FORM 51-101F1

**STATEMENT OF RESERVES DATA
AND OTHER OIL & GAS INFORMATION**

**FOR THE YEAR ENDED
AUGUST 31, 2012**

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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.

PART 1
DATE OF STATEMENT

Item 1.1 **Relevant Dates:**

1.	Date of Statement:	December 21, 2012
2.	Effective Date of Statement:	August 31, 2012
3.	Preparation Date of Statement:	November 28, 2012

PART 2
DISCLOSURE OF RESERVES DATA

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 adheres 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. The Company has not booked reserves for its Texas assets.

The tables below are summaries of the Company's natural gas reserves and the net present value of future net revenue attributable to such reserves as evaluated in the Sproule Report based on forecast price and cost assumptions. The tables summarize the data contained in the Sproule Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the Company's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by Sproule. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Company's reserves estimated by Sproule represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of our natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The Sproule Report is based on certain factual data supplied by the Company and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company's natural gas property and contracts (except for certain information residing in the public domain) were supplied by the Company to Sproule and accepted without and further investigation. Sproule accepted this data as presented and neither title searches nor field inspections were conducted. The Company's interests covered by the Sproule Report are located in the Province of Alberta, Canada.

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>

NI 51-101 Summary of Oil and Gas Reserves As of August 31, 2012 Forecast Prices and Costs		
	Reserves	
	Natural Gas (non-associated & associated)	
Reserves Category	**Gross (MMcf)**	**Net (MMcf)**
Proved		
Developed Producing	172	137
Total Proved	**172**	**137**
Probable	60	45
Total Proved Plus Probable	**231**	**182**

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

NI 51-101 Summary of Net Present Values of Future Net Revenue As of August 31, 2012 Forecast Prices and Costs						
	Net Present Values of Future Net Revenue					
	Before Income Taxes Discounted at (%/Year)					Before Tax Net Value 10%/yr ($/boe)
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	
Proved						
Developed Producing	308	202	142	106	83	6.22
Total Proved	**308**	**202**	**142**	**106**	**83**	**6.22**
Probable	148	65	32	18	11	4.33
Total Proved Plus Probable	**456**	**266**	**175**	**124**	**94**	**5.75**

Notes: Net Present Value of Future Net Revenue includes all resource income:
Sale of oil, gas, by-product reserves
Processing third party reserves
Other income

Unit Values are based on net reserve volumes

3. Additional Information Concerning Future Net Revenue (Forecast Case):

NI 51-101 Total Future Net Revenue Undiscounted As of August 31, 2012 Forecast Prices and Costs						
Reserves Category	**Revenue (M$)**	**Royalties (M$)**	**Operating Costs (M$)**	**Development Costs (M$)**	**Well Abandon-ment/Other Costs (M$)**	**Future Net Revenue Before Income Taxes (M$)**
Proved	921	167	442	0	5	308
Proved Plus Probable	1,351	259	630	0	5	456

NI 51-101 Net Present Value of Future Net Revenue By Production Group As of August 31, 2012 Forecast Prices and Costs			
Reserves Category	**Production Group**	**Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)**	**Unit Value Before Income Taxes (Discounted at 10%/Year) ($/boe)**
Proved	Natural Gas (including associated by-products)*	142	6.22
Proved Plus Probable	Natural Gas (including associated by-products)*	175	5.75

*Includes corporate Capital GCA, if applicable
Unit values are based on net reserve volumes

Item 2.2 **Supplementary Disclosure (Constant Prices and Costs):**

Not Applicable

Item 2.3 **Reserves Disclosure Varies With Accounting:**

Not Applicable

Item 2.4 **Future Net Revenue Disclosure Varies With Accounting:**

Not Applicable

PART 3
PRICING ASSUMPTIONS

Item 3.1 **Constant Prices Used in Supplementary Estimates:**

Not Applicable

Item 3.2 **Forecasted Prices Used in Estimates:**

Forecast Prices (as determined by Sproule Associates Limited).

