International Frontier Resources Corporation
Management's Discussion and Analysis
June 30, 2011

International Frontier Resources Corporation is engaged in the exploration for and development of oil and gas reserves in the Central Mackenzie Valley ("CMV"), Northwest Territories, Canada; in the Alderson area in Southern Alberta, Canada and in Glacier County, Northwest Montana, USA.

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 interim period ending June 30, 2011, as well as information concerning the Company's future outlook based on currently available information. The MD&A has been prepared by management in accordance with International Financial Reporting Standard 1 - First-time Adoption of International Financial Reporting Standards ("IFRS"), and with International Accounting Standard 34 - Interim Financial Reporting ("IAS 34"), as issued by the International Accounting Standards Board ("IASB"). Previously, the Company prepared its interim and annual financial statements in accordance with Canadian generally accepted accounting principles in effect prior to January 1, 2011 ("Canadian GAAP"). This MD&A contains forward looking statements, the definitions of which are defined herein.

The MD&A and the interim consolidated financial statements and accompanying notes have been prepared by management and approved by the Audit Committee and the Board of Directors on August 30, 2011. The interim consolidated financial statements have not been reviewed or audited on behalf of the shareholders by the Company's independent external auditors.

Corporate Update

Operations Review - Second Quarter 2011

Southern Alberta Basin
Glacier County - Northwest Montana

In Q2 the Company entered into a Purchase and Sale Agreement to purchase title to approximately 17,082 freehold acres ("fee acreage") located in the Blackfeet Reservation, Glacier County, NW Montana. The purchase price is US$3,183,133, in July the Company paid two-thirds of the purchase price (US$2,121,876) and the remaining one-third (US$1,061,261) is being held in our lawyers trust account until a title opinion has been completed. If the title opinion indicates that the vendors own less than 17,082 net acres, or more than 17,082 net acres, the purchase price will be adjusted accordingly using US$186.33 per net acre.

In August the Company entered into binding letter agreements to purchase title to 5,600 freehold acres (more or less) located in the Blackfeet Reservation, Glacier County. The Company has agreed to pay the vendors up to US$1,043,448. The Company will initially pay the vendors US$521,724 with the remaining 50% (US$521,724) due upon completion of a title opinion. If the title opinion indicates that the vendors own more, or less, than 5,600 net acres the purchase price will be adjusted accordingly using US$186.33 per net acre.

The majority of our fee acreage is currently under lease to Anschutz Exploration and Newfield Exploration. The leases reserve in favor of International Frontier gross over-riding royalties ranging from 12.50% to 18.75%. To extend a lease beyond the primary term the lessee must either drill a well, pool, or unitize the acreage to prove that production can be obtained from the acreage. If the lessee does not obtain production prior to expiry of the primary term the acreage reverts back to International Frontier (100%).

Based on field visits and scouting reports we believe that Anschutz Exploration (private), Newfield Exploration (NFX-Z) and Rosetta Resources (ROSE-Q) have drilled, in aggregate, twenty six discovery wells on the Blackfeet Reservation. Newfield and Rosetta announced that they have found oil in multiple geological formations in all of the vertical wells drilled to date. In Newfield's and Rosetta's Q1 & Q2 updates they have said the following;

Newfield

Drilled seven vertical wells, completed and placed on production two horizontal wells, and are preparing to drill an eighth vertical well. All wells have encountered oil over a very large areal extent. Newfield has increased its acreage position from 280,000 to 320,000 net acres in the play, located in Glacier County Montana. Multiple prospective geological formations throughout the acreage are planned for evaluation".

- Newfield recently announced that they are completing and fracture stimulating various geological formations in four wells, we believe the four wells are: Rumney (Sec 23-T37-R 11), Sacred Pipe (Sec 21-T 35-R9), Peacemaker (Sec 5-T33-R-6) and Buffalo Jump (Sec 28-T35-R11). Fracture stimulation and testing operations are currently being conducted.
- IFR owns fee acreage in townships, and in adjacent townships, to Newfield's wells.

