International Frontier Resources Corporation
Management's Discussion and Analysis
June 30, 2013

International Frontier Resources Corporation is an independent Canadian public company, the principle business of which is to acquire, develop, exploit and produce oil and natural gas in the Central Mackenzie Valley, Northwest Territories, Canada, northwest Montana USA and in south east Alberta.

The following is management's discussion and analysis ("MD&A") of International Frontier Resources Corporation's ("International Frontier" or "IFR" or 'Frontier' or the "Corporation" or the "Company") operating and financial results for the period ending June 30, 2013, 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 June 30, 2013 in accordance with IFRS and should be read in conjunction with the audited financial statements as at December 31, 2012 together with accompanying notes, the Statement of Reserves Data and Other Oil and Gas Information contained in the Company's annual 51-101 dated December 31, 2012. This MD&A contains forward-looking statements, the definitions of which are defined herein.

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 indicate.

Business Overview

International Frontier Resources Corporation is an independent Canadian public company, the principle business of which is to acquire, develop, exploit and produce oil and natural gas in the Central Mackenzie Valley, Northwest Territories, Canada, northwest Montana USA and in south east Alberta. A summary for the period ending June 30, 2013 is as follows.

Central Mackenzie Valley, NWT ("CMV")

As of the date of this MD&A the Company has participated in nine exploration wells in the CMV, the Company was fully carried in three wells and partially carried in a fourth well. Hydrocarbons were encountered in four wells and five wells were abandoned and the drill sites restored. In addition the Company participated in three aero-mag surveys and four proprietary 2D seismic surveys. The Company holds an interest in three Significant Discovery Licenses ("SDL") and three Freehold parcels located in the Sahtu region of the CMV, a summary of the Company's discoveries and un-evaluated acreage is as follows:

Summit Creek – 11,380 acres

The well *Husky et al Summit Creek B-44-64-30-125-45* lies in the foothills of the Mackenzie Mountains, 110 kilometers south of the town of Norman Wells. The B-44 well was drilled to a depth of 10,050 feet cased and suspended. Production testing of the *Summit Creek B-44* well confirmed several productive intervals within a gross hydrocarbon column of over 600 feet in the Devonian Formation. Two separate intervals, encompassing net pay of 255 feet, were flow tested, each zone produced at rates of approximately 10 MMCF/D of natural gas and 3,000 barrels per day of condensate.

The Company's independent reserve evaluator assigned contingent gross resources of 38.7 billion cubic feet of gas and six million barrels of oil (Best Case 42% recovery) and a high case of 163 billion cubic feet of gas and 27 million barrels of condensate (61% recovery).

Partners in the Summit Creek SDL are Husky Oil Operations (operator) 59.28%, Taqa North 32.50% and IFR 8.2112%.

Stewart Lake – 19,990 acres

The well *Husky et al Stewart Lake D-57-64-20-125-15* is located 30 kilometers south of the Summit Creek SDL. The well was drilled on TDL freehold parcel M-38 to a total depth of 10,322 feet, open hole tested, cased and suspended. The D-57 well tested sweet dry natural gas at a rate of 5 MMCF/D (un-stimulated) from two separate reservoirs of Cretaceous-aged sandstones. The structure covers nine crown sections on which two SDL's have been granted; TDL freehold parcel M-38 is located in the middle of the two SDL's.

Based on IFR's acreage position in the Stewart discovery area the Company estimates it holds 16.50% of the SDL reserves. The Company's independent reserve evaluator assigned contingent gross resources for the Stewart discovery SDL area of 20 billion cubic feet (best estimate) and 63 billion cubic feet (high estimate).

Partner's in the Stewart Lake SDL's are Husky Oil Operations (operator) 59.28%, Taqa North 32.50% and IFR 8.221%. Partners in TDL freehold parcel M-38 are Husky Oil Operations (operator) 75% and IFR 25%.

