International Frontier Resources Corporation
Management's Discussion and Analysis
2010 Annual and Fourth Quarter Results

International Frontier Resources Corporation is engaged in the exploration for and development of petroleum and natural gas reserves in the Central Mackenzie Valley ("CMV"), Northwest Territories, Canada and in southern Alberta.

The following is management's discussion and analysis ("MD&A") of International Frontier Resources Corporation's ("International Frontier" or "IFR" or the "Corporation" or the "Company") operating and financial results for the year ended December 31, 2010, as well as information concerning the Company's future outlook based on currently available information. The MD&A has been prepared by management as at April 13, 2011 in accordance with GAAP and should be read in conjunction with the audited consolidated financial statements as at December 31, 2010 and 2009 together with accompanying notes, the Statement of Reserves Data and Other Oil and Gas Information contained in the Company's annual information form dated December 31, 2010. This MD&A contains forward looking statements, the definitions of which are defined herein.

The MD&A and the annual consolidated financial statements and accompanying notes have been prepared by management and approved by the Audit Committee and the Board of Directors.

The quarterly financial statements have not been reviewed or audited on behalf of the shareholders by the Company's independent external auditors. All financial measures presented in this MD&A Report are expressed in Canadian dollars unless otherwise indicated.

Operations Review

This report provides a review of operations for the period January 1, 2010 to March 31, 2011.

First Quarter

In Q1 the company participated with the Bowmore partners in the pooling of North Sea block 15/23c with Nexen et al block 15/23d. The pooling allowed the Bowmore partners to fulfill its two well drilling commitment on License P.1465 (Bowmore blocks). As a result of the pooling IFR was obligated to pay 5% of the cost, US$2.1 million, to drill the Nexen operated North Bugle 15/23d-5 appraisal well. The company's options where to either forfeit its interest in P. 1465 or participate in drilling to preserve its interest in the license. The pooling was completed in early February and the well commenced drilling on February 19, 2010. At the time of agreeing to participate in the well the company had cash on hand of +/-C$3.5 million. Given the past experience the company had on cost over-runs in the North Sea a decision was made to sell the company's assets in the North Sea while the North Bugle well was drilling. In April two deals were completed, the first deal saw IFR sell its shares in its wholly owned UK subsidiary, Britcana Energy Ltd, to Nexen Petroleum UK Limited for a cash consideration of $3,119,520 plus the assumption of Britcana's US$2.1 million share of the North Bugle well cost. The second deal saw IFR sell its interest in License P. 233 (block 15/18a Maria) to Maersk Oil North Sea UK Limited for a cash consideration of $669,450.

Second Quarter

In Q2 a confidentiality agreement was signed with a TSX-V listed company and due diligence ensued on the possibilities of a merger. After numerous discussions centered on values for each company a deal was not concluded.

In June the company commissioned McDaniel & Associates Consultants Ltd to prepare a contingent resource report on the Summit Creek and Stewart Lake significant discovery licenses 138, 139 and 140 located in the Central Mackenzie Valley, NWT. The report assigned best estimate contingent resources of 1,471,000 barrels oil equivalent and a high estimate contingent resource of 6,029,000 barrels oil equivalent net to the company's interest in the subject SDL's.

Third Quarter

In Q3 a confidentiality agreement was signed with a TSX listed company that had a significant position in an emerging tight gas prospect plus conventional production of +/-8,400 BOEPD. The company chose not to proceed with merger discussions because of the other corporations bank debt coupled with weak gas prices.

The company acquired 640 acres on a channel sand light oil play located in south east Alberta; an additional 640 acre parcel has been posted on this prospect for a July land sale.

In the period EL-423 expired, the $24.5 million work commitment was fulfilled on the license via the drilling of the Dahadinni and Keele River wells.

Fourth Quarter

In December the Joint Review Panel issued its report on the Mackenzie Valley gas pipeline, the report basically approved construction of the pipeline subject to some +/- 175 conditions. The report was submitted to the National Energy Board ("NEB") for their review and comment.

In December the Department of Indian Affairs and Northern Development issued a call for nominations in the Northwest Territories. A call for nominations grants industry the right to post land for an upcoming land sale.

In Q4 the company submitted two farm-in proposal's, the first proposal was to deepen two of our Alderson wells to test a Pekisko play that Crew Energy is developing around our Alderson acreage in Twp 16 – Rge 11 W4M. Unfortunately Cenovous, who owns the deep rights on our Alderson lands, would not farm-out. The second farm-in proposal was for IFR to pay 33.33% of the cost to drill two vertical wells to earn a 25% interest in 2,560 acres in southern Alberta, IFR also committed to re-enter one of the wells to drill a horizontal leg and complete the horizontal section using multi-stage fracing. The owner of this acreage did not have sufficient finance in place to participate for the other 66.66% therefore a deal was not concluded.

In the period Husky Oil, operator of our CMV acreage, completed site restorations on the Summit Creek, Sah Cho and Stewart wells, the company's share of the costs was $151,120.

First Quarter 2011

On February 19th the Minister for the Department of Indian Affairs and Northern Development approved posting requests for eleven parcels of land covering an area of 897,890 hectares (2,218,735 acres more or less) located in the Central Mackenzie Valley, NWT. The postings cover an area of approximately 720 kilometers north-south and 300 kilometers east-west, this is the largest land sale ever to be held in the Central Mackenzie Valley. The sale closes on June 21, 2011 and results should be made public in Q3, 2011.

In March the NEB approved and granted a Certificate of Public Convenience and Necessity for the 1,196 kilometer long Mackenzie Valley Pipeline. The pipeline would run from the Beaufort Sea to Northwest Alberta, it is designed to transport up to 1.2 billion cubic feet per day. The proponents have until 2013 to advise the NEB of their intent to construct the pipeline.

Given the number of posting in the Central Mackenzie Valley, NWT ("CMV") the area is destined for another round of exploration. The postings essentially encompass the entire hydrocarbon basin south of the Norman Wells oilfield which has produced in excess of 250 million barrels of oil. The majority of the postings are located in areas where Devonian source rocks are known to exist therefore the play could turn out to be an unconventional shale oil play similar to unconventional plays being explored for with new horizontal drilling and multi-stage fracing technology. As the company's SDL lands do not expire any new play that is proven up in the CMV bodes well for IFR.

In March the company received an unsolicited offer to buy our five producing oil wells (100%) in the Alderson area of southern Alberta; the purchaser advised IFR that they did not receive Board of Directors approval to buy the property. With the current high oil price the company does not plan on selling the Alderson wells at the present time.

December 31, 2010 Audited Financial Statements.

In 2010 the company had net oil revenue of $474,515 (2009 - $603,235), the decrease in net revenue was the result of one well being shut-in coupled with an increase in operating costs on the Alderson oil pool. Included in 2010 operating costs are one time charges of $60,000 to replace pump jacks on two wells at Alderson. In 2011 we are forecasting production from Alderson at 26 BOPD with projected net revenue of $220,000.