Rosetta

- Confirmed significant oil hydrocarbons in place and over-pressured reservoirs
- 6 BBOE hydrocarbon resource in place (six billion barrels equivalent)
- 13 to 15 million barrels equivalent recoverable per 640 acres
- 11 vertical delineation wells drilled
- 7 horizontal wells planned for in 2011/2012
- 1,500 potential drilling locations based on 160 acre spacing

In a recent corporate presentation Rosetta provided base case well performance parameters which are;

- 250 IP BOEPD (gross initial production rate)
- 185,000 recoverable barrels equivalent (EUR gross – estimated ultimate recovery per 160 acres)
- 160-acre spacing
- $4 million well costs.

IFR owns fee acreage in 17 townships of the 24 townships identified on Rosetta's Q2 drilling map, the area covers 45 miles north-south and 30 miles east-west.

Anschutz

Production equipment has been installed on the Two-Medicine wells located in Sec 11- T31-R12. Field reports indicate that the Anschutz Browning well in Sec 8 – T32 – R11 has been drilled, cored and that casing was run to total depth (July 2011). State well licensing records indicate that Anschutz are re-entering previously drilled vertical wells to drill horizontal well-bore(s) on the White Calf T31 – R10 and Pine Ridge Sec 26 – T36 – R12 prospects. The Pine Ridge well commenced horizontal drilling operations in mid August.

- IFR holds a significant fee acreage position around the Browning, Pine Ridge and White Calf prospects and to a lesser extent around the Two Medicine wells.

The discovery of light oil in tight rock in Glacier County kicked off the Southern Alberta Basin Bakken play in southwest Alberta. The area is currently being explored by Argosy (GSY-T), Crescent Point (CPG-T), Murphy Oil (MUR-Z), Royal Dutch Shell (RDS-Z) Nexen (NXY-T), Dee Three (DTX-T) and Bowood-Legacy (BWD-TV) + (LEG – T). Dee Three and Murphy have announced initial production rates of +/-250 BOPD per well. It is worthy to note that Murphy Oil and Shell Oil have each licensed five wells within 12 miles of the Montana border.IFR holds fee acreage in township 37 which is adjacent to the Albertaborder and is within 6 to 16 miles of the Murphy and Shell wells.

The Company's fee acreage spans an area of 51 townships (township = 6 sq. miles) 95% of which is located within the Blackfeet Reservation. The acreage provides excellent exposure to an emerging light–tight- oil-resource play that offers multiple stacked zones, which include the Lodgepole, Bakken, Three Forks, Nisku and Cone horizons. As the Company's fee acreage does not expire we have numerous options available for future operations as the play is being de-risked by third parties.

Glacier County Drilling Activity

For the period January 1 to August 25, 2011 the Montana Department of Natural Resources and Conservation issued the following well licenses in Glacier County.

Operator	Well Location	Date	Depth Feet	Formation	IFR Fee * Approx. miles
Rosetta	Buffalo Lake 5-16-36-9	2/18/2011	7,419	Bakken	3.5
Anschutz	SW Browning 1-8-32-11HZ	2/18/2011	12,552	Cone Member	1.0
Newfield	Tribal Snowshoe 1-13-36-11 HZ	2/22/2011	11,639	Bakken	1.2
Newfield	Tribal Whitesands 1-19-31-9 HZ	2/22/2011	12,085	Bakken	3.0
Rosetta	Simonson 1-34-36-8	2/28/2011	6,600	Souris River	5.5
Newfield	Aimsback 1-7-33-7 HZ	4/11/2011	10,375	Bakken	0.5
Rosetta	Tribal Riverbend 4-7-36-9 HZ	5/6/2011	10,970	Bakken	3.5
Rosetta	Tribal Riverbend 13-12-37-9 HZ	6/6/2011	9,965	Bakken	1.2
Anschutz	Pine Ridge 2-26-36-13 HZ reentry	6/21/2011	13,538	Cone Member	1.5
Rosetta	Simonson Farms 1-34-36-8 HZ	6/23/2011	10,036	Bakken	2.5
Rosetta	Tribal Big Rock 29 – 37- 6 HZ	7/8/2011	9,028	Bakken	2.0
Anschutz	White Calf 1-31-31-10 HZ reentry	7/8/2011	12,046	Flood Member	0.5
Newfield	Meadowlark 1-26-36-11 HZ	8/17/2011	13,852	Devonian	2.2
Rosetta	Coyote Springs 18-34-6 HZ	8/17/2011	9,065	Bakken	0.05

HZ – Horizontal Well License * closest IFR fee acreage to the well location.
Note: For the most part operators drill a vertical well first to obtain rock properties and then re-enter the well at a later date to drill horizontal – lateral well bores.