Sah Cho L-71 TDL Parcel M37 – 16,987 acres

The *Husky et al Sah Cho L-71* well was drilled and cased to a total depth of 12,100 feet. The primary objectives, the Arnica and Hume zones encountered gas and water. Prospective zones that have not yet been tested include the Cretaceous age Arctic Red and the Little Bear sands.

Partners in the *Sah Cho L-71* well and in TDL freehold parcel M-37 are Husky Oil Operations (operator) 75% and IFR 25%.

TDL Freehold Parcel M39 – 11,584 acres

Freehold parcel M-39 is located within the boundary of Exploration License EL-472; the license was awarded to Imperial Oil 50% and ExxonMobil 50% at the 2011 land sale for a work commitment of $21.5 million. Parcel M-39 is held Husky Oil Operations (operator) 75%, IFR 25%.

The Summit Creek and Stewart Lake acreage is held under Significant Discovery Licenses therefore it does not expire until all reserves are produced from the SDL areas. The TDL Freehold Leases can be renewed each year by paying annual rentals in the amount of $103,000 (net).

Devonian Shale Plays – Sahtu Region CMV

As of the date of this MD&A five vertical pilot wells have been drilled to evaluate the Devonian-age Canol and Bluefish shale Formations. The pilot wells were drilled to assess the viability of developing the target zone with horizontal drilling and multi-stage-fraccing technology. The Canol is the source rock that generated oil in the Norman Wells oilfield (270+ million barrels recoverable) and hydrocarbons in the Company's Summit Creek discovery. Interpretation of the Company's proprietary seismic and geological data indicates that the Canol and Bluefish shale's are prospective exploration targets in the Company's cased well bores and un-evaluated acreage. Horizontal drilling and multi-stage-fraccing technology was not developed when the Company participated in nine exploration wells in the Sahtu region.

At the 2011 & 2012 land sales thirteen exploration licenses were awarded for combined work program bids of $627 million. To date exploration programs have been conducted on three licenses. On the remaining ten licenses, on which no exploration work has been reported to the National Energy Board, Imperial Oil (50%) ExxonMobil (50%) hold two licenses with combined work programs of $42.5 million, Shell Canada (100%) has four licenses with combined work programs of $119 million, Shell Canada & MGM Energy hold three licenses with combined work programs of $18.5 million and MGM Energy (100%) holds one license with a work program of $2.2 million. The initial term of an exploration license is 5-years, to extend a license for a second term of 4-years the licensee must have incurred qualified expenditures equal to the work program bid and have drilled a minimum of one well on the license.

A summary of exploration activity in the emerging Devonian light oil shale play in the Sahtu region of the Central Mackenzie Valley is as follows.

EL-463 Husky Oil – 100%
Husky drilled, cored, fracced and production tested the Canol Formation in the Little Bear N-09 well. Well data is on confidential status.

EL-462 Husky Oil – 100%
Husky drilled, cored, perforated and production tested the Canol Formation in the Little Bear H-64 well. The N-09 well was not fracture stimulated, well data is on confidential status.

Husky acquired a 220 square kilometer 3D seismic survey the majority of which covers EL-463.

EL-470 ConocoPhillips – 100%
ConocoPhillips drilled and cored the Canol Formation in two vertical wells, results are on confidential status. In Q1, 2013 ConocoPhillips submitted an application to the regulatory authorities to horizontally drill and conduct multi-stage fracturing operations for two wells in Q1, 2014 the application was approved in July 2013. The primary target zone for the wells is the Canol Formation.

EL-466B MGM Energy – MGM- 62.50% Shell Oil – 32.50%
The East Mackay I-78 well was drilled, cored, fracced and production tested. MGM reported encountering oil in the Canol Formation. Well data is on confidential status.

2013 CMV Annual Land Sale
The 2012-2013 Call for Bids was announced on May 18, 2013, bids due on September 17, 2013, license awards should be announced before the end of September. In July the Department of Indian and Northern Affairs removed one nominated area from the land sale, as a result the Call for Bids now only covers one license in the Sahtu area, the remaining five parcels are located north-west of Norman Wells close to the Yukon border.

