Management's Discussion and Analysis ("MD&A")

For the three and nine months ended September 30, 2011

Dated November 9, 2011

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EPSILON ENERGY LTD.
MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2011

This Management's Discussion and Analysis ("**MD&A**") is intended to assist in the understanding of trends and significant changes in or results of operations and the financial condition of Epsilon Energy Ltd. ("**Epsilon**" or the "**Corporation**") for the periods presented. The MD&A has been prepared by management as at September 30, 2011 in accordance with International Financial Reporting Standard 1, "First-time Adoption of International Financial Reporting Standards", and with International Accounting Standard 34, "Interim Financial Reporting", as issued by the International Accounting Standards Board. Previously, the Corporation prepared its Interim and Annual Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles. Production volumes are presented on an after royalties basis. This document is dated November 8, 2011.

This MD&A should be read in conjunction with the unaudited interim consolidated financial statements as at September 30, 2011 and for the three and nine months ended September 30, 2011 and 2010, the audited consolidated financial statements as at December 31, 2010 and 2009 and for the years then ended together with accompanying notes, the Statement of Reserves Data and Other Oil and Gas Information at December 31, 2010, the Annual Information Form ("**AIF**") dated March 31, 2011 and Form 51-101 F3 "*Report of Management and Directors on Reserves Data and Other Information*" dated March 31, 2011. These documents and additional information about Epsilon are available on SEDAR at www.sedar.com.

Unless otherwise indicated, all dollar values in this MD&A are, with the exception of per unit amounts, expressed in thousands of U.S. dollars. Canadian dollars are expressed as C$ in this MD&A.

Cautionary Statement Regarding Forward Looking Information and Statements

Certain statements contained in this report constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions and statements relating to matters that are not historical facts constitute "forward looking information" within the meaning of applicable Canadian securities legislation. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated. Such forward-looking statements are based on reasonable assumptions but no assurance can be given that these expectations will prove to be correct and the forward-looking statements included in this report should not be unduly relied upon. These statements are made only as of the date of this report.

In particular, this report contains forward-looking statements including, but not limited to, the following:

- oil and natural gas production rates;
- commodity prices for crude oil or natural gas;
- supply and demand for oil and natural gas;
- the estimated quantity of oil and natural gas reserves, including reserve life;
- capital expenditure programs;
- future exploration, development and production costs;
- timing of drilling plans;
- planned construction and expansion of facilities;
- plans for and results of exploration and development activities;
- expectations regarding the Corporation's ability to raise capital and to continually add to oil and natural gas reserves through acquisitions, exploration and development; and
- treatment under governmental regulatory regimes and tax laws.

The Corporation'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 report:

- general economic, political, market and business conditions;
- risks inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for capital, acquisitions of reserves, undeveloped lands, drilling equipment and skilled personnel;
- geological, technical, drilling and processing problems;
- incorrect assessments of the value of acquisitions;
- the availability of capital on acceptable terms;
- volatility in market prices for oil and natural gas;
- reliance on key operational and management personnel;
- actions by governmental authorities, including regulatory, environmental and taxation policies;
- fluctuations in foreign exchange, interest rates and stock market volatility; and
- other risk factors discussed under "*Risk Factors*" within the Corporation's AIF dated March 31, 2011.

These factors are not all inclusive. Except as required under applicable securities laws, the Corporation undertakes no obligation to update or revise any forward-looking statements.

Epsilon's Strategic Objectives

Epsilon is engaged in the acquisition, exploration, development and production of natural gas reserves targeting the Marcellus shale. The Corporation also has participating interests and production sharing agreements in other natural gas and oil plays within Canada, the US and Ethiopia. Established in 2005, the Corporation has been a producer of natural gas and oil since 2006. Epsilon's ongoing business strategy involves focused targeting of natural gas and oil properties within the United States and Canada, as well as the high potential oil and gas properties in Africa with the goal of converting its leasehold interests into proven natural gas and oil reserves, followed by production that optimizes cash flow and return on investment. The common shares of the Corporation trade on The Toronto Stock Exchange under the symbol "EPS". Also refer to "*Risk Factors*" in the Corporation's Annual Information Form dated March 31, 2011.

Epsilon's Business

Epsilon consists of three main companies that represent the Corporation's operating and reportable segments as follows:

Epsilon Energy Ltd. – includes the exploration for, development of, and production of oil and natural gas, within Canada. The key resource plays are 1) Bakken and Midale in Saskatchewan and 2) Yamaska, Gaspe, Dundee and St. Jean in Quebec.

Epsilon Energy USA, Inc. – includes the exploration for, development of, and production of oil and natural gas in the US. The key resource plays are 1) Marcellus in Pennsylvania, 2) Oriskany and Marcellus in New York and 3) Lower Smackover in Mississippi.

Epsilon Energy Ethiopia Ltd. - includes the exploration for, development of, and production of oil and natural gas in northwest Ethiopia pursuant to a Production Sharing Agreement with the Ministry of Mines and Energy in Democratic Republic of Ethiopia.

Changes in Accounting Policies

On January 1, 2011, Epsilon adopted International Financial Reporting Standards ("IFRS") for financial reporting purposes, using a transition date of January 1, 2010. The financial statements for the three months ended March 31, 2011, the three and six months ended June 30, 2011 and the three and nine months ended September 30, 2011, including required comparative information, have been prepared in accordance with International Financial Reporting Standards 1, *First-time Adoption of International Financial Reporting Standards,* and with International Accounting Standard ("IAS") 34, *Interim Financial Reporting,* as issued by the International Accounting Standards Board ("IASB"). Previously, the Corporation prepared its interim and annual Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("GAAP"). The adoption of IFRS has not had a material impact on the Corporation's operations, strategic decisions or cash flows. The most significant changes to the Corporation's accounting policies relate to the accounting for oil and natural gas interests.

Further information on the IFRS impacts is provided in the Accounting Policies and Estimates section of this MD&A, including reconciliations between previous GAAP and IFRS Net Earnings and other financial metrics.

RECENT EVENTS

Chesapeake operations
Epsilon noted that Chesapeake Energy Corp. (Chesapeake) has voluntarily suspended all of their hydraulic fracturing procedures in Pennsylvania as of April 21, 2011, due to an unexpected chemical leak during frac'ing, to evaluate the cause. On May 13, 2011, Chesapeake lifted the suspension on its frac'ing procedures and operations have resumed.

During period ended June 30, 2011, Chesapeake fulfilled its first earning period carry obligation of $50.0 million. Epsilon derecognized 25% of its assets pertaining to the Farmout Agreement assignable to Chesapeake, and recognized a gain on disposal of the assets.

On August 31st, the Corporation completed and signed an Interim Agreement for Gas Gathering Systems in its Marcellus Shale project with partners Chesapeake, Statoil USA Onshore Properties, Inc (Statoil) and their respective affiliates. This agreement governs both current and future gathering systems for the project, in which Epsilon holds a 35% interest. Chesapeake and Statoil hold the remaining 65% interests.

NY Asset reallocation
In New York, Epsilon signed a Memorandum of Understanding, effective July 31, 2011, in which all jointly-held properties are to be divided in half. Two asset lists were prepared containing the following split in properties:

Asset List A – contains all Trenton Black River wells producing and non-producing, and its associated reserves and leasehold being held by those wells, and all claims to participation rights on certain wells/pipeline systems.

Asset List B – contains all remaining undeveloped acreage leasehold and right of ways, all shut in Oriskany wells, one Trenton Black River well with associated claim to participation rights, tap site property and purchased seismic data.

Epsilon selected Asset List B, and assigned its interest (approx. 50%) of the assets in list A to its joint-venture partners, while receiving the remaining interest (approx. 50%) of the assets in list B.

As of October 31, the asset reallocation was finalized.

Appointment of Interim CFO
Effective June 23, 2011, the Corporation appointed Kar Yong as interim Chief Financial Officer. Mr. Yong has assumed the CFO responsibilities from Mr. Arandjelovic while the board of directors continues its search for a permanent CFO. Mr. Yong has been a Chartered Accountant over 35 years, working as an external auditor and in financial analysis of a number of private and public companies, including 25 years with Ultramar.

