Overview

International Frontier Resources Corporation is engaged in the exploration for and development of petroleum and natural gas reserves in the frontier regions of the Northwest Territories, Canada and the UK sector of the North Sea. The following is management's discussion and analysis ("MD&A") of International Frontier Resources Corporation's ("International Frontier" or "IFR" or "Britcana" or the "Company") operating and financial results for the year ended December 31, 2006, as well as information concerning the Company's future outlook based on currently available information. This MD&A should be read in conjunction with the Company's December 31, 2006 audited consolidated financial statements and related notes and the Company's 51-101 report filed on Sedar. This MD&A includes subsequent events to April 17, 2007.

Operations Review

A summary for the period ending December 31, 2006 and subsequent events to April 17, 2007 is as follows;

Central Mackenzie Valley, NWT

In the Keele-Summit project area (formerly called Flintstone project area) the Company participated in the drilling of one exploration well, one appraisal well and in shooting a 185 kilometers 2D seismic program. The Company's share of 2006 expenditures in the project area was $3.8 million. A review of 2006 operations is as follows;

- The Stewart D-57 (IFR-7.5%) exploration well was drilled to evaluate both the Devonian and Cretaceous. The Devonian did not encounter commercial hydrocarbons however a new discovery was made in the shallow Cretaceous Little Bear Formation. The Little Bear sands drill-stem tested at 5 MMCF/D. The D-57 well is the first well in the Central Mackenzie Valley to produce commercial hydrocarbons from the Cretaceous. In Q1/07 the operator submitted a Significant Discovery Application to the National Energy Board covering the Stewart gas pool boundaries.

- The Summit Creek K-44 (IFR-5%) appraisal well was drilled to evaluate the reservoir encountered in the Summit Creek B-44 discovery well. The well was drilled 1.4 kilometers north of B-44, based on log interpretation and drill-stem test results it appears that K-44 encountered a separate compartment within the Summit structure. The well has been cased to 3,250 meters and it can be re-entered to test the Devonian or deepen to evaluate the Ordovician.

- In Q2/06 the consortium was awarded EL-441 (IFR-7.5%) for a work program bid of $10.5 million. The license is located on the eastern flank of EL-397 where the Summit B-44 and Stewart D-57 discoveries are located.

- The consortium acquired 185 kilometers of 2D seismic covering prospect leads in EL-423 and in EL-441. The seismic data has confirmed a drilling location on the Haywood structure located in EL-423, both the Devonian and Lower Ordovician are prospective at this location.

- At December 31, 2006 cumulative gross expenditures in the Summit – Keele project area are approximately $160 million, of which seismic expenditures represent approximately $50 million and drilling expenditures represent approximately $110 million, the Company's share of cumulative expenditures are $8.5 million.

Central Mackenzie Valley, NWT (continued)

In 2006 EL-401 and EL-414 expired. The Company's share of expenditures on the two licenses was $489,000. These costs were assessed as impaired and were written off as a result of an impairment test.

To date seven exploration wells have been drilled resulting in two discoveries, two suspended wells that require further production testing and three dry holes. All costs related to dry holes have been assessed for impairment and written off as a result of the application of an impairment test.

In 2007/08 the Company has budgeted for one firm well to test the Haywood Prospect, one contingent well to test the shallow Cloverleaf Prospect, production testing of the Sah Cho L-71 and Stewart D-57 wells and for additional seismic.

The Keele-Summit project is operated by Husky Oil Operations Ltd.

Colville Hills (25%)

In Q3/06 the Company participated in a 1040 square kilometer airborne gravity survey covering EL-429 and EL-432. Interpretation of the data has identified a number of prospect leads which will be further refined with a $12 million 2D seismic survey that will commence in Q3/07. The Colville project is operated by BG Canada.

NWT Summary

The Company holds working interests ranging from 5% to 25% in five exploration licenses and nine TDL freehold parcels encompassing 1.2 million gross acres, 146,000 net acres. The Company's acreage is located within close proximity to the Enbridge oil pipeline and the proposed Mackenzie Valley gas pipeline.

North Sea - UKCS

The Company holds an interest in seven licenses covering 14 North Sea blocks. In 2006 the Company completed a series of joint ventures that will participate in three high-impact exploration wells drilled in 2007 and, subject to rig availability, two wells in 2008. The Company conducts its North Sea operations through its wholly owned subsidiary, Britcana Energy Ltd.

A summary of the North Sea projects is as follows, all prospective resource estimates contained herein have been generated by the Company and its external consultants.

Laurel Valley- Blocks 14/23(SE/4) 14/28a & 14/29

The Laurel Valley prospect covers three North Sea blocks located in the outer Moray Firth area of the central North Sea. In Q2/06 farmout agreements were entered into with three farminees to pay 100% of drilling costs to earn; Oilexco – 45%, Gulf Shores – 9.37%, Eternal Energy – 9.18%. Oilexco was appointed operator and drilled the well using the Sedco 712. Britcana was carried for a 10.45% interest in the first well and has earned a 10.45% interest in blocks 14/23 (SE/4), 14/28a and 14/29.