Southern Alberta Basin ("SAB") - Glacier County, NW Montana

The Company owns Mineral Titles on 15,200 un-evaluated freehold acres ("Fee Acreage") located on the Blackfeet Reserve ("Reserve") in Glacier County, NW Montana. Glacier County sits on the south end of the Southern Alberta Basin ("SAB") where industry has been drilling horizontal-multi-stage-fracced wells to evaluate various tight-light-oil formations.

Approximately 90% of the Company's Fee Acreage is under lease to Anschutz Exploration, Newfield Exploration and Rosetta Resources. The leases reserve in favor of IFR royalties ranging from 12.50% to 18.50%. The average term remaining on the Company's existing leases is 2.5 years, when a lease expires the acreage reverts back to IFR resulting in IFR holding a 100% net revenue lease.

As of the date of this MD&A 18 horizontal wells and 14 vertical stratigraphic pilot wells have been drilled within close proximity to the Company's Mineral Title acreage.
The Montana Board of Oil & Gas Conservation reported oil was encountered in the Bakken, Nisku, Second White Specs (Cone), Sun River Dolomite and Virgelle Formations for well drilled in 2010 to 2012. Production data reported to date indicates non-commercial flow rates from each formation. Well data is currently classified as confidential.

On the Alberta side of the SAB play Dee Three Exploration has a significant Bakken discovery in the Ferguson area located 12 miles north of the Montana border. Further north, in the Monarch area Torc Oil & Gas have discoveries producing an average of 350 BOPD (120 day IP). Operators on the Alberta side of the play report drilling longer horizontal sections and using different fraccing techniques than the operators on the Montana side of the play. The majority of the well data in Alberta and Montana is listed as confidential, well data begins coming off confidential status in 2014.

South East Alberta

The Company owns a 100% interest in five oil wells and an oil battery in the Alderson area; the wells produce 35 – 40 BOPD from the Mannville Formation. Production from the Alderson field is in line with the Company's projections.

The Company owns a 100% interest in 1,120 acres located in the Manyberries area; the leases expire in 2016 – 2017. The Company is seeking a partner to participate in a 3D seismic survey to identify drilling locations.

Liquidity, capital resources and financing activities

Working Capital

At June 30, 2013 cash and cash equivalents were $3,067,225 (March 31, 2013 - $3,214,165, December 31, 2012 - $3,456,380) and working capital was $2,939,080 (December 31, 2012 - $3,018,180). The decrease in working capital at June 30, 2013 is the result of capital expenditures of $63,085 in the CMV for annual lease rentals and $163,100 to complete the acquisition of Freehold Mineral Titles in NW 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 on-going basis and believes that its approach, given the relative size of the Company is reasonable.   As at June 30, 2013, the Company's capital as defined above was approximately $2,754,020 (March 31, 2013 - $2,849,295, December 31, 2012 – $2,921,040).

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, v) issuing new shares iv) obtaining debt financing, or a combination of these possible steps.

Summary of Second Quarter Results

Selected financial information:

	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Statement of operations				
Sales volumes - BOE/ day (Canada)	37	39	38	40
Production volumes - BOE/ day (Canada)	36	41	38	41
Oil revenues, net (Canada)	$ 189,595	$ 184,450	$ 356,515	$ 406,710
Interest income from continuing operations	$ 6,680	$ 6,980	$ 13,095	$ 14,570
Net loss and comprehensive loss	$ (38,335)	$ (62,165)	$ (69,870)	$ (115,840)
Net loss per share				
Net loss per share	$ (0.001)	$ (0.001)	$ (0.001)	$ (0.002)
Cash flow				
Net cash provided (used in)				
Operating activities	$ (82,980)	$ (100,395)	$ (151,410)	$ (128,350)
Investing activities	$ (63,960)	$ (209,095)	$ (237,745)	$ (228,070)