Appointment of COO
Effective October 18, 2011, the Corporation appointed Ramik Arandjelovic as Chief Operating Officer. Mr. Arandjelovic will be responsible for the strategic and operational leadership of Epsilon, overseeing corporate operations and engineering related activities. Mr. Arandjelovic has a strong background and experience in both engineering and economics, having received a Bachelor of Applied Science and a Bachelor of Arts in Economics from Queen's University. He has spent considerable time in all facets of upstream and midstream operations, from drilling and completion to production, gathering and marketing. Mr. Arandjelovic has previously worked for Epsilon in the capacity of New York Project Manager, followed by being the Director of Operations.

OVERALL PERFORMANCE

At September 30, 2011, the Corporation generated a net income of approximately $24.7 million as compared to $1.2 million in 2010. At September 30, 2011, the Corporation had surplus working capital (inclusive of $0.3 million restricted cash) of approximately $18.2 million, as compared to $20.3 million of surplus working capital (inclusive of $0.7 million restricted cash) at December 31, 2010. The Corporation has net cash flows provided by operations of $0.2 million in 2011 compared to $5.4 million in 2010. Epsilon has no debt.

Operational Outlook and Property Overview

A summary of the Epsilon's projects by country are as follows:

United States

Pennsylvania Marcellus Shale

As of September 30, 2011, the Corporation had approximately 11,500 gross (5,750 net) leasehold acres in Pennsylvania where Chesapeake is the operator. As of November 1, the Corporation has either drilled or participated in the drilling of 72 wells in the Marcellus shale on its Highway 706 project in northeastern Pennsylvania. Fifteen of the wells are currently producing at a combined net average rate of 11.1 Mmcf per day. Two compressors have been in operation with total gross capacity of 10 Mmcf per day, and further pipeline construction is underway to expand the infrastructure and its capacity.

Mississippi

On October 1, 2010, the Corporation signed Participation Agreement (the "Agreement") with a large US-based private land owner ("land owner") to explore for and produce oil and gas. Under the principal terms of the Agreement, Epsilon is committed to drill a minimum of two horizontal wells within one year from the effective date of the agreement and in turn, Epsilon will earn 60% of the land owner's available mineral interests in the approximate 15,800 gross/13,600 net acres it owns or controls.

On November 1, 2010, the Corporation entered into a joint venture agreement with Rockefeller Hughes (USA), LLC ("RHC"), a party related by common directorship, pursuant to which the Corporation agreed to assign 9% of its 60% working interest in the land owner's available mineral interests to RHC.

On September 29, 2011, Rockefeller Hughes (USA), LLC revoked its working interest back to the Corporation, in exchange for relief of July, August and September's joint interest billings.

As of September 30, 2011, Epsilon completed its first horizontal well in Mississippi targeting the brown Dense Formation. Epsilon has completed an evaluation of its horizontal well in Mississippi targeting the Brown Dense Formation. The Corporation has concluded that in order to recover commercial quantities of oil, the well will need to be stimulated. Other Industry participants have also deemed the formation as prospective, but have reached similar conclusions in terms of having to stimulate production. Given the complexity of such an operation, Epsilon is actively seeking an industry partner to assist with this stimulation and to participate in the development of this asset. Some preliminary meetings have been held with interested parties but no conclusive arrangement has been reached. Epsilon has fulfilled all current financial obligations related to this asset.

New York

In New York, where the Corporation holds an interest in approximately 15,830 gross/net acres, the Corporation's acreage is prospective for natural gas production in both the Marcellus shale, (shallow unconventional natural gas play) and the Trenton Black River formation (deep conventional natural gas play).

NY Marcellus Shale

In NY Marcellus Shale, where the Corporation holds 100% interest in the leasehold and is the operator, it continues to evaluate potential exploration, development and production opportunities in the Marcellus shale, including but not limited to, participating in competitor wells, developing its existing leasehold acreage and/or entering in joint ventures with other companies. As such, the Corporation has commenced the early stages of forming a large Marcellus shale project, including staking well locations, planning infrastructure and seeking regulatory approvals. Marcellus shale drilling permits utilizing larger hydro-fractures are currently on hold pending completion of a Supplemental Generic Environmental Impact Statement by the New York Department of Environmental Conservation. As of the date of this report the Corporation had drilled four wells in New York.

NY Trenton Black River

The Corporation has assigned most of its interests in previously held non-operated working interests with multiple operators in well units from less than 1%, up to approximately 12%, but still holds undeveloped acreage in this play.

During the first nine months of 2011, net production from Trenton Black River formation was approximately 0.1 Mmcf/d. Due to its current focus on the Marcellus shale in Pennsylvania and New York, the Corporation is not allocating a significant amount of capital to fund participation in drilling future wells targeting the Trenton Black River formation in New York.

Ohio

The Bailey's Mill project is located in Belmont and Monroe counties and consists of approximately 2,696 gross (674 net) leasehold acres, in which the Corporation holds a 25% non-operated working interest. Due to its current focus on the Marcellus shale in Pennsylvania and New York, the Corporation does not anticipate allocating a significant amount of funds to continue participating in drilling future wells on its Bailey's Mill project.

Canada

Saskatchewan

On August 28, 2008, the Corporation entered into an agreement with an unrelated public Canadian company covering joint oil and natural gas exploration and development activities in a 63,360 gross acre Area of Mutual Interest ("**AMI**") covering the Bakken oil play in southeast Saskatchewan province. The project lies within the favorable Saskatchewan province royalty area. The public Canadian company is the operator of the AMI. The Corporation agreed to pay 100% of the costs to drill a minimum of two horizontal wells in order to earn a 50% working interest in approximately 8,960 gross (7,800 net) acres controlled by the unrelated public company.

Drilling operations in the AMI commenced in August 2009. The Corporation paid $2.2 million for the cost to drill and complete the first of the two aforementioned earning wells. The second well obligation of $2.4 million was partially substituted for a 3D seismic program, which resulted in expenditures to the Corporation of $1.4 million. The remaining balance after the completion of 3D seismic program of $1.0 million was committed to the next well. As of September 30, 2011, the Corporation has fulfilled its cost obligation. The first well, the Torquay, was drilled horizontally, fractured and is currently in production. The second Torquay well was drilled, tested and a Midale discovery was made. The well has averaged 211 bbl/d for the first 30 days. Epsilon anticipates on accelerating further oil projects with its partner, and has allocated approximately $7.4 million for future operations.

On October 9, 2008, the Corporation acquired additional prospective Bakken oil play interests in approximately 31,370 gross (13,800 net) acres jointly with the same public Canadian company via a competitive bid at the Saskatchewan crown lease sale. In this acreage, the Corporation has drilled one well in Weyburn Project area, which had inconclusive results, has been

written off as of June 30, 2011. The total cost written off was $.26 million. A second well was drilled and completed in the Ceylon Project area, at a total cost of $.61 million to date. The well has averaged approximately 24 bbl/d for the first 85 days. This well produces from an un-stimulated Bakken interval. The Corporation believes much greater rates can be achieved in the project with horizontal drilling and fracture stimulation. A 3D seismic survey is currently being shot, costing the Corporation $.73 million, and once processed, will be followed by a horizontal Bakken well prior to year end.

On April 11, 2011, the Corporation further acquired prospective Bakken oil play interests in approximately 5,760 gross (2,880 net) acres for $.72 million jointly with the same public Canadian company via a competitive bid at the Saskatchewan crown lease sale.

Quebec

The Corporation has an elective participating interest of up to 25% in a portion of Gastem Inc.'s (TSXV: **GMR**) leasehold acreage in the St. Lawrence Lowlands (covering Utica shale and Trenton Black River targets) and in the Gaspe Peninsula (covering Silurian and Devonian targets). Within Gastem Inc.'s St. Lawrence Lowlands leasehold acreage, Forest Oil Corporation recently spent CDN$10.0 million to earn a 60% interest in what is now referred to as the Yamaska project. The Corporation elected not to participate on the first two exploratory wells drilled within the Yamaska project, while electing to participate in future operations with a 5% working interest.

As of September 30, 2011, the provincial government and Ministry of the Environment have been conducting a study on the environmental impact of hydraulic fracturing in Utica shale lands. This study is expected to last another 21 months. Operations are on hold in the Utica shale area until the study is complete.