In 2010 the company recorded a net loss from continued and discontinued operations of $6,223,375 ($0.10 per share) versus a net loss in 2009 of $14,713,450 ($0.25 per share). Included in the 2010 net loss is a non-cash charge of $5,032,270 (2009 - $8,561,840) for oil and gas property impairments and a non-cash charge of $112,675 (2009 - $256,820) for stock based compensation. The property impairment charge was the result of the company moving $4,189,210 to its depletable net cost base during 2010. The property impairment relates to the movement of all costs incurred in the Central Mackenzie Valley, NWT, other than costs relating directly to the Summit Creek and Stewart Lake Significant Discovery Licenses.

At December 31, 2010 the company had no debt and a positive working capital position of $6,457,185.

Central Mackenzie Valley, NWT

Significant Discovery Licenses

Summit SDL 140 – 8.2112% (no expiry)
Stewart SDL 138 & 139 – 8.2112% (no expiry)
TDL M-38 included within Stewart SDL – 25% (no expiry)
Operator – Husky Oil Operations Limited

The Summit Creek B-44 well was the first discovery in the CMV south of Norman Wells. The well production tested at a rate of 20 MMCF/D and 6,300 barrels of 55 degree API oil from two Devonian age formations. As a result of this discovery a Significant Discovery License (SDL 140) was awarded covering an area of 11,380 acres (17 sections).

The Stewart Lake D-57 well was the first well in the CMV to produce commercial flow rates from the Cretaceous formation. The D-57 well drill-stem tested 5 MMCF/D (un-stimulated) from two Cretaceous age formations. As a result of this discovery SDL's 138 & 139 were granted. The SDL, which includes TDL Freehold parcel M-38, covers an area of 16,987 acres (26 sections).

EL-441

IFR – 13.40%
Area – 218,500 acres (29,280 net)
Work Commitment - $10.5 million ($2M fulfilled)
Expiry - May 10, 2011.
Operator – Husky Oil Operations Limited
The Company has restricted cash securing a letter of credit in the amount of $266,365 which amount represents the Company's share of the remaining work deposit on EL-441. The letter of

credit is refundable on the basis of a one-dollar refund for every four-dollars of qualified allowable expenditures incurred. As there were no capital expenditures incurred on the license in Q4, 2010 the license will expire in May 2011. The company has booked a provision in its December 31, 2010 financial statements in the amount of $266,365 covering the cost for its share of the remaining work deposit that will be forfeited.

EL-443

IFR – 25%
Area – 227,750 acres (56,937 net)
Work Program - $4.8 million
Expiry – May 10, 2012
Operator – Husky Oil Operations Limited

The Company has restricted cash securing a letter of credit in the amount of $305,555, which amount represents the Company's share of the work deposit on EL-443. The letter of credit is refundable on the basis of a one-dollar refund for every four-dollars of qualified allowable expenditures incurred. There were no capital expenditures incurred on the license in Q4, 2010.

TDL Freehold Lands

IFR- 25%
Area – 35,000 acres (8,750 net)
Work Program – Nil
Operator – Husky Oil Operations Limited

In Q4 the Stewart Lake D-57 and Sah Cho D-57 wells that reside on TDL parcels M-37 & M-38 were plugged and the drilling sites were reclaimed. The company share of the costs are estimated to be $90,500.

EL-445

IFR-25%
Area – 206,000 acres (51,620 net)
Work Program - $1.1 million
Operator – Canadian Natural Resources Ltd.

The Company has restricted cash securing a letter of credit in the amount of $68,750 which amount represents the Company's share of the work deposit on EL-445. As there were no capital expenditures incurred on the license in Q4, 2010 the license will be relinquished in May 2011 and the company will forfeit its deposit in the amount of $68,750. The company has booked a provision in its December 31, 2009 financial statements in the amount of $68,750 covering the cost for its share of the remaining work deposit that will be forfeited.

Southern Alberta

Alderson Area

Operator – IFR 100%

The Company operates five producing oil wells and an oil battery located in the Alderson area of southern Alberta. The wells produce approximately 25 BOPD of 30 degree API oil from the Mannville Reservoir. In Q4 a new pump jack was installed on the 10-27 well and the well was placed back on production.

Liquidity, capital resources and financing activities

Working Capital

At December 31, 2010 cash and cash equivalents were $6,820,380 (December 31, 2009 $4,099,740), and working capital was $6,457,185 (December 31, 2009 - $7,865,635). At December 31, 2010 the Company had restricted cash securing letters of credit in the amount of $640,670; the letters of credit secure work deposits on the Company's Northwest Territories Exploration Licenses. At December 31, 2010 the Company set up a provision for EL-441 in the amount $266,365 (2009 - $68,750 for EL-445). These licenses will expire in May 2011 and the deposits in the amount of $266,365 and $68,750 respectively will be forfeited.

The decrease in working capital at December 31, 2010 is the result of decreased oil revenues and for costs incurred with respect to site reclamation expenditures in the Northwest Territories, mitigated by sale proceeds of $3,788,970 received from the sale of the Company's North Sea operations in the year.

Future Capital Requirements

The Corporation regularly forecasts its capital needs on an annual, quarterly and monthly basis. The Corporation's current internally generated cash flows do not provide sufficient capital for the Corporation's current exploration plans. Historically, the Corporation has relied on proceeds from the sale of its Common Shares to fund its operations. In order to accelerate the Corporation's current exploration programs the Corporation may require additional capital. The timing, pace, scope and amount of the Corporation's capital expenditures is largely dependent on the operators capital expenditure program(s) and the availability of capital to the Corporation.

The Corporation may obtain funds for future capital investments from strategic alliances with other energy or financial partners, the issuance of additional Common Shares, preferred shares or debt securities, project financing, sale of property interests, or other arrangements, all of which may dilute the interest of the Corporation's existing shareholders or the Corporation's interest in the specific project financed. The Corporation may change the allocation of capital among the categories of anticipated expenditures depending upon future events that the Corporation cannot predict. For example, the Corporation may change the allocation of its expenditures based on the actual results and costs of future exploration, appraisal, development, production, property acquisition and other activities. In addition, the Corporation may have to change its anticipated expenditures if costs of placing any particular discovery into production are higher, if the field is smaller or if the commencement of production takes longer than expected.

In the management of capital, the Company includes shareholders' equity,cash and cash equivalents, marketable securities and restricted cash less accounts payable and current portion asset retirement obligations in the definition of capital. Management reviews its capital requirements on an ongoing basis and believes that its approach, given the relative size of the Company is reasonable. As at December 31, 2010, the Company's capital as defined above was approximately $20,691,380 (December 31, 2009 – $24,700,725).

The Corporation has a number of options available to it if existing working capital does not cover future capital expenditures including, but not limited to, i) revising its capital expenditure plans ii) selling a partial or 100% interest in a property to a third party, iii) obtain joint venture financing from a third party, iv) obtaining debt financing, or a combination of these possible steps.

Annual Results

The following table summarizes results for the years 2010, 2009, and 2008.