Central Mackenzie Valley, NWT ("CMV")

On July 4, 2011 eleven licenses covering 2.2 million acres were awarded for work commitments of $536 million (see table).

Parcel	Company	Acres	Bid-Work Commitment	$/Acre
CMV 1	MGM Energy	204,210	$1,512,121	$7.40
CMV 2	Shell Canada *	217,320	$18,296,208	$84.19
CMV 3	Imperial Oil *	219,544	$21,500,003	$97.93
CMV 4	Husky Oil	216,825	$188,000,000	$867.05
CMV 5	MGM Energy	213,994	$1,502,502	$7.02
CMV 6	Husky Oil	215,061	$188,000,000	$874.17
CMV 7	Shell Canada *	215,266	$18,098,660	$84.00
CMV 8	ConocoPhillips*	216,200	$66,712,035	$308.56
CMV 9	MGM Energy	210,746	$2,021,212	$9.59
CMV 10	Shell Canada *	65,653	$7,049,269	$107.37
CMV 11	Imperial Oil *	223,951	$21,500,003	$96.00
Total		2,218,735	$536,000,000	$241.65 Average/Acre

*Denotes Mackenzie gas pipeline applicant.

Subsequent to the license awards "ConocoPhillips indicated that they are targeting a Canol shale play. The unconventional play will be more from a liquids prospective than from a gas perspective". In a Q2 conference call Husky said "it is attracted by the prospective nature of the land, which is 50 miles from the existing Enbridge pipeline which transports 34,900 barrels per day of light oil from Norman Wells to Zama in northwest Alberta. Husky's COO said his company has actively explored the Central Mackenzie Valley for more than a decade and has been involved in two discoveries".

Frontier's acreage in the Central Mackenzie Valley is comprised of 6,233 net tested acres, on which three Significant Discovery Licenses ("SDL") have been granted. The acreage held under the SDL's does not expire until all reserves are produced. In addition the Company holds a 25% interest in 236,732 (gross acres), 59,183 net un-evaluated acres. Husky Oil is the operator of the SDL lands and the un-evaluated acreage.

Alderson – southern *Alberta*

The Company operates five producing oil wells and an oil battery located in the Alderson area of southern Alberta. In Q2 a production optimization plan was completed resulting in production increasing from +/-25 BOPD in June 2010 to +/-40 BOPD in July/Aug 2011.

Mannyberries – south east Alberta

At the July 28th Alberta land sale the Company acquired an additional 480 acres for a cost of $24,000. The Company now holds a 100% interest in 1,120 acres. The acreage is prospective for oil in the Sawtooth and Sunburst channel sands. Negotiations are in progress to purchase a 3D seismic survey over the acreage.

Liquidity, capital resources and financing activities

Working Capital

At June 30, 2011, cash and cash equivalents were $5,986,140 (March 31, 2011 - $6,249,615) and working capital was $5,901,525 (March 31, 2011- $6,140,410). At June 30, 2011 the Company had restricted cash securing letters of credit in the amount of $374,305; 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 expired in May 2011 and the deposits in the amount of $266,365 and $68,750 respectively were forfeited.

The decrease in working capital at June 30, 2011 is the result of cash used to purchase freehold mineral titles located in the Glacier County, Northwest Montana.

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 certain working capital balance - 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 June 30, 2011, the Company's capital as defined above was approximately $6,072,160 (December 31, 2010 – $6,771,180).

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 v) income from leasing its Montana fee lands, vi) pooling or unitizing the Company's fee acreage in Montana.

Adoption of International Financial Reporting Standards

On January 1, 2011, the Company adopted IFRS for financial reporting purposes, using a transition date of January 1, 2010. The unaudited interim condensed financial statements for the three months ended June 30, 2011, including required comparative information, have been prepared in accordance with IAS 34, as issued by the IASB. Except as noted in the Summary of Quarterly Results section of this MD&A, 2010 comparative information has been prepared in accordance with IFRS. Reconciliations between Canadian GAAP and IFRS can be found in Note 17 of the unaudited interim condensed financial statements for the three months ended June 30, 2011.