Ethiopia – Northwest Area Study Agreement

On May 14, 2009, the Corporation announced that it had signed a Production Sharing Agreement ("**PSA**") with the Ministry of Mines and Energy (the "**Ministry**") in Democratic Republic of Ethiopia. The PSA covers an area of 82,500 square kilometers (31,853 square miles) in northwest Ethiopia. Terms of the PSA include an initial three-year exploration period that includes a minimum financial commitment of $3.0 million to drill one exploratory well and to acquire a minimum of 200 kilometers of 2D seismic. In the event the Corporation makes a commercial discovery, the initial percentage split of profit oil and/or gas will be 80% for the Corporation and 20% for the Ministry. To September 30, 2011, the Corporation had incurred $2.6 million under the terms of the agreement, mainly for a high resolution airborne gravity and magnetic survey.

RESULTS OF OPERATIONS

The following discussion encompasses the Corporation's revenues and costs of operations. Unless noted otherwise, the discussion pertains to the Corporation's Appalachian basin segment in the United States, as all other identified geographical operating segments were essentially in the start-up phase during the presented periods and had minimal reportable revenues or operating costs during the presented years.

Total revenues

(in thousands of dollars, except per unit and production values)	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Total Revenues	**$ 1,583**	**$ 2,690**	**$ 5,271**	**$ 10,556**
Net natural gas production (Mcfe)	312,166	620,293	1,124,535	2,153,551
Average natural gas price ($/Mcfe)	$ 4.31	$ 4.33	$ 4.40	$ 4.89
End of period net production exit rate (Mcfe/d)	1,122	6,046	1,122	6,046
Net oil production (bbls)	1,578	78	4,178	296
Average oil price ($/bbl)	$ 81.62	$ 69.92	$ 76.69	$ 81.01

Three months ended September 30, 2011 and 2010
Total revenues decreased in the third quarter of 2011, when compared to the same period in 2010, as a result of the 50 percent reduction of revenue from its existing wells due to Chesapeake reaching the $25 million capital expenditure milestone on behalf of Epsilon, effective as of March 1, 2011. Epsilon's net production also decreased due to discontinued production after August 1st in New York, and temporary well shut-ins in Pennsylvania. One well was shut-in during mid-July and remains shut in until other wells in the unit are completed. Two additional wells were shut in during a portion of September, due to frac'ing and weather conditions. There will be a substantial production increase in the last quarter of 2011, as new wells come online. Average natural gas prices in were consistent between the two periods.

Nine months ended September 30, 2011 and 2010
Total revenues decreased during the nine months ended September 30, 2011, when compared to the same period in 2010, as a result of decreased production stemming from well maintenance during the period February 22, 2011 to March 17, 2011, and as a further result of the 50 percent reduction of revenue from its existing wells due to Chesapeake reaching the $25 million capital expenditure milestone on behalf of Epsilon, effective as of March 1, 2011. Epsilon's net production also decreased due to discontinued production after August 1st in New York, and temporary well shut-ins in Pennsylvania. One well was shut-in during mid-July and remains shut in until other wells in the unit are completed. Two additional wells were shut in during a portion of September, due to frac'ing and weather conditions. There will be a substantial production increase in the last quarter of 2011, as new wells come online. Even though Epsilon's net production decreased, there has actually been an overall increase in gross production from three additional wells coming online in Pennsylvania than in the first nine months of 2010. As for average natural gas prices in 2010, the corporation sold its gas partially under hedge contracts until the end of June 2010, at a price 10.0 percent higher than in 2011.

Project Operating Costs

(in thousands of dollars)	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Project operating costs	**$ 1,187**	**$ 264**	**$ 1,736**	**$ 1,842**

Project operating costs consist of lease operating expenses necessary to extract gas and oil, including transporting it to a sales point and production taxes assessed by the state in which production occurs. These expenses vary directly with the level of oil and natural gas production and related expenses.

Three months ended September 30, 2011 and 2010
Project operating costs for the three months ended September 30, 2010 were increased by $.19 million due to a 2010 IFRS reclass of pre-acquisition costs to operating expense. For the three months ended September 30, 2011, project operating costs increased by $.92 million mainly due to a one time catch-up of $.72 in pipeline operating costs that were added in the third quarter. Operating costs will level off going forward, and correspond more directly with production trends.

Nine months ended September 30, 2011 and 2010
Project operating costs for the nine months ended September 30, 2010 were increased by $.9 million due to a 2010 IFRS reclass of pre-acquisition costs to operating expense. For the nine months ended September 30, 2011, project operating costs decreased due to decreased net production, and credit adjustments that Chesapeake flowed through to Epsilon in June, but were offset by one time catch-up of pipeline operating costs added in the period.

Depletion, depreciation, and amortization ("DD&A")

	Three months ended September 30,		Nine months ended September 30,	
(in thousands of dollars)	**2011**	**2010**	**2011**	**2010**
Depletion, depreciation and amortization	**$ 1,356**	**$ 1,130**	**$ 2,839**	**$ 3,936**

Oil and natural gas assets are depleted from the moment they are available for use on a unit-of-production basis over the proved developed reserves of the field concerned, except in the case of assets whose useful life is shorter than the lifetime of the field, in which case the straight-line method is applied. License acquisition, field development and future decommissioning costs are amortized over total proved reserves of the relevant area. Where individually insignificant, unproved properties may be grouped and amortized based on factors such as the average lease term and past experience of recognizing proved reserves.

Substantially all depreciation expense amounts pertained to the Corporation's office furniture and fixtures, computer hardware and software.

Three months ended September 30, 2011 and 2010
The depletion, depreciation and amortization ("**DD&A**") expense increased during the three months ended September 30, 2011 compared to September 30, 2010 due to a change in how the amortization base is calculated. Previously, most current year additions were excluded from the amortization base until ether the wells were producing or the following year. The calculation now includes current year additions, which increases the DD&A rate. Overall, there was a decrease in net production.

Nine months ended September 30, 2011 and 2010
The depletion, depreciation and amortization ("**DD&A**") expense had a net decrease during the nine months ended September 30, 2011 compared to September 30, 2010. The expense increased in the third quarter due to a change in how the amortization base is calculated. Previously, most current year additions were excluded from the amortization base until ether the wells were producing or the following year. The calculation now includes current year additions, which increases the DD&A rate. Overall, there was a decrease in net production.

Impairment on exploration & evaluation asset

	Three months ended September 30,		Nine months ended September 30,	
(in thousands of dollars)	2011	2010	2011	2010
Impairment on exploration & evaluation asset	**$ 397**	**$ 263**	**$ 1,455**	**$ 296**

Three months ended September 30, 2011 and 2010

During the three months ended September 30, 2011, Epsilon's undeveloped properties in Ohio was further impaired. Fifty percent of this property's net book value of $.79 million was impaired in June 30, 2011, and 25 percent was impaired during the third quarter, leaving the last 25 percent to be impaired in the fourth quarter, as leases expire. During the same period in 2010, impairments were recorded for various international projects.

Nine months ended September 30, 2011 and 2010

During the nine months ended September 30, 2011, when compared to 2010, the increase of $1.16 million was due to impairments on undeveloped properties in Ohio of $1.18 million, plus an impairment on a well drilled in the Weyburn area in Epsilon's Bakken project had an of $.26 million. During the same period in 2010, impairments were recorded for various international projects.

General and administrative

	Three months ended September 30,		Nine months ended September 30,	
(in thousands of dollars)	2011	2010	2011	2010
General and administrative	**$ 994**	**$ 268**	**$ 3,153**	**$ 3,360**

General and Administrative ("**G&A**") consists of general corporate expenses such as compensation, legal, accounting and professional fees, consulting services, travel and other related corporate costs such as stock options granted.

Three months ended September 30, 2011 and 2010

The G&A expenses had a net increase during the three months ended September 30, 2011 mainly due to a $.76 million increase in non-monetary compensation when compared to 2010. During the same period in 2010, several stock options forfeitures were reversed, creating a negative expense to non-monetary compensation. Despite the increase, there were also reductions in wages and salaries, when compared to 2010, as a result of Chesapeake becoming the operator of Epsilon's Pennsylvania properties.