	2010	2009	2008
Statement of operations			
Sales volumes - Barrels/ day (Canada)	28	35	40
Production volumes - Barrels/ day (Canada)	28	36	39
Oil revenues, net (Canada)	$ 474,515	$ 603,235	$ 970,060
Interest income from continuing operations	$ 18,150	$ 46,950	$ 460,895
Net loss and comprehensive loss			
Net loss from continuing operations	$ (6,110,125)	$ (7,775,875)	$ (2,722,875)
Net loss from discontinued operations	$ (113,250)	$ (6,937,575)	$ (1,437,345)
Net loss and comprehensive loss	$ (6,223,375)	$ (14,713,450)	$ (4,160,220)
Loss per share			
Net loss from continuing operations per share	$ (0.10)	$ (0.13)	$ (0.05)
Net loss from discontinued operations per share	$ (0.00)	$ (0.12)	$ (0.02)
Net loss per share	$ (0.10)	$ (0.25)	$ (0.07)
Cash flow			
Net cash provided (used in)			
Operating activities	$ (894,560)	$ (395,495)	$ 185,230
Investing activities	$ 3,615,200	$ (4,586,230)	$ (13,863,595)
Financing activities	$ -	$ -	$ (34,290)
Balance sheet			
Assets of Continuing operations			
Property and equipment	$ 7,511,710	$ 11,969,305	$ 20,846,600
Total assets	$ 15,283,980	$ 20,972,600	$ 38,255,075
Working capital	$ 6,457,185	$ 7,865,635	$ 9,325,705
Assets of Discontinued operations			
Cash and cash equivalents	$ -	$ 3,660	$ 523,835
Receivables	$ -	$ 9,020	$ 92,105
Property and equipment	$ -	$ 7,193,925	$ 5,291,290
Write down to lower of cost or market	$ -	$ (3,228,570)	$ -
	$ -	$ 3,978,035	$ 5,907,230

Sales Volumes

- Oil sales volumes in 2010 were 28 Bbl/day a 20% decrease as compared to 35 Bbl/day in 2009.
- Oil sales in 2010 were lower due to the 10-27 well being shut in during the year due to problems with the pump-jack
- Production volumes in 2010 were 28 Bbl/day a 21.94% decrease compared to 36 Bbl/day in 2009.
- Decrease in production volumes in the second and third quarters of 2010 is due to the 10-27 well being shut-in coupled with forecasted production declines.

Gross revenues and royalties

- Oil revenue in 2010 was $712,525 a decrease of 7.56% as compared to $770,810 in 2009.
- The decrease in oil revenues is due to decrease in sales volumes mitigated by an increase in price received of $68.83 per Bbl in 2010 as compared to $60.24 in 2009.
- During 2010 the Company paid royalties of $138,090 a decrease of 9.52% as compared to $152,620 in 2009
- During the year the Company paid $99,910 to employees and consultants pursuant to the Company`s Royalty Incentive Plan of this amount $75,795 was paid pursuant to the sale of the Company's North Sea operations.

Interest income

- In 2010 the Company earned interest income from short term investments of $18,150 (2009 - $46,950).
- The decrease in interest income in 2010 was due to a decrease in funds invested during the year.

Field operating costs

- Operating expenses in 2010 were $393,680 or $38.03 per Bbl an increase of 18.11% as compared to $333,315 or $26.05 per Bbl in 2009.
- Increased operating expenses in 2010 were a result of a pump jack changes on the 9-27 well in the third quarter ($20,000) and on the 10-27 well in the fourth quarter ($40,000).

Depletion and depreciation

Depletion, depreciation and impairments at December 31, 2010 and 2009 consist of the following;

December 31, 2010

Depletion, depreciation and impairments	Canada	Discontinued Operations- U.K	Total
Depletion of oil & gas properties	$ 408,455	$ -	$ 408,455
Impairment of oil & gas properties	5,032,270	-	5,032,270
Amortization of Sidox license	5,000	-	5,000
Depreciation of equipment	2,980	-	2,980
Write off Sidox License	20,000	-	20,000
	$ 5,468,705	$ -	$ 5,468,705

December 31, 2009

Depletion, depreciation and impairments	Canada	Discontinued Operations- U.K	Total
Depletion of oil & gas properties	$ 669,325	$ -	$ 669,325
Impairment of oil & gas properties	8,561,840	6,664,380	15,226,225
Amortization of Sidox license	5,000	-	5,000
Depreciation of equipment	3,815	-	3,810
	$ 9,239,980	$ 6,664,380	$ 15,904,360

- Depletion of oil and gas properties for the year ended December 31, 2010 was $408,455 or $39.46 per Bbl, a decrease of $260,870 or $12.85 per Bbl as compared to $669,325 or $52.31 per Bbl for the same period in 2009.
- The decrease in depletion in 2010 was due to an increase in the depletable net cost base in the amount of $4,189,210 during the year as compared to $9,648,505 during 2009.
- At December 31, 2010 an impairment test was performed which calculates the amount by which the carrying amount of capitalized costs related to producing properties exceeds the fair value of the reserves as estimated by the Company's reservoir engineers at December 31, 2010. As a result a $5,032,270 (2009 - $8,561,840) impairment charge of petroleum and natural gas assets has been recorded as part of depletion to reflect the excess carrying amount of assets over fair value of future reserves in Canada.

- In 2010, the Company recognized an impairment expense of $Nil (2009 - $6,664,380) for dry hole costs and G&A expenses incurred in the North Sea. As at December 31, 2010, no additional impairment was identified with respect to unproved properties in the North Sea.
- The carrying value of properties in the exploration stage in the Northwest Territories of $6,491,090 (December 31, 2009 - $10,072,160) and in the North Sea of $Nil (December 31, 2009 - $7,223,925) have been excluded from the full cost pool at December 31, 2010. These properties were evaluated at December 31, 2010 and it was determined that no additional costs were required to be included in the carrying amount of capitalized costs for purposes of calculating depletion and impairment.

Accretion of asset retirement obligation

- Accretion of asset retirement obligations at December 31, 2010 were $56,855, an increase of $7,920 compared to $48,935 in 2009.

General and administrative expenses

	2010	2009	2008
Investor relations	$ 18,650	$ 60,110	$ 36,880
Filing and transfer fees	23,255	21,535	26,340
Accounting and legal	100,700	105,760	123,765
Consulting fees - gross	328,435	310,640	332,010
Consulting fees - capitalized	(49,250)	(130,950)	(116,600)
Rent and office costs	149,085	190,660	213,245
Part 12.6 Tax	-	-	7,820
	$ 570,875	$ 557,755	$ 623,460

- In 2010 general and administrative expenses were $570,875 which is consistent with the prior year at $557,755.
- Steps were taken in Q2 to reduce G&A costs which will be reflected in 2011.

Stock based compensation

- Stock based compensation costs of $112,675 were calculated using the Black Scholes model for options granted in the fourth quarter of 2010.

Net loss

For the year ended December 31, 2010 the Company recorded a consolidated net loss of $6,223,375 ($0.10 loss per share).