The adoption of IFRS has not had an impact on the Company's operations, strategic decisions or cash flow. The most significant area of impact was the adoption of the IFRS accounting policies relating to property, plant and equipment, and decommissioning liabilities. Further information on the impact of converting to IFRS is provided in the Critical Accounting Policies section of this MD&A and in Notes 3 and 17 of the Company's unaudited interim condensed financial statements for the three months ended June 30, 2011.

Summary of First Quarter Results

Selected financial information:

	Three months ended June 30,		Six months ended June 30,	
	2011	**2010**	**2011**	**2010**
Statement of operations				
Sales volumes - BOE/ day (Canada)	34	30	30	29
Production volumes - BOE/ day (Canada)	35	25	31	27
Oil revenues, net (Canada)	$ 191,425	$ 151,825	$ 320,435	$ 303,720
Interest income from continuing operations	$ 4,725	$ 1,045	$ 18,100	$ 1,740
Net earnings (loss) and comprehensive loss				
Net earnings (loss) from continuing operations	$ (213,150)	$ (774,580)	$ (346,105)	$ (924,030)
Net loss for discontinued operations	$ -	$ (7,810)	$ -	$ (112,065)
Net earnings (loss) and comprehensive loss	$ (213,150)	$ (782,390)	$ (346,105)	$ (1,036,095)
Net earnings(loss) per share				
Net loss from continuing operations per share	$ (0.004)	$ (0.013)	$ (0.006)	$ (0.016)
Net loss from discontinued operations per share	$ -	$ -	$ -	$ (0.002)
Net loss per share	$ (0.004)	$ (0.013)	$ (0.006)	$ (0.018)
Cash flow				
Net cash provided (used in)				
Operating activities	$ (179,725)	$ (436,890)	$ (366,950)	$ (563,410)
Investing activities	$ (76,675)	$ (81,420)	$ (460,100)	$ (226,400)
Financing activities	$ -	$ 3,788,970	$ -	$ 3,788,970

	June 30, 2011	December 31, 2010	June 30, 2010
Balance sheet			
Assets of Continuing operations			
Exploration and evaluation assets	$ 6,850,175	$ 6,491,090	$ 8,212,165
Property and equipment	$ 948,975	$ 1,009,750	$ 1,818,250
Total assets	$ 14,543,495	$ 15,273,110	$ 18,109,400
Working capital	$ 5,901,525	$ 6,606,365	$ 7,294,650
Investing Activities			
For the three months ended			
Canada	$ 56,800	$ 298,225	$ 112,630
United States	$ 8,410	$ 27,120	$ -
Discontinued operations	$ -	$ -	$ -
	$ 65,210	$ 325,345	$ 112,630

Summary of Alderson Operations

	Three months ended		
	June 30, 2011	March 31, 2011	June 30, 2010
Sales volumes (Bbl/day)	34	26	30
Production volumes (Bbl/day)	35	27	25
Oil Sales	$ 242,315	$ 164,495	$ 182,300
Royalties	50,890	35,485	30,475
Net Revenues	191,425	129,010	151,825
Operating expenses	116,025	109,950	84,535
Net Income	$ 75,400	$ 19,060	$ 67,290
Oil Sales ($/BBL)	$ 79.34	$ 70.81	$ 67.34
Operating costs ($/BBL)	$ 37.99	$ 47.33	$ 30.95
Depletion per BOE	$ 10.42	$ 10.42	$ 17.88

- Sales volumes for the three months ended June 30, 2011 were 34 Bbl/day a 31.47% increase as compared to 26 Bbl/day for the first quarter of 2011 (Q-2 2010 – 30 Bbl/day)
- Increase in sales volumes in the second quarter of 2011 is due to increased production volumes in the quarter due to the pump change out on the 5-26 well in May 2011.
- Oil revenue in Q2, 2011 was $242,315 an increase of 47.31% as compared to Q1, 2011 at $164,495 (Q2, 2011 - $182,300)
- The increase in oil revenues can be attributed to the increase in sales volumes in the period coupled with a 12.05% increase in oil price (Q1, 2011 - $70.81 per barrel, Q2, 2011 - $79.34 per barrel)
- In Q2, 2011 the Company paid royalties of $50,890 a 43.41% increase as compared to $35,485 for Q1, 2011 (Q2, 2010 - $30,475). The increase in royalties is consistent with the increase in production in the period.
- Operating expenses in the second quarter of 2011 were $116,025 or $37.99 per Bbl which is consistent as compared to $109,950 or $47.33 in Q1, 2010 (Q2, 2010 - $84,535 or $30.95 per Bbl)

Interest income

- In Q2, 2011 interest income from short term investments was $4,725 (Q-1, 2011 - $13,375, Q2, 2010 - $1,045) the decrease was due to a decrease in cash invested in the period.