Nine months ended September 30, 2011 and 2010

The G&A expenses had a net decrease during the nine months ended September 30, 2011, since in 2010, the Corporation incurred a one-time $1.0 million transaction fee on the closing of the joint venture agreement with Chesapeake. There were also reductions in wages and salaries, when compared to 2010, as a result of Chesapeake becoming the operator of Epsilon's Pennsylvania properties. Despite the decrease, there was a significant increase to executive bonuses of $.58 million for the nine months ended September 30, 2011 when compared to the same period in 2010. The executive bonus is directly correlated with the gain from disposal of farmout assets, as it is based on consolidated net income before tax. There was also an increase in non-monetary compensation when compared to 2010. During the same period in 2010, several stock options forfeitures were reversed, creating a negative expense to non-monetary compensation.

Gain on farmout agreement

	Three months ended September 30,		Nine months ended September 30,	
(in thousands of dollars)	2011	2010	2011	2010
Gain on farmout agreement	$ 3,343	$ -	$ 27,625	$ -

Three months ended September 30, 2011 and 2010

During the three months ended September 30, 2011, Chesapeake, Statoil and Epsilon executed an Interim Gas Gathering Systems agreement, where the Corporation sold an additional 15% interest in its existing gathering system. In the original Farmout Agreement, 50% of these assets were already assignable to Chesapeake, upon fulfilling the carry obligations. As part of the terms of the new agreement, Epsilon received $5.0 million to apply against the Farmout Agreement carry on the original 50% interest, and $1.5 million as consideration for the additional 15% interest. The Corporation recognized a gain on disposal on 15% of the gathering system assets for $.27 million. Additionally, and adjustment of $3.1 million was made to true-up the deferred tax liability on the Chesapeake Farmout gain.

Nine months ended September 30, 2011 and 2010

During the nine months ended September 30, 2011, Chesapeake, Epsilon's joint venture partner in Pennsylvania, fulfilled its first earning period carry obligation benchmark by spending $50.0 million in development costs on Epsilon's behalf in accordance to the executed Farmout agreement. Epsilon derecognized 25% of its assets pertaining to the Farmout agreement assignable to Chesapeake in the amount of $13.9 million, and recognized a gain on disposal of the assets for $36.1 million, less deferred tax of $8.8 million. Additionally, the Corporation received $1.5 million as consideration for assigning an additional 15% interest of its gathering system assets to Chesapeake. The Corporation recognized a gain on disposal on 15% of the gathering system assets for $.27 million.

Other income

	Three months ended September 30,		Nine months ended September 30,	
(in thousands of dollars)	2011	2010	2011	2010
Other income	$ 13	$ 28	$ 34	$ 68

Other income mainly consists of interest income or expense.

Three and nine months ended September 30, 2011 and 2010

Other income in 2011 was consistent with 2010 since Epsilon's cash balances were consistent over the two reporting periods.

Net income

(in thousands of dollars except per share amounts)	Three months ended September 30,		Nine months ended September 30,	
	2011	**2010**	**2011**	**2010**
Net income (loss)	$ 1,987	$ 790	$ 24,725	$ 1,180
Net income (loss) per share, basic	$ 0.04	$ 0.02	$ 0.50	$ 0.02
Net income (loss) per share, diluted	$ 0.04	$ 0.02	$ 0.49	$ 0.02

Three months ended September 30, 2011 and 2010

In the three months ended September 30, 2011, the Corporation had an increase in net income of $1.2 million, when compared to 2010. The increase was mainly due to credit adjustments to deferred tax expense. Excluding the deferred tax credits, the Corporation had a decrease in net income, when compared to the same period in 2010, due to lower Oil and gas revenues, higher DD&A, operating costs and G&A costs. Also, the impairments on undeveloped properties recognized were higher than in same period for 2010.

Nine months ended September 30, 2011 and 2010

Net income for the nine months ended September 30, 2011 increased substantially over 2010 due primarily to the gain of the Farmout agreement assets and deferred tax credit adjustments. Excluding the gain, there was a decrease in net income when compared to the same period in 2010. Oil and gas revenues were lower, DD&A and operating costs were higher, and recognized impairments on undeveloped properties contributed to the decrease.

SUMMARY OF QUARTERLY RESULTS

Summary quarterly information is presented in the table below. All amounts rounded to thousands of dollars, except for the number of shares and per share amounts.

(in thousands of dollars, except shares outstanding and per share amounts)	Dec 31, 2009 $	Mar 31, 2010 $	June 30, 2010 $	Sep 30, 2010 $	Dec 31, 2010 $	Mar 31, 2011 $	Jun 30, 2011 $	Sep 30, 2011 $
Revenues:								
Gas	2,374	3,983	3,864	2,685	4,191	1,820	1,676	1,454
Oil	19	13	6	5	7	192	0	129
Total revenues	2,393	3,996	3,870	2,690	4,198	2,012	1,676	1,583
Operating costs	300	522	792	200	661	436	113	1187
Impairment of unproved properties	16,031	33	-	263	-	-	1,057	397
Exploration and evaluation costs	-	-	263	65	-	-	-	-
DD&A	937	1,483	1,323	1,130	803	832	650	1,356
Asset accretion expense	-	6	2	2	63	3	3	1
G&A	770	1,960	1,132	268	769	713	1446	994
Cost of operations	18,038	4,004	3,512	1,928	2,296	1,984	3,269	3,936
Operating income (loss)	(15,645)	(8)	358	762	1,902	28	(1,593)	(2,353)
Gain (loss) on sale of assets	12,493	-	-	3	(38)	(2)	24,282	3,343
Other income (loss)	16	18	22	25	23	13	10	13
Net income (loss) before income taxes	(3,136)	10	380	790	1,887	39	22,699	1,003
Income tax expense (recovery)	(2,600)	-	-	-	-	-	-	(984)
Net income (loss)	(5,736)	10	380	790	1,887	39	22,699	1,987
Weighted average number of shares outstanding, basic	50,325,998	50,550,998	49,840,185	49,722,672	49,725,179	49,716,252	49,716,252	49,815,816
Weighted average number of shares outstanding, diluted	50,325,998	50,550,998	51,175,431	50,719,276	49,800,170	51,626,743	50,403,463	50,332,149
Net income (loss) per share, basic	(0.11)	0.00	0.01	0.02	0.04	0.00	0.46	0.04
Net income (loss) per share, diluted	(0.11)	0.00	0.01	0.02	0.04	0.00	0.45	0.04

LIQUIDITY AND CAPITAL RESOURCES

Working Capital

At September 30, 2011, the Corporation had a working capital surplus (inclusive of restricted cash) of $18.2 million, as compared to $20.3 million of surplus working capital (inclusive of restricted cash) at December 31, 2010. The net decrease is a result of planned drilling operational costs spent towards Epsilon's Mississippi project, offset by cash received in consideration for a share in the Corporation's gathering system.

As of September 30, 2011, Epsilon is debt free. It is expected that cash on hand and cash flow from the sale of natural gas as part of the farmout agreement with Chesapeake should be sufficient to fund the Corporation's exploration plans, particularly in the Marcellus shale project and other projects in the US, Canada and Africa.

Cash Flow from Operating Activities

Three months ended September 30, 2011 and 2010
During the three months ended September 30, 2011, $0.2 million was used in the Corporation's operating activities, compared to $1.7 million provided for during the same period in 2010, primarily due to the reduction in revenues as explained above.

Nine months ended September 30, 2011 and 2010
During the first nine months of 2011, $0.2 million was provided by the Corporation's operating activities, compared to $5.4 million in the first nine months of 2010, primarily due to the reduction in revenues as explained above.

Cash Flow from Investing Activities

Three months ended September 30, 2011 and 2010
During the three months ended September 30, 2011, $3.3 million was provided by the Corporation's operating activities, compared to $.1 million provided for during the same period in 2010. Epsilon had additional proceeds $6.5 million related to the Chesapeake Interim gas gathering agreement, which was offset by $3.2 million net cash outflow, mainly related to drilling expenditures in Saskatchewan and Mississippi. Drilling costs for the same period in 2010 were minimal.