Net earnings (loss):	**2010**	**2009**	**2008**
Net loss from continuing operations	$ (6,110,125)	$ (7,775,875)	$ (2,722,875)
Net loss from discontinued operations	(113,250)	(6,937,575)	(1,437,345)
Consolidated net loss	$ (6,223,375)	$ (14,713,450)	$ (4,160,220)

Loss per share			
Continuing operations	$ (0.10)	$ (0.13)	$ (0.05)
Discontinued operations	$ (0.00)	$ (0.12)	$ (0.02)
Loss per share	$ (0.10)	$ (0.25)	$ (0.07)

- Net loss from continuing operations decreased in 2010 as compared to 2009 due to an impairment of oil and gas properties in the Northwest Territories in the amount of $8,561,840 booked at December 31, 2009 (December 31, 2010 - $5,032,270)
- The loss from discontinued operations is represented by a net loss from U.K. operations at December 31, 2010 of $89,610 (2009 - $3,709,005) and loss booked on the impairment of assets of discontinued operations of $23,640 (2009 - $3,228,570)

Financial Instruments

As disclosed in Note 3 to the consolidated financial statements, the Company holds various forms of financial instruments. The nature of these instruments and the Company's operations expose the Company to interest rate risk, foreign exchange risk, fair value risk and industry credit risk. The Company manages its exposure to these risks by operating in a manner that minimizes its exposure to the extent practical.

a) Fair value of financial assets and liabilities: The Company's financial instruments as at December 31, 2010 and 2009 include cash and cash equivalents, trade accounts receivable, restricted cash and trade accounts payable. The fair values of trade accounts receivable and trade accounts payable approximate their carrying amounts due to their short terms to maturity. The cash and cash equivalents and the restricted cash balances are equal to their fair values.

	2010		2009	
	Carrying Value ($)	**Fair Value ($)**	**Carrying Value ($)**	**Fair Value ($)**
Financial assets:				
Receivables	$ 119,570	$ 119,570	$ 144,295	$ 144,295
Total financial assets	$ 119,570	$ 119,570	$ 144,295	$ 144,295
Financial liabilities				
Payables and accruals	$ 607,600	$ 607,600	$ 212,575	$ 212,575
Total financial liabilities	$ 607,600	$ 607,600	$ 212,575	$ 212,575

The Company classifies the fair value of financial instruments held for trading according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

At December 31, 2010 cash and cash equivalents and restricted cash have been classified as Level 1.

b) **Credit risk:** Substantially all of the accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Though, the Company markets its oil to only one marketer revenues are not significant so that the exposure to the Company is minimized. Management does not believe that there is significant credit risk arising from any of the Company's customers or partners, as substantially all amounts outstanding at December 31, 2010 have been received subsequent to period end. The maximum exposure to loss arising from accounts receivable at any given time is equal to their total carrying amounts on the balance sheet.

Total receivables:	**0 to 30 days**	**31 to 60 days**	**61 to 90 days**	**Greater than 90 days**
$ 119,570	$ 92,810	$ -	$ 18,200	$ 8,560

c) **Interest rate risk:** The Company is exposed to interest rate cash flow risk to the extent the changes in market interest rates will impact the Company's interest rate price risk. In addition, the Company is also exposed to interest rate risk to the Canada Revenue Agency for interest on unexpended funds on the Company's flow through share obligations from February 1 to December 31 of each year. The Company does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations. A 1% increase or decrease in interest rates would have had no material impact on the cash flow of the Company during the period ended December 31, 2010.

d) **Liquidity risk:** Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's objective in managing liquidity risk is to ensure that it has sufficient resources available to meet its liabilities when due. At December 31, 2010, the Company's accounts payable and accrued liabilities were $607,600 all of which are due for payment within normal terms of trade which is generally between 30 and 60 days. The Company regularly reviews its accounts payable balances and follows up on amounts past due. The Company's financial liabilities are summarized below:

Total payables:	0 to 30 days	31 to 60 days	61 to 90 days	Greater than 90 days
$ 607,600	$ 405,410	$ 100,680	$ 1,580	$ 99,930

Investing Activities

	Twelve months ended December31,					
	2010			2009		
	Canada	Discontinued Operations	Total	Canada	Discontinued Operations	Total
Cash Expenditures	$ 203,760	$ 108,870	$ 312,630	$ 811,130	$ 5,409,380	$ 6,220,510
EL -441 Accrual	$ 266,365	-	266,365	-	-	-
PNG Recoveries	-	-	-	(453,710)	(273,660)	(727,370)
	$ 470,125	$ 108,870	$ 578,995	$ 357,420	$ 5,135,720	$ 5,493,140

- Capital expenditures in 2010 were 312,630 (2009 - $5,493,140) of which $203,760 or 65% (2009 – 5%, 2008 – 68%) is related to exploration activities in the Northwest Territories and $108,870 or 35% (2009 – 95%, 2008 – 32%) is related to exploration activities of discontinued operations in the U.K. North Sea.
- In the North Sea capital expenditures of $108,870 relate to costs incurred for the drilling of the Company's 10% share of the Bowmore – Alpha 15/24a-9 well.

Obligations

- The Company is party to an agreement to lease its premises until December 31, 2014. The annual rent of premises consists of a minimum rent payment of $53,980 plus occupancy costs for 2011 and $43,120 plus occupancy cost per year for 2012 to 2014.
- The Company has established a Royalty Incentive Agreement for employees, consultants and senior executives that are also directors. Under the plan, the compensation committee issues units on an annual basis to employees, consultants and directors. The units entitle the holder to receive an annual payment based on 2% of the Company's annual production revenue, net of transportation and processing fees. Under the terms of the agreement, once the Company has recovered payout of 100% of its cumulative annual capital expenditures from licenses and lands owned by the Company, the payment to employees, consultants and directors is based on 4% of the Company's annual production revenue less transportation and processing fees. At December 31, 2010, payout of 100% of cumulative annual capital expenditures had been reached on the Alderson oil property.

Related Party Transactions

Certain officers who are directors and consultants provide professional, consulting and management services to the Company and are eligible to receive royalties pursuant to the Company's Royalty Incentive Plan. The amounts paid to officers (directors) and consultants during for the period ending December 31, 2010 are provided below, these costs are included in general and administrative expenses on the consolidated statements of earnings (loss), deficit and comprehensive earnings (loss) at December 31, 2010:

- Compensation paid to executive officers was $166,500 (2009 - $109,500) of which $49,250 (2009 - $65,475) was capitalized to property and equipment for the year ended December 31, 2010. Included in this amount is a severance payment of $72,000 plus benefits paid to a former Officer and Director of the Company.
- At December 31, 2010 royalties of $99,910 (2009 - $11,145) were paid to officers and consultants pursuant to the Company's Royalty Incentive Plan. Royalties paid in the period include an amount of $75,795 covering the sale of the Company's North Sea operation.