	June 30, 2013	December 31, 2012	June 30, 2012
Balance sheet			
Assets of Continuing operations			
Exploration and evaluation assets	$ 9,461,065	$ 9,374,950	$ 9,864,790
Property and equipment	$ 1,031,500	$ 1,101,270	$ 1,078,370
Total assets	$ 13,999,290	$ 14,282,915	$ 15,074,790
Working capital	$ 2,939,080	$ 3,018,180	$ 2,926,350
Investing Activities			
For the three months ended			
Canada	$ 52,350	$ 25,530	$ 53,175
United States	$ 11,610	$ 37,340	$ 19,725
	$ 63,960	$ 62,870	$ 72,900

Summary of Alderson Operations

	Three months ended			Six months ended	
	June 30, 2013	March 31, 2013	June 30, 2012	June 30, 2013	June 30, 2012
Sales volumes (Bbl/day)	37	40	39	38	40
Production volumes (Bbl/day)	36	39	41	38	41
Oil Sales	$ 248,055	$ 217,775	$ 245,575	$ 465,830	$ 538,595
Royalties	58,460	50,855	61,125	109,315	131,885
Net Revenues	189,595	166,920	184,450	356,515	406,710
Operating expenses	101,490	81,505	114,035	182,995	216,125
Net Income	$ 88,105	$ 85,415	$ 70,415	$ 173,520	$ 190,585
Oil Sales ($/BBL)	$ 73.52	$ 60.56	$ 68.50	$ 66.83	$ 74.22
Operating costs ($/BBL)	$ 30.88	$ 21.92	$ 31.81	$ 26.25	$ 29.78
Depletion per BOE	$ 11.14	$ 10.99	$ 10.79	$ 11.06	$ 10.95

- Sales volumes in Q2, 2013 were 37 Bbl/day, a 7.50% decrease as compared to 40 Bbl/day in Q1, 2013 (Q2, 2012 – 39 Bbl/day).
- Decrease in sales volumes in Q2, 2013 is due to lower production volumes resulting from wells being shut-in for maintenance at Alderson. Alberta.
- Oil revenue in Q2, 2013 was $248,055 an increase of 13.90% or $30,280 as compared to Q1, 2013 due to a 21.40% increase in oil price.
- In Q2, 2013 the Company paid royalties of $58,460 an increase of $7,605 or 14.95% as compared to $50,855 in the previous quarter.
- Operating expenses in Q2, 2013 were $101,490 or $30.88 per Bbl an increase of $19,985 as compared to Q1, 2013 (Q2, 2012 - $114,035).
- Higher operating costs in Q2, 2013 were due to work-over costs incurred in the Alderson Field.

Interest income

- In Q2, 2013 interest income from short-term investments was $6,680 (Q1, 2013 - $6,415, Q2, 2012 - $6,980).

Accretion of asset retirement obligation

- Accretion of asset retirement obligations in Q2, 2013 was $4,415 (Q1, 2013 - $3,985, Q2, 2012 - $3,690).

Depletion, depreciation and impairments

For the three months ended:	**June 30, 2013**	**March 31, 2013**	**June 30, 2012**
Depletion of oil and gas properties	$ 36,785	$ 39,000	$ 40,360
Amortization of Alderson Battery	2,495	2,495	2,495
Depreciation of equipment	265	290	325
	$ 39,545	$ 41,785	$ 43,180

- Depletion of oil and gas properties in Q2, 2013 was $36,785 or $11.14 per Bbl, which is consistent to $39,000, or $10.99 per Bbl in Q1 - 2013. (Q2 -2012 $40,360 or $10.79 per Bbl).

- At June 30, 2013 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, 2012. As a result there was a $Nil impairment recorded in Q2, 2013 (Q1 2013 - $Nil, Q2, 2012- $Nil)
- The carrying value of exploration and evaluation assets at June 30, 2013 have been evaluated 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 no impairment existed for the period ended June 30, 2013.