Nine months ended September 30, 2011 and 2010
During the first nine months of 2011, there was a net cash outflow of $.4 million. Epsilon had additional proceeds $6.5 million related to the Chesapeake Interim gas gathering agreement, which was offset by $6.9 million net cash outflow, mainly related to drilling expenditures in Saskatchewan and Mississippi. When compared to 2010, a net cash outflow of $1.4 million related to the Chesapeake farmout agreement of $5.0 million, which was offset by an outflow of $6.4 million on drilling costs in New York.

Cash Flow from Financing Activities

Three months ended September 30, 2011 and 2010
During the three months ended September 30, 2011, $.09 million net cash was provided for, which consisted of proceeds from an option exercise, offset by a common share buyback. For the same period in 2010, $.10 million net was provided for, primarily for option exercises.

Nine months ended September 30, 2011 and 2010
During the first nine months in 2011, $.09 million net cash was provided for, which consisted of proceeds from an option exercise, offset by a common share buyback. For the same period in 2010, there was $2.1 million net cash used, primarily for a common share buyback, offset by option exercises.

OUTSTANDING SHARE CAPITAL

The following table summarizes the development of share capital from December 31, 2009 to September 30, 2011:

(in thousands of dollars, except for the number of shares)	Number of Shares Issued	Amount
Balance at December 31, 2009	50,325,998	$ 138,272
Buy back of shares	(1,125,000)	(3,068)
Exercise of stock options	515,254	797
Balance at December 31, 2010, and June 30, 2011	49,716,252	$ 136,001
Buy back of shares	(64,300)	(184)
Exercise of stock options	130,000	399
Balance at September 30, 2011	49,781,952	$ 136,216

Stock options

The weighted average fair value of options granted during the nine months ended September 30, 2011 was $3.58 (September 2010: $2.84) per option calculated using a risk-free rate of 4.3%, dividend yield of 0%, historical volatility factor of 100%, and expected life ranging from .1 to 9.6 years. The value of the options was recorded as stock based compensation expense, with an offsetting amount to contributed surplus based on the vesting terms.

On May 12, 2011, the Corporation awarded 46,740 to directors and 675,000 options to employees in accordance with Epsilon's Stock Option Plan. These stock options are exercisable at the closing price of $3.61 on May 12, 2011. The directors' options will vest immediately. The employees' options will vest only after the common shares trade at or above $8.00 per share on the Toronto Stock Exchange for a period of 20 consecutive trading days at any time in the 36 months from the date of grant of the options.

As of September 30, the May 12, 2011 option grants were re-valued under the Trinomial Hull White pricing model, creating an additional expense of $.04 million for the period. The Hull White model handles performance and market based vesting criteria more appropriately than the Black Scholes model.

Intangible exploration and evaluation assets

(in thousands of dollars)	September 30 2011	December 31 2010
Intangible exploration and evaluation assets	**$ 32,928**	**$ 41,283**

The intangible exploration and evaluation assets decreased by $8.4 million as a net result of additions during the normal course of operations of $20.8 million, offset by a transfer of $27.7 million proved property costs to property & equipment and impairments to unproved property for $1.4 million. Of those assets, $10.7 million in additions and $18.4 million in transfers were related to the Chesapeake farmout assets.

Net property and equipment

(in thousands of dollars)	September 30 2011	December 31 2010
Net property and equipment	$ 86,809	$ 42,627

The net increase of $44.2 million in property and equipment in 2011 is due to $33.8 million additional expenditures relating to the Chesapeake farmout assets, $27.7 million of incoming transferred cost from exploration & evaluation assets, offset by a decrease of $15.1 million, due to the first 25% disposal on Epsilon's farmout assets in Pennsylvania, the 15% additional disposal on Epsilon's gas gathering assets, and a decrease of $2.8 million for depletion, amortization & impairment.

Reportable Geographical Operating Segments

As at September 30, 2011, the Corporation's operations by geographical area included the United States, Canada and Ethiopia. Summarized reportable geographical segment data follows:

(in thousands of dollars)

	Three months ended September 30,		Nine months ended September 30,	
Reportable Segments:	**2011**	**2010**	**2011**	**2010**
United States:				
Revenues	$ 1,466	$ 2,685	$ 4,962	$ 10,533
Operating costs	1,129	262	1,573	1,838
Capital expenditures	14,362	4,599	20,012	11,951
Canada:				
Revenues	118	5	309	23
Operating costs	59	2	163	4
Capital expenditures	729	114	2,924	1,509
Ethiopia:				
Revenues	-	-	-	-
Operating costs	-	-	-	-
Capital expenditures	13	78	212	257
Other International:				
Revenues	-	-	-	-
Operating costs	-	-	-	-
Capital expenditures	-	1	-	16
Total Reportable Segments				
Revenues	**$ 1,584**	**$ 2,690**	**$ 5,271**	**$ 10,556**
Operating costs	**$ 1,188**	**$ 264**	**$ 1,736**	**$ 1,842**
Capital expenditures	**$ 15,104**	**$ 4,792**	**$ 23,148**	**$ 13,733**

The numbers above exclude asset sales and impairments.

COMMITMENTS AND CONTINGENCIES

New York –Trenton Black River Well Units

During 2006, the Department of Environmental Conservation ("DEC") classified the Corporation's interest in several wells drilled prior to a statute change as an integrated non-participating owner. As a result, the Corporation was charged a non-consent penalty (300% of 100% of the total drilling and completion costs) on its pro-rata share of costs to drill and complete various wells by Talisman Energy Inc. (formerly Fortuna Energy Inc.), the operator. The Corporation believes its interest in the subject wells should have been classified as an integrated participating owner upon payment of its pro-rata share of costs, effectively negating the non-consent penalty the operator could charge prior to disbursing the Corporation's pro-rata share of profits. The Corporation formally appealed the DEC's ruling, and, if successful, will require the non-consent penalty withheld by the operator to be disbursed to the Corporation. As a result, there is no anticipated effect on the Corporation's established working interest. As a non-operator, the Corporation is not liable to make any non-consent payments.

Due to this contingency, there were no amounts initially recorded on the Corporation's consolidated financial statements prior to payout. In the case where payout has occurred, the Corporation recorded its share of costs and revenues on a prospective basis beginning with the month that each well had been determined to have achieved payout. As at September 30, 2011, the Corporation was classified as an integrated non-participating owner in 1 gross (0.03 net) wells. In 2011, the Corporation received a favorable decision on its Drumm well appeal from the NY DEC commissioner. The decision was not appealed by Talisman Energy Inc. (formerly Fortuna Energy Inc.) and the Corporation is currently awaiting final settlement numbers. This decision will result in reimbursement of the non-consent penalty charged to the Corporation for that well. There has been no decision issued for the remaining wells that the Corporation has appealed. All remaining previously mentioned wells have been assigned to the Corporation's former partners.

Mississippi

On October 1, 2010, the Corporation signed Participation Agreement (the "Agreement") with a large US-based private land owner ("land owner") to explore for and produce oil and gas. Under the principal terms of the Agreement, Epsilon is committed to drill a minimum of two horizontal wells within one year from the effective date of the agreement at an estimated cost of $10.0 million and, in turn, Epsilon will earn 60% of the land owner's available mineral interests in the approximate 15,800 gross/13,600 net acres it owns or controls. Should the Corporation fail to drill the two wells within the time period specified, the Corporation will pay a sum of $1.0 million within ten days after the end of the time period. On November 1, 2010, the Corporation entered into a joint venture agreement with Rockefeller Hughes (USA), LLC ("RHC"), a party related by common directorship, pursuant to which the Corporation agreed to assign 9% of its 60% working interest in the land owner's available mineral interests to RHC. Since Epsilon and RHC are carrying the cost of the first two wells, the Epsilon's proportionate share of the commitment has become $8.5 million. As of September 30, 2011, Epsilon spent $4.9 million on the first well of its two well commitment.

The second well of the two well commitment was not drilled by August 31, 2011, so the Corporation incurred a penalty fee of $1.0 million, which was paid in October. Also, on September 29, 2011, Rockefeller Hughes (USA), LLC revoked its working interest back to the Corporation, in exchange for relief of July, August and September's joint interest billings. Epsilon is actively looking for a joint venture partner to continue operations in this area

Ethiopia

On May 14, 2009, the Corporation announced that it had signed a Production Sharing Agreement ("PSA") with the Ministry of Mines and Energy in Democratic Republic of Ethiopia (the "Ministry"). Terms of the PSA comprise of an initial three-year exploration period that includes a commitment to drill one exploratory well and to acquire a minimum of 200 kilometers of 2D seismic. The Corporation is also committed to make three annual payments $.04 million each for training and community development, three annual payments of $.083 million for land rentals and a work commitment of $3.0 million to be spent by the end of the PSA term.