Depletion, depreciation and impairments

Depletion, depreciation and impairments for the three months ended June 30, 2011 and 2010 consist of the following

Depletion, depreciation and impairments	June 30, 2011	June 30, 2010
Depletion of oil and gas properties	$ 33,535	$ 40,655
Depreciation of equipment	805	765
	$ 34,340	$ 41,420

- Depletion of oil and gas properties for the three months ended June 30, 2011 was $33,535 or $10.42 per Bbl as compared to $26,005 or $10.42 per Bbl in Q1, 2011. (Q2 -2010 $40,655 or $17.55 per Bbl)
- At June 30, 2011 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 there was no impairment of oil and gas properties recorded in Q2, 2011 (Q2, 2010- $Nil)
- The carrying value of exploration and evaluation properties of $6,850,175 at June 30, 2011 (June 30, 2010 - $8,212,165, December 31, 2010 - $6,491,090) have been evaluated as of June 30, 2011 and it was determined that no costs had met the requirements to be transferred to property and equipment. These costs were also evaluated for impairment and it was determined that an impairment of $4,100 existed for the period ended June 30, 2011 (March 31, 2011 - $Nil, June 30, 2010 - $508,005)

General and administrative expenses

Three months ended:	June 30, 2011	March 31, 2011	June 30, 2010
Investor relations	$ 18,260	$ 4,625	$ 18,495
Filing and Transfer Fees	7,565	8,550	11,610
Professional Fees	50,230	6,140	6,190
Consulting Fees - gross	63,960	48,305	136,300
Consulting Fees - capitalized	-	-	(12,310)
Rent and office Costs	36,965	37,950	47,075
	$ 176,980	$ 105,570	$ 207,360

- In Q2, 2011 general and administrative expenses were $176,980, an increase of $71,410 or 67.64% as compared with $105,570 in Q1, 2011 (Q2, 2010 - $207,465).
- The increase in G&A in Q2, 2011 can be attributed to costs associated with the Company's year end audit and costs incurred for the annual general meeting.
- The decrease in G&A in 2011 is due to lower consulting and professional fees in the year.

Net loss

Three months ended:		**Q-2 2011**		**Q-1 2011**		**Q-2 2010**
Net loss from continuing operations	$	(213,150)	$	(132,955)	$	(774,580)
Net loss from discontinued operations		-		(1,185)		(7,810)
Consolidated net loss	$	(213,150)	$	(3,633,035)	$	(782,390)
Loss per share						
Continuing operations	$	(0.004)	$	(0.002)	$	(0.013)
Discontinued operations	$	(0.00)	$	(0.00)	$	(0.00)
Loss per share	$	(0.004)	$	(0.002)	$	(0.013)

- The decreased loss in Q2, 2011 as compared with Q2, 2010 is the result of an impairment of exploration and evaluation assets of $507,900 at June 30, 2010 as compared to $4,100 at June 30, 2011.

Summary of Quarterly Results

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

Quarter ended:	**Sept 30, 2009**	**Dec 31, 2009**	**Mar 31, 2010**	**June 30, 2010**
Statement of operations				
Sales volumes - BOE/ day (Canada)	35	36	28	30
Production volumes - BOE/ day (Canada)	37	34	33	25
Oil revenues, net (Canada)	$ 162,280	$ 180,885	$ 148,225	$ 151,825
Net earnings (loss) and comprehensive loss				
Net earnings (loss) from continuing operations	$ (1,682,195)	$ (2,294,220)	$ (165,860)	$ (651,115)
Net loss for discontinued operations	$ (1,809,830)	$ (6,764,310)	$ (104,255)	$ (7,810)
Net earnings (loss) and comprehensive loss	$ (3,492,025)	$ (9,058,530)	$ (270,115)	$ (658,925)
Net earnings(loss) per share				
Net loss from continuing operations per share	$ (0.03)	$ (0.04)	$ (0.04)	$ (0.01)
Net loss from discontinued operations per share	$ (0.03)	$ (0.00)	$ (0.11)	$ -
Net loss per share	$ (0.06)	$ (0.04)	$ (0.15)	$ (0.01)
Balance Sheet				
Total assets	$29,980,890	$20,972,600	$ 20,719,095	$ 19,708,385
Working capital	$ 4,279,660	$ 7,865,635	$ 7,646,280	$ 7,310,610
Refundable Deposits	$ 925,060	$ 640,670	$ 640,670	$ 640,670
Funds flow from operations	$ (188,805)	$ (146,220)	$ (126,625)	$ (436,995)