General and administrative expenses

Three months ended:	June 30, 2013	March 31, 2013	June 30, 2012
Investor relations	$ 8,520	$ -	$ 8,990
Filing and Transfer Fees	7,130	6,685	6,795
Professional Fees	10,180	700	10,095
Consulting Fees	55,125	56,165	53,605
Rent and office Costs	41,640	32,620	36,365
	$ 122,595	$ 96,170	$ 115,850

- General and administration expenses in Q2, 2013 were $122,595 a 27.48% increase as compared to the previous quarter. Increased costs in Q2, 2013 are attributed to expenses incurred for the Company's annual general meeting.

Net loss

Three months ended:	Q-2 2013	Q-1 2013	Q-2 2012
Net loss from continuing operations	$ (38,335)	$ (31,535)	$ (62,165)
Loss per share			
Loss per share	$ (0.001)	$ (0.001)	$ (0.001)

- The net loss in Q2, 2013 was $38,335 which is consistent with the previous quarter and in line with the Company's budget.

Summary of Quarterly Results

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

Quarter ended:	Sept 30, 2011	Dec. 31, 2011	March 31, 2012	June 30, 2012
Statement of operations				
Sales volumes - BOE/ day (Canada)	48	39	40	39
Production volumes - BOE/ day (Canada)	44	41	40	41
Oil revenues, net (Canada)	$ 242,630	$ 223,440	$ 222,260	$ 184,450
Net earnings (loss) and comprehensive loss	$ (29,550)	$ (297,685)	$ (53,675)	$ (62,165)
Net earnings(loss) per share				
Net loss per share	$ (0.000)	$ (0.005)	$ (0.001)	$ (0.001)
Balance Sheet				
Total assets	$ 14,462,870	$ 15,727,840	$ 15,625,940	$ 15,074,790
Working capital	$ 4,375,000	$ 3,065,520	$ 3,014,555	$ 2,926,350
Refundable Deposits	$ 374,305	$ 374,305	$ 305,555	$ -
Funds flow from operations	$ (1,820)	$ 139,525	$ (27,955)	$ (100,395)

Quarter ended:	Sept 30, 2012	Dec. 31. 2012	March 31, 2013	June 30, 2013
Statement of operations				
Sales volumes - BOE/ day (Canada)	33	41	40	37
Production volumes - BOE/ day (Canada)	32	40	39	36
Oil revenues, net (Canada)	$ 155,750	$ 189,930	$ 166,920	$ 189,595
Net earnings (loss) and comprehensive loss	$ (136,755)	$ (302,905)	$ (31,535)	$ (38,335)
Net earnings(loss) per share				
Net loss per share	$ (0.002)	$ (0.005)	$ (0.001)	$ (0.001)
Balance Sheet				
Total assets	$ 14,916,380	$ 14,282,915	$ 14,084,895	$ 13,999,260
Working capital	$ 2,775,875	$ 3,018,180	$ 2,998,075	$ 2,939,725
Funds flow from operations	$ (59,385)	$ (315,130)	$ (68,430)	$ (82,980)

Financial Instruments

As disclosed in Note 3 to the unaudited condensed interim financial statements at June 30, 2013 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, 2013 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, 2013		Fair Value Measurements	
	Carrying Value ($)	Fair Value ($)	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)
Financial assets:				
Loans and receivables				
Receivables	$ 92,405	$ 92,405	$ -	$ 92,405
Deposits	$ 254,440	$ 254,440	$ -	$ 254,440
Held for trading				
Cash and cash equivalents	$ 3,067,225	$ 3,067,225	$ 3,067,225	$ -
	$ 3,414,070	$ 3,414,070	$ 3,067,225	$ 346,845
Financial liabilities				
Measured at amortized costs				
Payables and accruals	$ 302,905	$ 302,905	$ -	$ 302,905
Total financial liabilities	$ 302,905	$ 302,905	$ -	$ 302,905

