross wells

August 31	2013		2012		2011	
Texas, USA	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil Wells – Non Producing	-	-	3.0	2.70	4	3.80

During fiscal 2012, the Company drilled the Dyami/Murphy #4 well, the Dyami/Murphy #3 and the Dyami/Matthews #2 well.

Item 6.8 Production Estimates:

Not Applicable as the Company has no reserves and no related future net revenue.

Item 6.9 Production History:

1. The following table sets forth certain information in respect of production, product prices received, production costs and netbacks received by the Company for each quarter of fiscal 2013. During the quarter ended August 31, 2013 the Company's remaining wells in the Botha gas unit watered out and were shut in.

Production History	Fiscal 2013			
	August 31	**May 31**	**February 28**	**November 30**
Average Daily Production				
Natural gas (Mcf per day)	-	49	51	50
Average Commodity Prices				
Natural gas ($/Mcf)	-	$3.05	$2.72	$2.62
Royalties				
Natural gas ($/Mcf)	-	$0.57	$0.59	$0.40
Production Costs				
Natural gas ($/Mcf)	-	$0.43	$0.56	$0.53
Netback by Product				
Natural gas ($/Mcf)	-	$2.05	$1.57	$1.69

2. The following table indicates the Company's total production for fiscal 2013 from its core property.

Property	Associated and Non-Associated Gas (MMcf)
Botha, Alberta	13