Quarter ended:	**Sept 30, 2010**	**Dec 31, 2010**	**March 31, 2011**	**June 30, 2011**
Statement of operations				
Sales volumes - BOE/ day (Canada)	26	28	26	34
Production volumes - BOE/ day (Canada)	31	28	27	35
Oil revenues, net (Canada)	$ 111,445	$ 145,940	$ 122,665	$ 191,425
Net earnings (loss) and comprehensive loss				
Net earnings (loss) from continuing operations	$ (100,335)	$ (5,192,815)	$ (133,070)	$ (213,150)
Net loss for discontinued operations	$ -	$ (1,185)	$ -	$ -
Net earnings (loss) and comprehensive loss	$ (100,335)	$ (5,194,000)	$ (133,070)	$ (213,150)

Quarter ended:	**Sept 30, 2010**	**Dec 31, 2010**	**March 31, 2011**	**June 30, 2011**
Net earnings(loss) per share				
Net loss from continuing operations per share	$ -	$ (0.09)	$ (0.002)	$ (0.004)
Net loss from discontinued operations per share	$ -	$ (0.00)	$ -	$ -
Net loss per share	$ -	$ (0.09)	$ (0.002)	$ (0.004)
Balance Sheet				
Total assets	$19,531,265	$15,283,980	$ 15,000,920	$ 14,543,495
Working capital	$ 7,186,425	$ 6,457,185	$ 6,140,410	$ 5,901,525
Refundable Deposits	$ 640,670	$ 640,670	$ 640,670	$ 374,305
Funds flow from operations	$ (77,935)	$ (251,820)	$ (187,010)	$ (179,725)

(1) Results reported for 2011 are in accordance with IFRS.
(2) Results reported for 2010 and 2009 are in accordance with Canadian GAAP and are not to be compared to the results presented in accordance with IFRS.

Financial Instruments

As disclosed in Note 3 to the unaudited condensed consolidated interim financial statements at June 30, 2011, 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 June 30, 2011 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.

	June 30, 2011		**December 31, 2010**	
	Carrying Value ($)	**Fair Value ($)**	**Carrying Value ($)**	**Fair Value ($)**
Financial assets:				
Receivables	$ 59,715	$ 59,715	$ 111,010	$ 111,010
Total financial assets	$ 59,715	$ 59,715	$ 111,010	$ 111,010
Financial liabilities				
Payables and accruals	$ 202,525	$ 202,525	$ 607,600	$ 607,600
Total financial liabilities	$ 202,525	$ 202,525	$ 607,600	$ 607,600

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 June 30, 2011 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 June 30, 2011 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
$ 59,715	$ 54,655	$ 5,060	$ -	$ -

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. 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 c ash flow of the Company during the period ended June 30, 2011.

d) **Foreign currency risk:** The Company is exposed to foreign currency risk as the Company holds cash and cash equivalents on hand that are denominated in United States dollars. At June 30, 2011, the carrying amount of the Company's foreign currency denominated net monetary assets was approximately C$307,955 Assuming all other variables remain constant, a fluctuation of one cent in the exchange rate of the Canadian dollar to the U.S. dollar would not result in a material change in income

e) **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 June 30, 2011, the Company's accounts payable and accrued liabilities were $486,595 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
$ 202,525	$ 86,450	$ 19,815	$ (14,260)	$ 110,520

Investing Activities

For the three months ended	June 30, 2011	March 31, 2011	June 30, 2010
Canada	$ 56,800	$ 6,595	$ 112,630
United States	8,410	291,500	-
Discontinued operations	-	-	-
	$ 65,210	$ 298,095	$ 112,630

- Capital expenditures for the period ending June 30, 2011 were $363,185 of which $299,910 is related to a deposit to purchase mineral titles on freehold lands located in Glacier County, Northwest Montana, USA and $63,395 is related to geological and geophysical consulting fees in the Central Mackenzie Valley, NWT.