	December 31, 2012		Fair Value Measurements	
	Carrying Value ($)	Fair Value ($)	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)
Financial assets:				
Loans and receivables				
Receivables	$ 83,095	$ 83,095	$ -	$ 83,095
Deposits	$ 253,175	$ 253,175	$ -	$ 253,175
Held for trading				
Cash and cash equivalents	$ 3,456,380	$ 3,456,380	$ 3,456,380	$ -
	$ 3,792,650	$ 3,792,650	$ 3,456,380	$ 336,270
Financial liabilities				
Measured at amortized costs				
Payables and accruals	$ 523,700	$ 523,700	$ -	$ 523,700
Total financial liabilities	$ 523,700	$ 523,700	$ -	$ 523,700

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, 2013 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, 2013 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
$ 92,405	$ 89,055	$ 3,350	$ -	$ -

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 cash flow of the Company during the period ended June 30, 2013.

d) **Foreign currency risk:** The Company is exposed to risks arising from fluctuations in foreign currency exchange rates, primarily between Canadian and U.S. dollars. The Company does not utilize any foreign currency based derivatives. In order to manage this risk and to defer the realization of any resulting currency loss from converting Canadian dollars to US dollars, the Company retains cash balances in both US and Canadian dollars.

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, 2013 the Company's accounts payable and accrued liabilities were $302,905 most 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
$ 302,905	$ 44,525	$ 675	$ -	$ 257,705

Investing Activities

Exploration and evaluation assets

For the three months ended	June 30, 2013	March 31, 2013	June 30, 2012
Canada	$ 52,350	$ 10,735	$ 19,725
United States	11,610	11,420	28,345
	$ 63,960	$ 22,155	$ 48,070

- Capital expenditures in Q2, 2013 were $63,960 (Q1, 2013 - $22,155, Q2, 2012 - $48,070) of which 82% (Q1, 2013 – 48%, Q2, 2012 – 41%) is related to activities in Canada and $11,610 or 18% (Q1, 2013 – 52%, Q2, 2012 – 59%) is related to the costs to acquire mineral titles in Northwest Montana, USA.

Property and equipment

- In Q2, 2013 the Company incurred $Nil (Q1, 2013 - $11,560, Q2, 2012 - $28,345) in costs on the Alderson oil battery.

Obligations

- The Company is party to an agreement to lease its premises until December 31, 2014. The annual rent is $43,400 plus occupancy costs for 2013 & 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 June 30, 2013, payout of 100% of cumulative annual capital

expenditures had been reached on the Alderson oil property and subsequent payments are 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, 2013 are provided below, these costs are included in general and administrative expenses on the condensed statements of operations and comprehensive loss at June 30, 2013:

- Compensation paid to executive officers was $62,500 (June 30, 2012 - $62,500) in salaries and $46,550 (June 30, 2012 - $46,550) in consulting fees.
- At June 30, 2013 royalties of $18,100 (June 30, 2012 - $21,125) were paid to officers, directors and consultants pursuant to the Company's Royalty Incentive Plan.

Other Items

Outstanding shares, options and warrants

The Company's share capital structure is as follows:

As of:	June 30, 2013	August 28, 2013
Common shares outstanding	59,578,965	59,578,965
Options outstanding	5,181,500	5,181,500
Fully diluted	64,760,465	64,760,465

Additional details on the shares, options and warrants outstanding at June 30, 2013 are available in the Notes to the June 30, 2013 condensed interim financial statements.

Changes in accounting policies

Effective January 1, 2013, the Company has adopted the following new IFRS standards and amendments.