In the event the Corporation makes a commercial discovery, the initial percentage split of profit oil and/or gas will be 80% for the Corporation and 20% for the Ministry. To September 30, 2011, the Corporation had incurred $2.60 million (2010: $2.39 million) under the terms of this agreement mainly for a high resolution airborne gravity and magnetic survey.

The Corporation's future commitments are summarized in the following table:

(in thousands of dollars)

	Payments Due by Period		
	Total	**Less than 1 Year**	**1 – 3 Years**
Future Commitments:			
Accounts payable and accrued liabilities	$ 1,678	$ 1,678	$ -
Operating leases	175	78	97
Other obligations - International	400	400	-
Total future commitments	$ 2,253	$ 2,156	$ 97

The Corporation enters into commitments for capital expenditures in advance of the expenditures being made. At a given point in time, it is estimated that the Company has committed to capital expenditures equal to approximately one quarter of its capital budget by means of giving the necessary authorizations to incur the expenditures in a future period. This commitment has not been included in the commitment table above as it is of a routine nature and is part of normal course of operations for active oil and gas companies.

Litigation

The Corporation is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that any pending litigation is without merit and would not have a material impact on the Corporation's financial position or results of operations.

ACCOUNTING POLICIES AND ESTIMATES

Adoption of International Financial Reporting Standards

The Corporation has prepared its September 30, 2011 interim unaudited condensed consolidated financial statements in accordance with IFRS 1, *First-time Adoption of International Financial Reporting Standards*, and with IAS 34, *Interim Financial Reporting*, as issued by the IASB. Previously, the Corporation prepared its financial statements in accordance with Canadian GAAP. The adoption of IFRS has not had a material impact on the Corporation's operations, strategic decisions, cash flows or capital expenditures.

The Corporation's IFRS accounting policies are provided in Note 3 to the interim unaudited condensed consolidated financial statements. In addition, Note 5 to the interim unaudited condensed consolidated financial statements presents reconciliations between the Corporation's 2010 GAAP results and the 2010 IFRS results. The reconciliations include the consolidated balance sheets as at January 1, 2010, September 30, 2010 and December 31, 2010, and consolidated statements of earnings, comprehensive income, changes in shareholders' equity and cash flows for the three and nine months ended September 30, 2010 and for the twelve months ended December 31, 2010.

The following provides summary reconciliations of Epsilon's 2010 GAAP and IFRS results, along with a discussion of the significant IFRS accounting policy changes:

(in thousands of dollars)

Summary Net Earnings Reconciliation

	2010				
	Q1	Q2	Q3	Q4	2010
Net earnings - GAAP	$ 50	$ 990	$ 983	$ 2,004	$ 4,027
Additions (deductions):					
Project operating costs	(95)	(352)	(124)	(118)	(689)
Exploration and evaluation costs	-	(263)	(65)	-	(328)
Depletion, depreciation and accretion	62	31	21	(3)	111
Asset retirement accretion	(6)	-	-	4	(2)
General and administrative	-	(27)	(25)	-	(52)
Net earnings - IFRS	**$ 11**	**$ 379**	**$ 790**	**$ 1,887**	**$ 3,067**

Financial Metrics

	2010				
	Q1	Q2	Q3	Q4	2010
Cash Flows from Operations					
GAAP	$ 1,608	$ 2,853	$ 2,717	$ 1,969	$ 9,147
IFRS	1,513	2,211	2,503	1,851	8,078

Accounting Policy Changes

The following discussion explains the significant differences between Epsilon's GAAP accounting policies and those applied by the Corporation under IFRS. IFRS policies have been retrospectively and consistently applied except where specific IFRS 1 optional and mandatory exemptions permitted an alternative treatment upon transition to IFRS for first-time adopters.

Canadian GAAP differs in certain respects from IFRS and comparative information as at January 1, 2010, as at and for the three and nine months ended September 30, 2010, and as at and for the twelve months ended December 31, 2010, has been restated as necessary in accordance with IFRS. Reconciliations of the effect of the transition from Canadian GAAP to IFRS are provided in Note 5 to the interim unaudited condensed consolidated financial statements. The descriptions of the effect of the transition from Canadian GAAP to IFRS on equity and income are given below, including a description of the nature of the changes in accounting policies. As part of Epsilon's adoption of IFRS, the following elections were made under IFRS 1 "First-time Adoption of International Financial Reporting Standards" as at January 1, 2010:

(a) IAS 21 was applied prospectively to eliminate cumulative currency translation differences by transfer to deficit.

(b) Business combinations prior to transition date have not been restated.

(c) Net property and equipment were recorded at historical cost using the oil and gas deemed cost exemption.

The remaining IFRS 1 exemptions were not applicable or material to the preparation of Epsilon's consolidated balance sheet at the date of transition to IFRS on January 1, 2010.

Accounting for Oil and Natural Gas Interests

The most significant changes to the Corporation's accounting policies relate to the accounting for oil and natural gas interests. Under GAAP, Epsilon followed the Canadian Institute of Chartered Accountants ("CICA") guideline on full cost accounting in which all costs directly associated with the acquisition of, the exploration for, and the development of oil and natural gas reserves were capitalized on a country-by-country cost centre basis. Costs accumulated within each country cost centre were depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs. Upon transition to IFRS, Epsilon was required to adopt new accounting policies, including exploration and evaluation costs and development costs. Under IFRS, exploration and evaluation costs are those expenditures for an area where technical feasibility and commercial viability has not yet been determined. Development costs include those expenditures for areas where technical feasibility and commercial viability has been determined. Epsilon applied the IFRS 1 exemption whereby the Corporation deemed its January 1, 2010 IFRS oil and natural gas interests to be equal to its GAAP historical property and equipment net book value. Accordingly, exploration and evaluation costs were deemed equal to the unproved properties balance and the development costs were deemed equal to the full cost pool balance. Under IFRS, exploration and evaluation costs are presented as exploration and evaluation assets and development costs are presented within property and equipment on the consolidated balance sheets.

(a) Exploration and evaluation assets

Exploration and evaluation assets at January 1, 2010 were deemed to be $20.1 million including $16.7 million in the US, $1.0 million in Canada, $2.3 million in Ethiopia and the Middle East, representing the unproved properties balance under previous GAAP. This resulted in a reclassification of $20.1 million from property, plant and equipment to exploration and evaluation assets on Epsilon's consolidated balance sheet as at January 1, 2010.

As at December 31, 2010, the Corporation's exploration and evaluation assets were $41.3 million including $35.3 million in the US, $3.6 million in Canada and $2.4 million in Ethiopia. The exploration and evaluation assets in the Middle East in the amount of $0.25 million were written off during the twelve months ended December 31, 2010.

Under previous GAAP, exploration and evaluation costs were capitalized as property and equipment in accordance with the CICA's full cost accounting guidelines. Under IFRS, Epsilon capitalizes these costs initially as exploration and evaluation assets. Once technical feasibility and commercial viability of the area has been determined, the capitalized costs are transferred from exploration and evaluation assets to property and equipment. Under IFRS, unrecoverable exploration and evaluation costs associated with an area and costs incurred prior to obtaining the legal rights to explore are expensed.

During the three and nine months ended September 30, 2010, and twelve months ended December 31, 2010, Epsilon transferred $nil of capitalized exploration and evaluation costs to property and equipment. During the same periods Epsilon expensed $.063, $.33 and $.33 million of previously capitalized pre-acquisition costs and $.025, $.052 and $.052 million previously capitalized salaries incurred prior to obtaining legal title to explore. The application of IFRS to exploration and evaluation costs resulted in a decrease of $.089, $.38 and $.38 million to Epsilon's Canadian GAAP net earnings for the three and nine months ended September 30, 2010 and December 31, 2010, respectively.