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 and subsequent payments calculated at 4% of the Company's annual production revenue less transportation and processing fees.

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 June 30, 2011 are provided below, these costs are included in general and administrative expenses on the consolidated condensed statements of operations and comprehensive loss at June 30, 2011:

- Compensation paid to executive officers was $39,000 (2010 - $132,000) of which $Nil (2010 - $18,000) was capitalized to property and equipment for the period ending June 30, 2011.
- At June 30, 2011 royalties of $15,655 (2010 - $84,510) were paid to officers and consultants pursuant to the Company's Royalty Incentive Plan. Royalties paid in the period ended June 30, 2010 include an amount of $75,795 covering the sale of the Company's North Sea operation.

Other Items

Outstanding shares, options and warrants

The Company's share capital structure is as follows:

As of:	June 30, 2011	August 30, 2011
Common shares outstanding	59,578,965	59,578,965
Options outstanding	5,231,500	5,231,500
Fully diluted	64,810,465	64,810,465

Additional details on the shares, options and warrants outstanding at June 30, 2011 are available in the Notes to the June 30, 2011 interim consolidated condensed financial statements.

Accounting Policies and Estimates

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

Adoption of IFRS

The Company has prepared its interim condensed consolidated financial statements for the three months ended June 30, 2011 in accordance with IAS 34 and IFRS 1 – *First-time Adoption of IFRS*. Previously, the Company prepared its financial statements in accordance with Canadian

GAAP. The adoption of IFRS has not changed the Company's business activities or actual cash flow; however, it has resulted in adjustments to the Company's financial statements.

The areas that were most impacted by the transition to IFRS are accounting for exploration and evaluation assets, accounting for property, plant and equipment, asset impairment testing, and accounting for income taxes. Refer to Note 3 of the Company's unaudited interim consolidated condensed financial statements for the Company's detailed IFRS accounting policies.

In order to allow the users of the financial statements to better understand the impact of the change to IFRS, the Company's Canadian GAAP balance sheets at January 1, 2010, March 31, 2010 and December 31, 2010, and the Company's consolidated statements of operations and comprehensive loss for the three months ended March 31, 2010 and for the year ended December 31, 2010 have been reconciled to IFRS.

The following provides a summary reconciliation of the Company's 2010 Canadian GAAP and IFRS results. Further discussion of the significant IFRS accounting policy changes can be found in Note 17 of the Company's Interim Consolidated Condensed Financial Statements.

	2010				
Summary of Net Earnings Reconciliation	**Q-1**	**Q-2**	**Q-3**	**Q-4**	**2010**
Net loss - GAAP	$ (270,115)	$ (658,925)	$ (100,335)	$ (5,194,000)	$ (6,223,375)
Additions (deductions):					
Exploration and evaluation costs	24,450	167,080	2,000	(1,624,635)	(1,431,105)
Depletion	(30,100)	(33,500)	(13,700)	(144,150)	(221,450)
Adjust investment in subsidiary to equity method of consolidation	(105)	(105)	(105)	(23,845)	(24,160)
Impairment of property and equipment	-	-	-	240,635	240,635
Decommissioning liabilities - accretion	(9,410)	(10,010)	(10,900)	(11,445)	(41,765)
	(15,165)	123,465	(22,705)	(1,563,440)	(1,477,845)
Net loss - IFRS	$ (254,950)	$ (782,390)	$ (77,630)	$ (3,630,560)	$ (4,745,530)

Recent Accounting Pronouncements

All accounting standards effective for periods beginning on or after January 1, 2011 have been adopted as part of the transition to IFRS. As of January 1, 2013, the Company will be required to adopt IFRS 9 - *Financial Instruments*, which is the result of the first phase of the IASB's 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. The adoption of this standard is not expected to have a material impact on the Company's 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.

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;
- treatment under governmental regulatory regimes and tax laws and;
- third party drilling, testing and production results.

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;
- the Company's ability to obtain financing on acceptable terms, as required and;
- Results of wells drilled by third parties in the vicinity of the Corporations acreage.

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, first nations, 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 is available on SEDAR at www.sedar.com