NI 51-101 Summary of Pricing and Inflation Rate Assumptions As of August 31, 2012 Forecast Prices and Costs								
Year	**WTI Cushing Oklahoma ($US/bbl)**	**Edmonton Par Price 40° API ($Cdn/bbl)**	**Cromer Medium 29.3° API ($Cdn/bbl)**	**Natural Gas (1) AECO Gas Prices ($Cdn/MMBtu)**	**Pentanes Plus F.O.B. Edmonton ($Cdn/bbl)**	**Butanes F.O.B. Edmonton ($Cdn/bbl)**	**Inflation Rate (2) (%/Yr)**	**Exchange Rate (3) ($US/ $Cdn)**
Historical								
2007	72.27	77.06	65.36	6.65	77.33	63.71	2.0	0.935
2008	99.59	102.85	93.05	8.15	104.70	75.09	1.1	0.943
2009	61.63	66.20	62.77	4.19	68.13	49.34	2.0	0.880
2010	79.43	77.80	73.67	4.16	84.21	57.99	1.2	0.971
2011	95.00	95.16	87.86	3.72	104.12	70.93	1.5	1.012
Forecast								
2012	92.25	88.03	80.99	2.74	98.36	65.62	2.0	0.992
2013	93.57	94.36	86.81	3.28	101.03	70.33	2.0	0.992
2014	91.20	91.97	84.61	3.68	98.47	68.55	2.0	0.992
2015	91.79	92.57	85.16	4.45	99.11	68.99	2.0	0.992
2016	99.37	100.21	92.19	5.82	107.29	74.69	2.0	0.992
2017	101.35	102.21	94.03	5.94	109.44	76.18	2.0	0.992
2018	103.38	104.25	95.91	6.06	111.62	77.71	2.0	0.992
2019	105.45	106.34	97.83	6.19	113.86	79.26	2.0	0.992
2020	107.56	108.47	99.79	6.32	116.13	80.85	2.0	0.992
2021	109.71	110.64	101.79	6.45	118.46	82.46	2.0	0.992
2022	111.90	112.85	103.82	6.59	120.83	84.11	2.0	0.992
Thereafter escalation rate of at 2%								

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.

Notes:
Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

The weighted average historical natural gas price received by Eagleford for the year ended August 31, 2012 was $2.24/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, 2012 Forecast Prices and Costs			
	Associated and Non-Associated Gas		
Factors	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**
August 31, 2011	203	66	269
Technical Revisions	(11)	(6)	(18)
Production	(20)	-	(20)
August 31, 2012	172	60	231

(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

PART 6
OTHER OIL AND GAS INFORMATION

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, 2012 the Company has 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.

United States
Matthews Lease, Zavala County, Texas

At August 31, 2012 the Company holds through its wholly owned subsidiary Dyami Energy Inc. ("Dyami Energy") a 75% working interest before payout which reduces to a 61.50% working interest after payout of $12,500,000 of production revenue and directly a 10% working interest before payout which reduces to a 7.50% working interest after payout of $15,000,000 of production revenue subject to the Farmout Agreement below.

The Matthews lease comprises approximately 2,629 gross acres of land in Zavala County, Texas. The royalties payable under the Matthews lease are 25%.

On March 31, 2011 the Company entered into a Farmout Agreement (the "Farmout") from surface to the base of the San Miguel formation (the "San Miguel") on the Matthews Lease. Under the terms of the Farmout, the farmee may earn an initial 25% of the Company's working interest in the San Miguel formation by paying 100% of the costs to drill, complete, equip and perform an injection operation on a vertical test well to a depth of approximately 3,500 feet. To date, the farmee has not paid the full costs and the Company has not assigned any interest to the farmee in the San Miguel formation.

Matthews Lease Litigation
The lessors of the Matthews Lease expressed their belief that the lease has terminated and filed a petition in the District Court, Zavala County, Texas, seeking a declaration that the lease has terminated. The Company disagrees and believes that it is in full compliance with the terms of the lease. The Company is defending the allegation and countersuing the lessor for repudiation of the lease and seeking damages (see Item 6.2.1).

At August 31, 2012 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%.

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, 2012. 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	**2012**		**2011**		**2010**	
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, 2012. 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	**2012**		**2011**		**2010**	
Alberta, Canada	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Natural Gas Wells-Producing	3.0	.15525	3.0	.15525	3.0	.15525
Natural Gas Wells-Non Producing	6.0	.3105	6.0	.3105	6.0	.3105

Item 6.2 Properties With No Attributed Reserves:

At August 31, 2012 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.