Summary of Fourth Quarter Results

Selected financial information:

	Three months ended, December 31, 2010	Three months ended, December 31, 2009	Three months ended, Nine months ended September 30, 2010	Three months ended, Nine months ended September 30, 2009
Statement of operations				
Sales volumes - Barrels/ day (Canada)	29	36	26	35
Production volumes - Barrels/ day (Canada)	26	34	31	37
Oil revenues, net (Canada)	$ 145,940	$ 180,885	$ 111,445	$ 162,280
Interest income from continuing operations	$ 15,355	$ 380	$ 1,055	$ 12,050
Net earnings (loss) and comprehensive loss				
Net earnings (loss) from continuing operations	$ (5,192,815)	$ (2,294,220)	$ (100,335)	$ (1,682,195)
Net loss for discontinued operations	$ (1,185)	$ (6,764,310)	$ -	$ (1,809,830)
Net earnings (loss) and comprehensive loss	$ (5,194,000)	$ (9,058,530)	$ (100,335)	$ (3,492,025)
Net earnings(loss) per share				
Net loss from continuing operations per share	$ (0.09)	$ (0.04)	$ (0.00)	$ (0.03)
Net loss from discontinued operations per share	$ (0.00)	$ (0.11)	$ (0.00)	$ (0.03)
Net loss per share	$ (0.09)	$ (0.15)	$ (0.00)	$ (0.06)
Cash flow				
Net cash provided (used in)				
Operating activities	$ (253,005)	$ (146,220)	$ (77,935)	$ 28,750
Investing activities	$ 28,130	$ 188,515	$ 24,500	$ (2,244,780)
Financing activities	$ -	$ -	$ -	$ -
	December 31, 2010	**December 31, 2009**		
Balance sheet				
Assets of Continuing operations				
Property and equipment	$ 7,511,710	$ 11,969,305		
Total assets	$ 15,283,980	$ 20,972,600		
Working capital	$ 6,457,185	$ 7,865,635		

Sales Volumes

- Production volumes for the three months ended December, 31, 2010 were 26 Bbl/day a decrease of 18.67% as compared to 31 Bbl/day for the three months ended September 30, 2010.
- The decrease in production volumes in Q-4, 2010 was a result of the 10-27 well being shut-in due to the need to replace the pump jack.
- Sales volumes for the three months ended December 31, 2010 were 29 Bbl/day compared to 26 Bbl/day for the three months ended September 30, 2010.

Gross revenues and royalties

- Oil revenue in Q4 was $186,640 an increase of 20.78% compared to Q3 (Q3-2010 - $154,525, Q4-2009 - $228,340).
- In Q4 the Company paid royalties of $33,400 which is consistent with $37,055 in the previous quarter (Q4-2009 - $43,000)
- The increase in oil revenues in the fourth quarter of 2010 is due to slight increase in sales volumes coupled with an increase in oil price received in the period.

Interest income

- In Q-4 2010 interest income from short term investments was $15,355 (Q3-2010 - $1,055, Q4-2009 - $380) the increase is due to an increase in interest rates received in Q4-2010 coupled with an increase in the amount invested.

Field operating costs

- Operating expenses in the fourth quarter were $146,715 or $55.14 per Bbl (Q3-2010 - $57,685 or $24.12 per Bbl, Q4- 2009 - $ 100,500 or $31.68)
- The increase in operating costs in Q4-2010 was the result of well work-overs and an increase in facility costs at Alderson.

Depletion, depreciation and impairments

Depletion, depreciation and impairments for the three months ended December 31, 2010 and September 30, 2010 respectively consist of the following

December 31, 2010

Depletion, depreciation and impairments	Canada	Discontinued Operations	Total
Depletion of oil and gas properties	$ 195,150	$ -	$ 195,150
Impairment of oil and gas properties	4,691,345	-	4,691,345
Amortization of Sidox license	1,250	-	1,250
Depreciation of equipment	680	-	680
Write off Sidox License	20,000	-	20,000
	$ 4,908,425	$ -	$ 4,908,425

September 30, 2010

Depletion, depreciation and impairments	Canada	Discontinued Operations	Total
Depletion of oil & gas properties	$ 64,810	$ -	$ 64,810
Impairment of oil & gas properties	-	-	-
Amortization of Sidox license	1,250	-	1,250
Depreciation of equipment	720	-	720
	$ 66,780	$ -	$ 66,780

- Depletion of oil and gas properties for the three months ended December 31, 2010 was $195,150 or $73.34 per Bbl, an increase of $130,340 or $46.24 per Bbl as compared to $64,810 or $27.09 per Bbl for the third quarter of 2010.

- The increase in depletion is due to a slight decrease in reserves as estimated by McDaniel's & Associates at December 31, 2010 coupled with an increase in the amount of $4,189,210 in the depletable cost base in the fourth quarter.

Accretion of asset retirement obligation

- Accretion of asset retirement obligations for the three months ended December 31, 2010 was $17,185 compared with $13,520 in Q-3 2010.
- The increase in the fourth quarter was a result of an increase in the estimated asset retirement liability with respect to the Northwest Territories wells at October 1, 2010.

General and administrative expenses

Three Months Ended	December 31, 2010		September 30, 2010		December 31, 2009	
Investor relations	$	155	$	-	$	845
Filing and Transfer Fees	$	270	$	9,460	$	1,890
Professional Fees	$	69,165	$	4,120	$	66,490
Consulting Fees – gross	$	64,255	$	46,030	$	84,100
Consulting Fees – capitalized	$	(6,245)	$	(6,240)	$	(35,400)
Rent and office Costs	$	41,510	$	22,490	$	43,040
	$	169,110	$	74,860	$	160,965

- In Q4 general and administrative expenses were $169,110, an increase of $94,260 or 125.93% as compared with $74,860 in Q3.
- The increase in G&A is due to year end accruals for accounting fees at December 31, 2010.

Net loss

Three months ended:	Q-4 2010		Q-3 2010		Q-4 2009	
Net loss from continuing operations	$	(5,192,815)	$	(100,335)	$	(2,294,220)
Net loss from discontinued operations		(1,185)		-		(6,764,310)
Net loss	$	(5,194,000)	$	(100,335)	$	(9,058,530)
Loss per share						
Continuing operations	$	(0.09)	$	(0.00)	$	(0.04)
Discontinued operations	$	(0.00)	$	(0.00)	$	(0.11)
Loss per share	$	(0.09)	$	(0.00)	$	(0.15)

The increased loss in Q4 as compared with Q3 is a result of the following adjustments.