As at the date of transition, the Corporation tested all of its CGUs for impairment. The recoverable amount of each CGU was estimated based on the higher of the value in use and the fair value less costs to sell. The fair value less costs to sell was determined using discounted proved forecasted cash flows, with escalating prices and future development costs, as obtained from the Corporation's reserve report. Based on the above assessment, there were no adjustments to the carrying amounts of exploration and evaluation assets at January 1, 2010.

(b) Depletion, depreciation and amortization ("DD&A")

Net development costs at January 1, 2010 were deemed to be $46.6 million, representing the full cost pool balance under Canadian GAAP. Consistent with Canadian GAAP, these costs are capitalized as property and equipment under IFRS. Under

Canadian GAAP, development costs, whose life is equal to the lifetime of the field, were depleted using the unit-of-production method calculated at the established area level consistent with IFRS, with $nil effect on the DD&A expense and net earnings for the twelve months ended December 31, 2010.
The development costs whose useful life is shorter than the lifetime of the field were depreciated using a straight – line basis over the remaining useful life of the assets. The application of IFRS to development costs resulted in an increase of $.021, $.114 and $.11 million to Epsilon's Canadian GAAP net earnings for the three and nine months ended September 30, 2010 and December 31, 2010, respectively.

The IFRS 1 exemption permitted the Corporation to allocate development costs to the area level using proved reserves values for each cash generating unit as at January 1, 2010.

(c) Asset retirement obligation ("ARO")

Under Canadian GAAP, the asset retirement obligation was measured as the estimated fair value of the decommissioning liabilities expected to be incurred. Liabilities were not remeasured to reflect period end discount rates.

Under IFRS, the decommissioning liability is measured as the best estimate of the expenditure to be incurred and requires that the asset retirement obligation be remeasured using the period-end risk free discount rate.

Epsilon was required to remeasure its asset retirement obligation upon transition to IFRS and recognize the difference in retained earnings. The application of this exemption resulted in a $.006 million increase to the asset retirement obligation on Epsilon's consolidated balance sheet as at January 1, 2010, and an after-tax offset to retained earnings of $.006 million. Subsequent IFRS remeasurements of the obligation are recorded through property and equipment with an offsetting adjustment to the asset retirement obligation. As at September 30, 2010 and December 31, 2010, Epsilon's asset retirement obligation increased by $.067 and $.098 million, respectively, which primarily reflects the remeasurement of the obligation using Epsilon's risk free discount rate of 3.52 percent as at September 30, 2010 and 3.56 percent at December 31, 2010. The increase to asset retirement accretion at September 30, 2010 and December 31, 2010 was immaterial.

(d) Foreign currency translation adjustment

As permitted by IFRS 1, the Corporation elected to apply the exemption to set the cumulative foreign currency translation adjustment to zero upon transition to IFRS. Accordingly, $6.9 million was recognized as an adjustment to deficit on January 1, 2010.The reclassification had no impact on total shareholders' equity as at January 1, 2010. As a result of the election, the accounts of the Corporation have not been retrospectively restated using IFRS foreign currency principles.

The IFRS adjustments discussed above are recorded in the Corporation's functional currency and are subject to translation for presentation purposes. The associated foreign currency impacts are reported in accumulated other comprehensive income.

Recent Pronouncements Issued

All accounting standards effective for periods beginning on or after January 1, 2011 have been adopted as part of the transition to IFRS. Epsilon has reviewed new and revised accounting pronouncements that have been issued but are not yet effective and determined that the following may have an impact on the Corporation:

As of January 1, 2015, Epsilon will be required to adopt IFRS 9 "Financial Instruments", which is the result of the first phase of the International Accounting Standards Board ("IASB") project to replace IAS 39 "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. Portions of the standard remain in development and the full impact of the standard on Epsilon's Consolidated Financial Statements will not be known until the project is complete.

In May 2011, the IASB released the following new standards: IFRS 10, "Consolidated Financial Statements", IFRS 11, "Joint Arrangements", IFRS 12, "Disclosures of interests in other entities" and IFRS 13, "Fair Value Measurement". Each of these standards is to be adopted for fiscal years beginning January 1, 2013 with earlier adoption permitted. A brief description of each new standard follows below:

- IFRS 10, "Consolidated Financial Statements" supersedes IAS 27 "Consolidation and Separate Financial Statements" and SIC-12 "Consolidation – Special Purpose Entities". This standard provides a single model to be applied in control analysis for all investees including special purpose entities.

- IFRS 11, "Joint Arrangements" divides joint arrangements into two types, joint operations and joint ventures, each with their own accounting model. All joint arrangements are required to be reassessed on transition to IFRS 11 to determine their type to apply the appropriate accounting.

- IFRS 12, "Disclosure of Interests in Other Entities" combines in a single standard the disclosure requirements for subsidiaries, associates and joint arrangements as well as unconsolidated structured entities.

- IFRS 13, "Fair Value Measurement" defines fair value, establishes a framework for measuring fair value and sets out disclosure requirements for fair value measurements. This standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Epsilon is currently analysing the expected impact, if any, that the adoption of each of these standards will have on its Consolidated Financial Statements.

CRITICAL ACCOUNTING ESTIMATES

In the application of the Corporation's accounting policies, which are described in Note 3 to the interim unaudited condensed consolidated financial statements, management is required to make judgments, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the interim unaudited condensed consolidated financial statements and reported amounts of revenues and expenses during the period. Accordingly, actual results may differ from estimated results.

While management believes that its estimates have been reasonable in the circumstances, the volatility in the price of oil and natural gas, the recession in Canada and the slowdown of economic growth in the rest of the world have created a substantially more volatile business environment. These conditions will limit certain of the Corporation's previously planned business development activities and they will continue to present future risks. To prepare these interim unaudited condensed consolidated financial statements, management has recorded adjustments and included disclosures based on their best estimates of projected business activity and future cash flows.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

(a) Estimation of reserves

Engineering estimates of the Corporation's oil and natural gas reserves are inherently uncertain. Proved reserves are the estimated volumes of crude oil, natural gas and gas condensates, liquids and associated substances which geological and engineering data demonstrate that can be economically producible with reasonable certainty from known reservoirs under existing economic conditions and operating methods. Although there are authoritative guidelines regarding the engineering criteria that must be met before estimated oil and natural gas reserves can be designated as "proved", the accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Field reserves will only be categorized as proved when all the criteria for attribution of proved status have been met. At this stage, all booked reserves will be classified as proved undeveloped. Volumes will subsequently be reclassified from proved undeveloped to proved developed as a consequence of development activity. The first proved developed bookings will occur at the point of first oil or natural gas production. Epsilon reassesses its estimate of proved reserves periodically. The estimated proved reserves of oil and natural gas may be subject to future revision and upward and downward revision may be made to the initial booking of reserves due to production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity. In particular, changes in oil and natural gas prices could impact the amount of Epsilon's proved reserves in regards to the initial estimate and, in the case of production-sharing agreements and buy-back contracts, the share of production and reserves to which Epsilon is entitled. Accordingly, the estimated reserves could be materially different from the quantities of oil and natural gas that ultimately will be recovered. Oil and natural gas reserves have a direct impact on certain amounts reported in the consolidated financial statements. Estimated proved reserves are used in determining depletion, depreciation and amortization expenses and impairment expense. Depletion rates on oil and natural gas assets using the unit-of-production basis are determined from the ratio between the amount of hydrocarbons extracted in the quarter and proved developed reserves existing at the end of the quarter increased by the amounts extracted during the quarter. Assuming all other variables are held constant, an increase in estimated proved developed reserves for each field decreases depletion, depreciation, and amortization expense. Conversely, a decrease in estimated proved developed reserves increases depletion, depreciation, and amortization expense. In addition, estimated proved reserves are used to calculate future cash flows from oil and natural gas properties, which serve as an indicator in determining whether or not property impairment is to be carried out. The larger the volume of estimated reserves, the lower the likelihood of asset impairment.

(b) Impairments

The estimated future level of production is based on assumptions concerning: future commodity prices, lifting and development costs, field decline rates, market demand and supply, economic regulatory climates and other factors. Oil, natural gas and petroleum product prices used to quantify the expected future cash flows are estimated based on forward prices prevailing in the marketplace for the first year and management's long-term planning assumptions thereafter. The estimate of the future amount of production is based on assumptions related to the commodity future prices, lifting and development costs, market demand and other factors. The discount rate reflects the current market valuation of the time value of money and of the specific risks of the asset not reflected in the estimate of the future cash flows.

Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation and technology improvements on operating expenses, production profiles and the outlook for global or regional market supply and demand conditions for crude oil, natural gas, commodity chemicals and refined products.

(c) Depletion, depreciation and amortization

The amounts recorded for depletion, depreciation and amortization of petroleum and natural gas properties and equipment, the liability for retirement obligations and the amount recorded for deferred income taxes are based on estimates. The impairment test is based on estimates of proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, estimates of reserves and the related future cash flows are subject to measurement uncertainty and the impact of differences between actual and estimated amounts on the consolidated financial statements of future periods could be material.

(d) Decommissioning liabilities

The calculation of decommissioning liabilities includes estimates of the future costs to settle the obligation, the timing of the settlement of the obligation and the future interest rates. The impact of differences between actual and estimated costs, timing and inflation on the consolidated financial statements of future periods could be material.

(e) Future revenues and operating costs

Due to the volatile nature of oil and natural gas exploration, development, and production activities, there are numerous uncertainties with respect to projecting future revenues and operating costs, which are integral components of future net income projections. These uncertainties include such items as production levels, capital expenditure levels, oil and natural gas commodity prices, reserve estimates, and lease operating costs.

(f) Identification of cash-generating units ("CGU's")

Management reviews the CGU determination on a periodic basis. The recoverability of property and equipment carrying values are assessed at the CGU level. Determination of what constitutes a CGU is subject to management judgments. The asset composition of a CGU can directly impact the recoverability of the assets within.

Epsilon's other estimates include:

- Estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- Estimated capital expenditures on projects that are in progress;
- Estimated deferred income tax assets and liabilities for estimated tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis; and
- Estimated valuation allowance to reduce income tax assets, if it is more likely than not that all or some portions of such tax assets will not be realized.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Management is responsible for establishing and maintaining adequate ICFR. ICFR means a process designed by or under the supervision of the Chief Executive Officer and Chief Financial Officer, and effected by the Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with IFRS.

Disclosure controls and procedures are designed to provide reasonable assurance that material information is gathered and reported to senior management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to permit timely decisions regarding public disclosure. The Corporation has evaluated the effectiveness of its disclosure controls and procedures and has concluded based on this evaluation that the disclosure controls and procedures are effective for the period ended September 30, 2011.

Management completed an assessment of the design of ICFR. The Corporation used the Committee of Sponsoring Organizations of the Treadway Commission ("**COSO**") framework and guidance for smaller public companies for the design of the Corporation's ICFR. All internal control systems have inherent limitations and therefore our ICFR can only provide reasonable assurance and may not prevent or detect misstatements due to error or fraud.

Environmental Issues

Compliance with Environmental and Safety Regulations

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills and releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liabilities, and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Corporation's financial condition, results of operations or prospects. The Corporation must also conduct its operations in accordance with various laws and regulations concerning occupational safety and health. Currently, the Corporation does not foresee expending material amounts to comply with occupational safety and health laws and regulations. However, since such laws and regulations are frequently changed, the Corporation is unable to predict the future effect of these laws and regulations.

The Corporation's activities are subject to numerous federal, provincial and state laws and regulations concerning the storage, use and discharge of materials into the environment, the remediation of environmental impacts and other matters relating to environmental protection, all of which may adversely affect the Corporation's operations and the costs of doing business. Federal, provincial and state regulatory authorities also have established rules and regulations requiring permits for drilling, drilling bonds and reports concerning drilling and producing activities. Such regulations also cover the location of wells, the method of drilling and casing wells, the surface use and restoration of well locations, the plugging and abandoning of wells, and other matters. There can be no assurance that future legislation or administrative regulations or interpretations will not impose stricter requirements that could have an adverse impact on the operating costs of the Corporation and the oil and natural gas industry in general. The Corporation believes it is in material compliance with existing environmental laws and regulations and does not currently believe that it will be required to expend material amounts to comply with existing environmental laws and regulations in the future.

OFF-BALANCE SHEET ARRANGEMENTS

The Corporation has no off-balance sheet arrangements.

TRANSACTIONS WITH RELATED PARTIES
The Corporation reports its related party transactions on an exchange amount basis in equivalent US dollars. A summary of such transactions follows:

Executive Chairman
The Corporation utilizes administrative services provided by 706147 Ontario, Inc., a company owned by the Executive Chairman's spouse. The Corporation utilizes consultation services provided by Capital Z Corporation, a company owned by the Executive Chairman and the Corporation shares office space with Capital Z Corporation at no charge. The Executive Chairman is the Chairman and CEO of Rockefeller Hughes, a company that rents office space from the Corporation. The following general and administrative transactions arose in the normal course of business and have been accounted for at the exchange amount being the amount agreed to by the related parties, which approximates the arms length equivalent value:

(in thousands of dollars)

	Three months ended September 30,		Nine months ended September 30,	
	2011	**2010**	**2011**	**2010**
706147 Ontario, Inc.	$ 11	$ 10	$ 33	$ 31
Capital Z Corporation	20	2	39	39
Rockefeller Hughes	(5)	(3)	(14)	(13)

The following balances are included in accounts payable and accrued liabilities and are unsecured, non-interest bearing and due on demand:

(in thousands of dollars)

	Nine months September 30, 2011	**December 31, 2010**	**January 1, 2010**
706147 Ontario, Inc.	$ 4	$ -	$ 49
Capital Z Corporation	4	1	2

The following balances are included in accounts receivable and are unsecured, non-interest bearing and due on demand:

(in thousands of dollars)

	Nine months September 30, 2011	**December 31, 2010**	**January 1, 2010**
Rockefeller Hughes	$ -	$ -	$ -

On September 29, 2011, Rockefeller Hughes revoked its 15% working interest back to the Corporation, in exchange for relief of July, August and September's joint interest billings of $.45 million.

Director
On February 7, 2007, the Corporation obtained a 25% undivided participating interest in Gastem Inc.'s undeveloped oil and natural gas interests covering approximately 1,184,000 acres (249,000 net) in the St. Lawrence Lowlands and in the Gaspe Peninsula of Quebec. Under terms of the agreement, the Corporation may elect to participate on a well-by-well basis with a 25% working interest in any current or future oil and natural gas property Gastem Inc. may acquire in Quebec. In return, the Corporation granted Gastem Inc. the right to participate for 25% of the Corporation's interest in certain future wells to be drilled in the Corporation's Amber Bank project in West Virginia by spending up to $1.05 million. The Corporation's carrying value of the portion of its Amber Bank project's leasehold attributable to Gastem Inc.'s participation was nominal. The agreement was consummated with the expectation that Raymond Savoie, Gastem Inc.'s President, would become a director of the Corporation. Mr. Savoie became a director of the Corporation on July 16, 2007. On June 16, 2009, the Corporation, along with Gastem Inc., sold all of its oil and natural gas property interests in West Virginia to an unrelated third party for a gross amount of $14,000,000 ($779,802 net to Gastem Inc.). A summary of Gastem's joint venture share of related party transactions between the Corporation and Gastem Inc. follows:

(in thousands of dollars)

	Three months ended September 30,		Nine months ended September 30,	
	2011	**2010**	**2011**	**2010**
Gastem Inc.				
Joint venture costs	$ (70)	$ 17	$ (12)	$ 93

	Nine months September 30, 2011	December 31, 2010	January 1, 2010
Accounts payable	$ 25	$ 151	$ 297

Cash remuneration of key management personnel of the Corporation, which includes officers and other key personnel, is set out below in aggregate:

	Three months ended September 30,		Nine months ended September 30,	
	2011	**2010**	**2011**	**2010**
Salaries and wages	$ 235	$ 267	$ 758	$ 632
Short-term benefits	2	2	5	5
Total compensation	$ 237	$ 269	$ 763	$ 637

These transactions arose in the normal course of business and have been accounted for at the exchange amount being the amount agreed to by the related parties, which approximates the arms length equivalent. The balances are unsecured, non-interest bearing and due on demand.

Additional Information:
Additional information relating to the Corporation can be found on SEDAR at www.sedar.com

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