1. Presentation of Financial Statements

The Company has applied the amendments to IAS 1, "Presentation of Financial Statements" ("IAS 1"). The amendments require items within OCI to be grouped into two categories: (1) items that will not be subsequently reclassified to profit or loss or (2) items that may be subsequently reclassified to profit or loss when specific conditions are met. The amendment has been applied retrospectively and, as such, the presentation of items in OCI has been modified. The application of the amendment to IAS 1 did not result in any adjustments to other comprehensive income or comprehensive income.

2. Offsetting Financial Assets and Financial Liabilities

The amendments to IFRS 7 "Financial Instruments: Disclosures" develop common disclosure requirements for financial assets and financial liabilities that are offset in the financial statements, or that are subject to enforceable master netting arrangements or similar agreements. The adoption of these amendments does not have any impact to the Company's financial statements, other than increasing the level of annual disclosures.

3. Reporting Entity

- IFRS 10, "Consolidated Financial Statements", replaces the consolidation requirements in SIC-12, "Consolidation – Special Purpose Entities" and a portion of IAS 27. IFRS 10 builds on existing principles by identifying the concept of control as the determining factor in whether an entity should be included within the consolidated financial statements of the parent company and provides additional guidance to assist in the determination of control where this is difficult to assess. The retrospective application of this standard does not have any impact on the Company's financial statements.
- IFRS 11, "Joint Arrangements", focuses on the rights and obligations of the joint arrangement, rather than its legal form and requires joint arrangements to be classified either as joint operations or joint ventures. For joint operations, a company recognizes its share of assets, liabilities, revenues and expenses of the joint operation. To account for interest in its jointly controlled entity Sidox Chemicals Canada Ltd., the equity method is used. The retrospective application of this standard does not have any impact on the Company's financial statements.
- IFRS 12, "Disclosure of Interest in Other Entities", is a comprehensive standard on disclosure requirements for all forms of interests in other entities, including joint arrangements, associates, structure entities and other off balance sheet interests. The retrospective application of this standard does not have any impact on the Company's financial statements.

4. Fair Value Measurements

IFRS 13, "Fair Value Measurement", provides a consistent definition of fair value, establishes a single framework for determining fair value and introduces requirements for disclosures related to fair value measurement. The measurement of the fair value is based on assumptions that market participants would use when pricing the asset or liability under current market conditions including assumptions about risks. The prospective adoption of this standard does not have any impact on the Company's financial statements, other than increasing the level of disclosures provided in Note 14, Financial Instruments.

Recent accounting pronouncements

The IASB issued the following standards and amendments, which are not yet effective for the Company and discussed in further detail in Note 4 to the Condensed Interim Financial Statements at June 30, 2013 The IASB did not issue any standards, interpretations or amendments during the second quarter of 2013.

1. Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IFRS 7, "Financial Instruments: Disclosures" and IAS 32, "Financial Instruments: Presentation" to clarify the current offsetting model and develop common disclosure requirements to enhance the understanding of the potential effects of offsetting arrangements. Amendments to IFRS 7 are effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. Amendments to IAS 32 are effective for the Company on January 1, 2014 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the IFRS 7 amendments on January 1, 2013 and the IAS 32 amendments on January 1, 2014. The adoption of these amended standards is not expected to have a material impact on the Company's financial statements.

2. Financial Instruments: Recognition and Measurement

In November 2009, as part of the International Accounting Standards Board's (IASB) project to replace International Accounting Standard (IAS) 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the first phase of IFRS 9 *Financial Instruments*. It contained requirements for the classification and measurement of financial assets, and was updated in October 2010 to incorporate financial liabilities. The standard is applicable for annual periods starting on or after January 1, 2015.

3. Impairment of assets

In May 2013, the IASB released an amendment to IAS 36, "Impairment of Assets". This amendment requires entities to disclose the recoverable amount of an impaired Cash Generating Unit ("CGU"). The amendment is effective January 1, 2014. Early adoption is permitted.

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; and
- treatment under governmental regulatory regimes and tax laws.
- Third party drilling programs and well status reports.

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 is available on SEDAR at www.sedar.com