- An impairment charge on oil and gas properties totaling $4,691,345 in Q-4 2010
- Accrual for year-end audit fees and 51-101 reserve report costs of $72,500.
- Stock based compensation expense of $112,675 in Q-4 for options issued in that period

Summary of Quarterly Results

The following table summarized the Company's financial and operating highlights for the past eight quarters:

Quarter ended:	**March 31, 2009**	**June 30, 2009**	**Sept 30, 2009**	**Dec 31, 2009**
Statement of operations				
Sales volumes - Barrels/ day (Canada)	35	34	35	36
Production volumes - Barrels/ day (Canada)	36	35	37	34
Oil revenues, net (Canada)	$ 110,835	$ 149,235	$ 162,280	$ 180,885
Net earnings (loss) and comprehensive loss				
Net earnings (loss) from continuing operations	$ (99,930)	$ (3,669,530)	$ (1,682,195)	$ (2,294,220)
Net loss for discontinued operations	$ (4,655)	$ (2,873,875)	$ (1,809,830)	$ (6,764,310)
Net earnings (loss) and comprehensive loss	$ (104,585)	$ (6,543,405)	$ (3,492,025)	$ (9,058,530)

Quarter ended:	**March 31, 2009**	**June 30, 2009**	**Sept 30, 2009**	**Dec 31, 2009**
Net earnings(loss) per share				
Net loss from continuing operations per share	$ (0.00)	$ (0.06)	$ (0.03)	$ (0.04)
Net loss from discontinued operations per share	$ (0.00)	$ (0.05)	$ (0.03)	$ (0.11)
Net loss per share	$ (0.00)	$ (0.11)	$ (0.06)	$ (0.15)
Balance Sheet				
Total assets	$38,255,075	$37,219,740	$ 29,980,890	$ 20,972,600
Working capital	$15,179,905	$10,239,230	$ 4,279,660	$ 7,865,635
Refundable Deposits	$ 2,267,175	$ 1,520,315	$ 925,060	$ 640,670
Funds flow from operations	$ (184,590)	$ (75,685)	$ (188,805)	$ (146,220)

Quarter ended:	**Mar 31, 2010**	**June 30, 2010**	**Sept 30, 2010**	**Dec 31, 2010**
Statement of operations				
Sales volumes - Barrels/ day (Canada)	28	30	26	28
Production volumes - Barrels/ day (Canada)	33	25	31	28
Oil revenues, net (Canada)	$ 148,225	$ 151,820	$ 111,445	$ 145,940
Net earnings (loss) and comprehensive loss				
Net earnings (loss) from continuing operations	$ (165,860)	$ (651,115)	$ (100,335)	$ (5,192,815)
Net loss for discontinued operations	$ (104,255)	$ (7,810)	$ -	$ (1,185)
Net earnings (loss) and comprehensive loss	$ (270,115)	$ (658,925)	$ (100,335)	$ (5,194,000)
Net earnings(loss) per share				
Net loss from continuing operations per share	$ (0.04)	$ (0.01)	$ (0.00)	$ (0.09)
Net loss from discontinued operations per share	$ (0.11)	$ (0.00)	$ (0.00)	$ (0.00)
Net loss per share	$ (0.15)	$ (0.01)	$ (0.00)	$ (0.09)
Balance Sheet				
Total assets	$20,719,095	$19,708,385	$ 19,531,265	$ 15,283,980
Working capital	$ 7,646,280	$ 7,310,610	$ 7,186,425	$ 6,457,185
Refundable Deposits	$ 640,670	$ 640,670	$ 640,670	$ 640,670
Funds flow from operations	$ (126,625)	$ (436,995)	$ (77,935)	$ (251,820)

Other Items

Outstanding shares, options and warrants

The Company's share capital structure is as follows:

As of:	December 31, 2010	April 13, 2011
Common shares outstanding	59,578,965	59,578,965
Options outstanding	4,206,500	4,206,500
Fully diluted	63,785,465	63,785,465

Additional details on the shares, options and warrants outstanding at December 31, 2010 are available in the notes to the December 31, 2010 audited consolidated financial statements.

Changes in accounting policies and new pronouncements

The Company is assessing the new and revised accounting pronouncements that have been issued that are not yet effective:

(a) International Financial Reporting Standards (IFRS)

IFRS Transition Plan

Effective January 1, 2011, Canadian public companies are required to adopt International Financial Reporting Standards ("IFRS"). The Corporation has developed a plan to complete the transition to IFRS by January 1, 2011, including the preparation of 2010 required comparative information. The Company's transition plan includes training and development throughout the organization, and three key phases:

Scoping and diagnostic phase

Phase 1 involves performing a high level diagnostic analysis to identify areas that may be affected by the transition to IFRS. The results of this analysis are priority ranked according to complexity and the amount of time required to assess the impact of changes in transitioning to IFRS.

Impact analysis and evaluation phase

During this phase, items identified in the diagnostic phase are addressed according to the priority levels assigned to them. This phase involves analysis of policy choices allowed under IFRS and their impact on the financial statements. In addition, certain potential differences are further investigated to assess whether there may be a broader impact to the Company's business processes or management reporting systems. The conclusion of the impact analysis and evaluation phase will require the Audit Committee of the Board of Directors to review and approve all accounting policy choices as proposed by management.

Implementation phase

Phase 3 involves implementation of all changes approved in Phase 2 and will include changes to information systems, business processes, modification of agreements and training of all staff who are impacted by the conversion. In 2010, the Company made significant progress on its transition plan, completing Phase 1 and moving into Phase 2, and conducting preliminary impact analysis of accounting policy alternatives.

Management has finalized its IFRS accounting policies for significant impact areas (excluding income tax) and is in the process of quantifying the expected financial impact of these policies on the IFRS opening balance sheet at January 1, 2010.

IFRS accounting policies:

The Company has evaluated all significant accounting policy differences between IFRS and Canadian GAAP. Each of these differences and the expected financial impact on the IFRS opening balance sheet is discussed in more detail below. All chosen IFRS accounting policies are still being reviewed and in the process of being approved by the Audit Committee of the Board of Directors at this time. The Company's analysis of the chosen IFRS accounting policies specifically considers the current IFRSs that are in effect. As a result, any new or amended accounting standards that are issued by the International Accounting Standards Board ("IASB") in future periods may impact our current assessment of the chosen IFRS accounting policies and the expected financial impact on transition to IFRS.

Property, Plant & Equipment

Property and Equipment is the most significant area impacted by the adoption of IFRS. The Company currently follows the Canadian GAAP guidelines on full cost accounting for oil and gas companies. IFRS has no equivalent guideline. In order to facilitate the transition to IFRS by full cost oil and gas companies, the IASB issued amendments to IFRS 1 *First-time Adoption of IFRS* allowing additional exemptions for first-time adopters of IFRS. Under these amendments, full cost oil and gas companies can elect to use the recorded amount under Canadian GAAP as the "deemed cost" for oil and gas assets on the transition date to IFRS.

Companies that elect to use this IFRS 1 exemption on transition will need to decide whether to allocate costs based on reserve volumes or values using either proved or proved plus probable reserves. Without this exemption, the Company would have been required to retrospectively determine the carrying amount of oil and gas assets at the date of transition, or use the fair value or revaluation amount as the new deemed cost under IFRS. The Company will use this exemption on transition to IFRS and allocate the existing net book value of its oil and gas full cost pool at the area level using proved plus probable reserve volumes. By using the exemption, the net book value of the Company's Property and Equipment at the date of transition to IFRS will be the same as it was under Canadian GAAP subject to any impairment provisions.