Matthews Lease, Zavala County, Texas

Dyami Energy holds a 75% working interest before payout and a 61.50% working interest after payout of production revenue of $12.5 million and Eagleford holds a 10% working interest before payout and a 7.5% working interest after payout of production revenue of $15 million in a mineral lease comprising approximately 2,629 gross acres of land in Zavala County, Texas. The royalties payable under the Matthews Lease are 25%.

Dyami Energy is the designated operator under the provisions of the Matthews Lease Operating Agreement.

The Matthews Oil and Gas Lease had a primary term of three years commencing April 1, 2008, unless commercial production is established from a well or lands pooled therewith or the lessee is then engaged in actual drilling or reworking on any well within 90 days thereafter. The lease shall remain in force so long as the drilling or reworking is processed without cessation of more than 90 days. Once production is established, the lease is held by production so long as a new well is commenced within 180 days of completion of the prior well, which is defined as 15 days following reaching total depth in a well or the total length of a horizontal well.

Matthews Lease Litigation
The lessors of the Matthews lease expressed their belief that the lease has terminated and filed a petition in the District Court, Zavala County, Texas, seeking a declaration that the lease has terminated. The Company disagrees and believes that it is in full compliance with the terms of the lease. The Company is defending the allegation and countersuing the lessors for repudiation of the lease and seeking damages (see Item 6.2.1).

Murphy Lease, Zavala County, Texas

Dyami Energy holds a 100% working interest in a mineral lease comprising approximately 2,637 acres of land in Zavala County, Texas (the "Murphy Lease") 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 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.

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, 2012:

August 31	**2012**		**2011**		**2010**	
Texas, USA	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Leasehold Acreage-Undeveloped	5,266	4,793	5,266	4,793	5,266	4,872

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, 2012. 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	**2012**		**2011**		**2010**	
Texas, USA	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil Wells – Non Producing	7.0	6.6	4.0	3.80	Nil	Nil

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.

Matthews Lease Litigation

The lessor of the Matthews lease expressed their belief that the lease has terminated and filed a petition in the District Court, Zavala County, Texas, seeking a declaration that the lease has terminated. The Company disagrees and believes that it is in full compliance with the terms of the lease. The Company is defending the allegation and countersuing the lessor for repudiation of the lease and seeking damages.

The Company elected to conduct the continuous drilling program provision of the lease in order to extend the term of the lease beyond its primary term. The Company commenced actual drilling operations on a well, within the 180 day time period allowed and defined in the amended lease every such period since the end of the primary term.

In March 2012**,** the Company notified the lessor of its intention to continue drilling the 2-H well initiated in October 2011 and suspended, and to drill a new well, the 4-H under the continuous-drilling program.

Upon receipt of this notice, and before the 180-day deadline to commence actual drilling operations expired, the lessor informed the Company that it was taking the position that the lease had terminated because the Company allegedly failed to drill the No. 2-H well in a good faith attempt to secure production, and thus failed to comply with the continuous drilling program. The lessor later added that the Company was 2 days late having a drill bit contact the surface of the earth and turn to the right. Based on the Company's extensive logging, coring, and laboratory work and analysis, the Company was highly confident that these wells would produce in commercial quantities, which would have benefitted the lessor and the other royalty owner, and would have allowed the Company to begin to recoup its investment in the lease. Extended development drilling would have followed. Accordingly the Company is seeking specific performance or damages from the Lessors.

As at August 31, 2012, no amounts of contingent loss due to the impairment of the above mentioned lease have been recorded in these consolidated financial statements. According to the Company's legal counsel, there are no dispositive motions pending, a trial date has not been set and in their opinion it is not possible to evaluate the likelihood of an unfavorable outcome or the amount or range of potential loss.

The Company carries its investment in the Matthews lease at approximately $4,645,534. If the final outcome of such claim differs adversely from that expected, it would result in an impairment loss equal to the carrying value of the Matthews lease, when determined.

Item 6.3 **<u>Forward Contracts:</u>**

The Company has no forward contracts.

Item 6.4 **<u>Additional Information Concerning Abandonment and Reclamation Costs:</u>**

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. The Company's independent qualified reserves evaluator has also estimated similar costs in deriving the Company's estimate of future net revenue. The following table accounts for costs for only the wells which were evaluated by Sproule and have not included other shut-in, suspended or uncompleted wells in which the Company has an interest.