In moving to IFRS, the Company will be required to adopt different accounting policies for pre-exploration activities, Exploration and Evaluation ("E&E"), DD&A, and accounting for gains and losses on property dispositions, significant components of PP&E and other material non-monetary transactions.

Pre-exploration costs

- These are costs incurred before the Corporation obtains the legal right to explore an area. Under Canadian GAAP, these costs are capitalized, while under IFRS, these costs must be expensed.

Exploration and evaluation ("E&E") costs

- Currently these costs are included in the PP&E balance on the Balance Sheet, and include undeveloped land and costs relating to pre-commercial exploration of development. These costs are currently not being depleted. Under IFRS these costs will be moved out of the PP&E balance, and reported separately as E&E assets on the balance sheet. E&E costs will not be depleted but assessed for impairment and unrecoverable costs associated with a specific area will be expensed. When a project is determined to be technically feasible and commercially viable, the costs will be moved to PP&E and depletion will commence.

<u>Calculation of depletion expense</u>

- Under Canadian GAAP, the Company calculates its DD&A rate at the country cost centre level. Under IFRS, this rate will be calculated at a lower unit of account.
- Under IFRS, the Company has the alternative to either continue depleting its assets over proved reserves (same as Canadian GAAP) or use another basis which more accurately reflects the useful life of the Company's oil and gas assets
- The Company will calculate its DD&A rate at the area level and deplete its oil and gas assets over proved plus probable reserves on transition to IFRS.

<u>Divestitures</u>

- Full cost oil and gas accounting under Canadian GAAP requires that gains or losses on divestitures of properties are only recognized when the disposal would affect the DD&A rate by 20% or more. Under IFRS, there is no such exemption, and therefore the Company will be required to recognize all gains and losses on property divestitures and from disposal of significant components of PP&E.
- There is no impact of adopting this IFRS accounting policy at January 1, 2010.

<u>Impairment testing</u>

- Under Canadian GAAP, the recoverable amount of the Company's oil and gas assets under the first step of the impairment test is determined using undiscounted future cash flow from proved reserves. Under IFRS, the recoverable amount is the higher of the fair value less costs to sell the asset, or its "value in use" which is the discounted cash flows expected to be obtained from using the asset. Under Canadian GAAP the impairment test is performed at the country cost centre level, while under IFRS it will be performed at a lower level referred to as a cash-generating unit.
- Canadian GAAP prohibits reversal of impairment losses. Under IFRS, if the conditions giving rise to impairment have reversed, impairment losses previously recorded would be partially or fully reversed to eliminate write-downs recorded. The Company expects to adopt these changes in accounting policy prospectively.
- The Company has identified a single cash-generating unit relating to its producing property at the date of transition. The Company did not have an impairment of its petroleum and natural gas assets under IFRS at January 1, 2010.

As a result of the additional IFRS 1 exemptions released by the IASB in July 2009, the Company anticipates that all changes to its PP&E accounting policies will be adopted prospectively at date of transition.

Decommissioning liabilities (known as "asset retirement obligations" under GAAP)

- Under Canadian GAAP, the Corporation recognizes a liability for the estimated fair value of the future retirement obligations associated with PP&E. The fair value is capitalized and amortized over the same period as the underlying asset. The Company estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in wells and facilities, including an estimate for the timing of the costs to be incurred in future periods. These cash outflows are discounted using a credit-adjusted rate. Changes in the net present value of the future retirement obligation are expensed through accretion as part of DD&A.
- Under IFRS, these liabilities are known as "decommissioning liabilities" and are included in the scope of IAS 37 Provisions, Contingent Liabilities and Contingent Assets. Decommissioning liabilities are calculated at each reporting period using estimate of risk-adjusted future cash outflows discounted using a risk-free rate. Changes in the net present value of the future retirement obligation are expensed through accretion as part of DD&A.
- Due to the change in the discount rate from a credit-adjusted rate to a risk-free rate, The Company will record an increase in discounted future asset retirement obligation with the offset to retained earnings on transition at January 1, 2010. The Company is still in the process of determining the final adjustment with respect to the transition to IFRS.

Stock-based compensation

- IFRS 2 Share-Based Payments requires the expense related to share-based payments to be recognized as the options vest. For options with different vesting periods, each vesting tranche must be treated as a separate option grant which accelerates the expense recognition ("Graded Vesting Amortization") in comparison to Canadian GAAP, which allows the expense to be recognized on a straight-line basis over the period the options vest.
- The Company must also apply an estimated forfeiture rate at the initial grant date for each option tranche.
- The Company's options vest 100% upon issuance and a forfeiture rate has already been incorporated in the Company's valuation of share based payments, therefore, there will be no impact of adopting this IFRS accounting policy at January 1, 2010.

Income Tax

- In transitioning to IFRS, the carrying amount of the Company's deferred tax balances will be directly impacted by the tax effects resulting from changes required by the above IFRS accounting policy differences.
- The Company is still determining the impact of the revised standard on its IFRS transition. Therefore, at this time the income tax impacts of the differences are not reasonably determinable.

Changes to IFRS Accounting Standards

The Company's analysis of accounting policy differences specifically considers the current IFRS standards that are in effect. The Corporation will continue to monitor any new or amended accounting standards that are issued by the IASB in future periods.

Internal Controls over Financial Reporting

The Company does not anticipate that the transition to IFRS will have a significant impact on either its internal controls over financial reporting, or its disclosure controls and procedures. As the review of the Company's accounting policies is completed, an assessment will be made to determine changes necessary for internal controls over financial reporting. For example, additional controls and review will be implemented as necessary for the IFRS 1 changes such as the allocation of the Company's PP&E as well as the process for reclassifying E&E expenditures from PP&E on transition. This will be an ongoing process throughout 2010 to ensure that all changes in accounting policies include the appropriate additional controls and procedures for future IFRS reporting requirements.

Throughout the transition, The Company will assess stakeholders' information requirements and will ensure that adequate and timely information is provided so that all stakeholders remain apprised.

Education and Training

All of the individuals that are involved in financial reporting under Canadian GAAP have been engaged and involved in the IFRS transition project since 2008, and will continue to be involved in the IFRS transition throughout 2010 and 2011.

Impacts to our Business

The Company does not expect that the adoption of IFRS in 2011 will have a significant impact or influence on its business activities, operations or strategies.

(b) Business Combinations

- In January 2009, the CICA issued new standards for Business Combinations. This standard is effective January 1, 2011 and applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after January 1, 2011 for the Company. Early adoption is permitted. This standard replaces Handbook Section 1581 Business Combinations, and harmonizes the Canadian standards with IFRS. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. The adoption of this standard will not have a material impact on the Company's financial statements.

(c) Consolidated Financial Statements and Non- controlling Interests

- January, 2009, CICA Handbook Section 1601 – Consolidated Financial Statements was issued which, together with new CICA Handbook Section 1602 – Non-controlling Interests, replaces the former Section 1600 – Consolidated Financial Statements. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 is equivalent to the corresponding provisions of International Financial Report Standards IAS 27 – Consolidated and Separate Financial Statements. Sections 1601 and 1602 apply to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011. The Corporation does not anticipate that these sections will have a material impact on its financial statements.

Critical Accounting Estimates

Management is required to make judgments, assumptions and estimates in the application of Canadian generally accepted accounting principles that have a significant impact on the financial results of the Company. Reserve estimates are a key component in the calculation of depletion, depreciation and accretion costs. A change in reserve quantity estimates will result in a corresponding change in DD&A costs. In addition, if capitalized costs are determined to be in excess of the calculated ceiling, which is based on reserve quantities and values, the excess must be written off as an expense. Asset retirement costs are estimated, discounted and carried on the balance sheet as a liability. A change in estimated future asset restoration costs will change the liability on the balance sheet and the amortization of the asset retirement costs included in property and equipment.

Operational and other business risks

Current Economic Conditions

The volatility in the price of oil and natural gas has created a substantially more volatile business environment. These conditions may limit certain of the Company's business activities and it will continue to provide risk for International Frontier's exploration projects.

Need to Replace and Grow Reserves

The future oil and natural gas production of International Frontier, and therefore future cash flows, are highly dependent upon ongoing success in exploring its current and future undeveloped land base, exploiting the current producing properties, and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, reserves and production will decline over time as reserves are depleted.

The business of discovering, developing, or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, the ability of International Frontier to make the necessary capital investments to maintain and expand its oil and natural gas reserves may be impaired.
There can be no assurance that International Frontier will be able to find and develop or acquire additional reserves to replace and grow production at acceptable costs.

Exploration, Development and Production Risks

Oil and natural gas exploration in the Central Mackenzie Valley, NWT involves a high degree of risk, which even with a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration by International Frontier will result in new discoveries of oil and natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones, tools lost in the hole and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

The long-term commercial success of International Frontier depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that International Frontier will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participation are identified, International Frontier may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recover of drilling, completion and operating cost. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rate over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.
In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blowouts, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Reserve Estimates

The production forecast and recoverable estimates contained in International Frontier's engineering report are only estimates and the actual production and ultimate recoverable reserves from the properties may be greater or less than the independent estimates of McDaniel & Associates Consultants Ltd. There is no certainty that it will be commercially viable to produce any portion of the contingent resources identified in the June 30, 2010 McDaniel & Associates report.

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived thereof, including many factors that are beyond the control of International Frontier. The reserve and cash flow information set forth herein represent estimates only. The reserves and estimated future net cash flow from the assets of International Frontier have been independently evaluated effective December 31, 2010 by McDaniel & Associates Consultants Ltd. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditure, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of International Frontier. Actual production and cash flows derived thereof will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived thereof contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

Contingent Resources

The resources assigned to the Company's properties have been classified as contingent. The Canadian Oil and Gas Evaluation Handbook (COGEH) Volume 1 defines contingent resources as quantities of oil and gas estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be sub classified based on project maturity and/or characterized by their economic status.

- Low Estimate: This is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulations. If probabilistic methods are used this term reflects a P90 confidence level.
- Best Estimate: This is considered to be the best estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used this term is a measure of the central tendency of the uncertainty distribution (most likely/mode, P50/median, or arithmetic average/mean).
- High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term reflects a P10 confidence level.

There is no certainty that a gas pipeline will be constructed to tie-in the Company's contingent resources, nor is there certainty that it will be commercially viable to produce any portion of the contingent resources identified in the McDaniel & Associates contingent resource report date December 2010.

Volatility of Oil and Natural Gas Prices

The operational results and financial condition of International Frontier will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect of the operations, proved reserves, and financial conditions of International Frontier and could result in a reduction of the net production revenue of the Company causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings which might be made available to the Company are typically determined in part by the borrowing base of the reserves of International Frontier. A sustained material decline in prices from historical average prices could reduce the borrowing base of International Frontier, therefore reducing the bank credit available to International Frontier and could require that a portion of such bank debt be repaid.

International Frontier uses the full cost method of accounting for oil and natural gas properties. Under this accounting method, capitalized costs are reviewed on a quarterly basis for impairment to ensure that the carrying amount of these costs is recoverable based on expected future cash flows.

Operational Hazards and Other Uncertainties

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, and oil spills, each of which could result in substantial damage to oil and natural gas wells, production faculties, other property and the environment or in personal injury. In accordance with industry practice, International Frontier is not fully insured against all of these risks, nor is all such risks insurable. Although International Frontier will maintain liability insurance, where available, in an amount which it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event International Frontier could incur significant costs that could have a material adverse affect upon its financial condition. Business interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such equipment or access restrictions may affect the availability and/or cost of such equipment to International

Frontier and may delay exploration and development activities. To the extent International Frontier is not the operator of its oil and gas properties, the Company will be dependent on other operators for timing of activities related to non-operating properties and will be largely unable to direct or control the activities of the operators.

Although property title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of International Frontier which could result in reduction of the revenue received by the Company.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. International Frontier will actively compete for capital, skilled personnel, undeveloped land, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than does International Frontier. There can be no certainty that the Company's bid for new acreage in the CMV will successful as the competition for land in the CMV will likely increase if a gas pipeline is constructed.

Key Personnel

The success of International Frontier will depend in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on International Frontier. International Frontier does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of International Frontier are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that International Frontier will be able to continue to attract and retain all personnel necessary for the development and operation of its business.

Environmental Risks

The oil and natural gas industry is subject to environmental regulation pursuant to a variety of international conventions and Canadian federal, provincial and municipal laws, regulations, and guidelines. A breach of such regulations may result in the imposition of fines or issuances of clean up orders in respect of International Frontier or its assets. Such regulation may be changed to impose higher standards and potentially more costly obligations on International Frontier. There can be no assurance that future environmental costs will not have a material adverse affect on International Frontier. The Company's current exploration acreage is located in the CMV and as such there is additional environmental risk that may not exist in other hydrocarbon basins.

Forward Looking Statements

Certain statements contained in this MD&A constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "strategy" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements 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 MD&A should not be unduly relied upon. These statements are made only as of the date of this MD&A.

In particular, this MD&A may contain 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;
- 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.

With respect to forward-looking statements contained in this MD&A and other documents of public record, the Corporation has made assumptions regarding, among other things:

- future oil and natural gas production levels from IFR's properties and the prices obtained from the sales of such production;
- the level of future capital expenditure required to exploit and develop reserves; and
- the Company's ability to obtain financing on acceptable terms, as required.

The Corporation's actual results could differ materially from those anticipated in these forward-looking statements and information as a result of assumptions proving inaccurate and of both known and unknown risks as set forth below:

- 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;
- actions by governmental authorities, including regulatory, environmental and taxation policies; and
- fluctuations in foreign exchange or interest rates and stock market volatility
- ability to raise project finance capital from chartered banks

Other information

Additional information regarding International Frontier Corporation's reserves and other data are available on SEDAR at www.sedar.com