Year	Proved		Proved plus Probable	
	Undiscounted	Discounted at 10%	Undiscounted	Discounted at 10%
	$M	$M	$M	$M
2031	5	1	5	0

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 $114,755 at August 31, 2012 based on an undiscounted total future liability of $158,974. These payments are expected to be incurred between fiscal 2022 and 2031.

Item 6.5 **Tax Horizon:**

The Company has non-capital losses of $2,225,622 at August 31, 2012 and does not anticipate paying significant income taxes in the near term.

Item 6.6 **Costs Incurred:**

For the year ended August 31, 2012, the Company incurred the following costs:

Property, plant and equipment	
Developed - Canada	
Net book value at August 31, 2011	$243,000
Change in decommissioning obligation estimates	819
Depletion	(18,045)
Impairment	(50,774)
Balance August 31, 2012	**$175,000**
Exploration and evaluation assets	
Balance August 31, 2011	$8,995,878
Additions	1,559,763
Units cancelled	(2,091,616)
Decommissioning obligations	41,243
Change in decommissioning obligation estimates	6,546
Foreign exchange	(36,327)
Balance August 31, 2012	**$8,475,487**

For the year ended August 31, 2012 the Company capitalized interest of $289,650 to exploration and evaluation assets (August 31, 2011: $197,690).

Item 6.7 **Exploration and Development Activities:**

During the fiscal year ended August 31, 2012, the Company drilled three 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, 2012. 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	2012		2011		2010	
Texas, USA	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil Wells – Non Producing	3.0	2.7	4.0	3.80	Nil	Nil

During fiscal 2012, the Company drilled the Dyami/Murphy #4 well, the Dyami/Murphy #3 and the Dyami/Matthews #2 well. The Company is reviewing frac design and completions programs from industry specialists.

Item 6.8 <u>Production Estimates:</u>

The following table indicates the volume of production estimated for the first year reflected in the estimates of gross proved reserves and gross probable reserves based on forecast prices and costs.

Property	Associated and Non-Associated Gas (MMcf) Proved	Associated and Non-Associated Gas (MMcf) Probable
Botha, Alberta, Canada	14	0

Item 6.9 <u>Production History:</u>

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 2012.

Production History	Fiscal 2012			
	August 31	**May 31**	**February 28**	**November 30**
Average Daily Production				
Natural gas (Mcf per day)	54	54	54	52
Average Commodity Prices				
Natural gas ($/Mcf)	$1.92	$1.56	$2.42	$3.21
Royalties				
Natural gas ($/Mcf)	$0.38	$0.41	$0.70	$0.72
Production Costs				
Natural gas ($/Mcf)	$0.54	$2.55	$2.20	$1.83
Netback by Product				
Natural gas ($/Mcf)	$1.00	$(1.40)	$(0.48)	$0.66

2. The following table indicates the Company's total production for fiscal 2012 from its core property.

Property	Associated and Non-Associated Gas (MMcf)
Botha, Alberta	20

Form 51-101F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the Board of Directors of Eagleford Energy Inc. (the "Company"):

1. We have evaluated the Company's Reserves Data as at August 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at August 31, 2012, estimated using forecast prices and costs.

2. The Reserves Data are the responsibility of the Company's management. Our responsibility is to express an opinion on the Reserves Data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of August 31, 2012, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	Evaluation of the P&NG Reserves of Eagleford Energy Inc., As of August 31, 2012, prepared in September and October 2012	Canada				
Total			**Nil**	**175**	**Nil**	**175**

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
October 11, 2012

Original Signed by “Attila A. Szabo”, P. Eng.

____
Attila A. Szabo, P. Eng.,
Project Leader,
Senior Petroleum Engineer and
Partner

Original Signed by “Cameron P. Six”, P.Eng.

____
Cameron P. Six, P.Eng.
Vice-President, Engineering and Partner

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Eagleford Energy Inc. ("the Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at August 31, 2012, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation and in the event of a proposal to change the independent qualified reserves evaluator, to inquire whether there had been disputes between the previous independent qualified reserves evaluator and management; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing the reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

<u>"JAMES CASSINA"</u>
James Cassina, President, Secretary and Director

<u>"MILTON KLYMAN"</u>
Milton Klyman, Director

<u>"COLIN MCNEIL"</u>
Colin McNeil, Director

<u>"ALAN GAINES"</u>
Alan Gaines, Director

December 28, 2012