The 14/28a-5 well was drilled in Q1/07 unfortunately the sands encountered were wet and the well was plugged and abandoned as a dry hole. Information from the well is being integrated into geological and geophysical models to determine if there is any remaining potential on the blocks.

Ridgewood – Block 12/17a

The Ridgewood prospect is located in the inner Moray Firth area off the east coast of Scotland. Palace Exploration UK Ltd. acquired the block at the 23rd Licensing Round. Following award Britcana acquired a 50% interest in the block by reimbursing Palace for 50% of seismic acquisition costs and committing to fund 50% of future exploration costs.

In Q3/06 a farmin agreement was entered into with Lundin Petroleum A.B. whereby Lundin will pay 40% of the cost to drill a test well to earn a 30% interest in 12/17a; Lundin has been appointed operator of the block. In addition a farmin agreements was executed with Gulf Shores Resources UK Ltd and a farmin option agreement was executed with Monarch Energy Ltd., should the option be exercised Gulf Shores and Monarch will each fund 15% of the well costs to each earn a 10% interest in 12/17a. Britcana will pay 15% of the well costs to retain a 25% interest in block 12/17a.

Lundin has contracted the Global Sante Fe Galaxy 11 rig to drill the well in the second half of 2007. The well will test a Volgian sand prospect with a prospective resource estimate (gross un-risked) of P10 – 111 MMBO, P50 - 36 MMBO and P90 - 3 MMBO. If the Volgian sands are productive the well will be deepened to test the Beatrice sands, prospective gross resources estimates for the Beatrice are P10 – 71 MMBO, P50 – 25 MMBO and P10 – 5 MMBO.

Lytham – Blocks 41/10a, 41/5, 42/1, 42/2a & 42/7

The Company will pay 5% of the cost to drill the Lytham #1 well to retain a 6.25% interest in the Quad 41/42 acreage. The operator, Lundin Petroleum A.B., has contracted the Global Sante Fe Galaxy 11 rig to drill the test well in the second half of 2007. The well test three prospective targets identified on a 3D seismic survey with a combined prospective resource of; P10 – 1.9 TCF, P50 – 690 BCF and P90 – 19 BCF (gross un-risked). If the Lytham structure is productive the St. Anne's and String of Pearls prospects will be significantly de-risked.

Bowmore Prospects – Blocks 15/23c, 15/24a, 15/28a, 15/29e

In February 2007 Britcana (10%), Nippon Oil (30% & operator), Hunt Petroleum (30%) and Stratic Energy (30%) were awarded four blocks at the UKCS 24th Licensing Round. The work program includes seismic reprocessing, two firm wells and two contingent wells.

Four prospects with the following gross un-risked prospective resource estimates have been identified.

Prospect	P10	P50	P90
15/24a -Firm Well	48 MMBO 174 BCF	30 MMBO 108 BCF	14 MMBO 59 BCF
15/23c - Firm Well	11.9 MMBO	20 MMBO	4.6 MMBO
15/24a – Contingent Well	29 MMBO 105 BCF	17 MMBO 61 BCF	10 MMBO 36 BCF
15/28a – Contingent Well	16.3 MMBO	11.9 MMBO	7.4 MMBO

Liquidity, capital resources and financing activities

Cash and cash equivalents at December 31, 2006 were $11,853,540. At December 31, 2006, the Company had working capital of $11,348,175 (2005 - $14,762,475). The decrease in working capital at December 31, 2006 as compared to 2005 is due to increased capital expenditures in 2006. The increase in working capital at December 31, 2005 was the result of funds raised from a non-brokered private placement entered into on November 3, 2005 for net proceeds of $5,307,000.

In February 2007, the Company issued 4,800,000 flow-through shares at $1.50 per share to raise gross proceeds of $7,200,000. The flow-through funds will be used to incur CEE in the Northwest Territories. In addition, the Company issued 12,400,000 units at a price of $1.25 per unit to raise gross proceeds of $15,500,000. A unit consists of one common share and one-half warrant; one full warrant entitles the holder with the right to acquire one common share at $1.60 on or before February 22, 2008.

At April 17, 2007 the Company's working capital was $33.2 million. The Company has sufficient working capital to meet all of its existing commitments and has the ability to raise capital to meet its ongoing obligations in the future.

Annual Results

The following table summarizes results for the years ended December 31, 2006, 2005 and 2004.

		2006		**2005**		**2004**
Sales volumes – BOE/day		48		50		45
Oil Revenues, net	$	746,365	$	656,080	$	561,330
Net loss	$	(1,229,645)	$	(1,837,235)	$	(3,374,950)
Net loss per share – basic	$	(0.03)	$	(0.05)	$	(0.15)
– diluted	$	(0.03)	$	(0.05)	$	(0.15)
Total assets	$	26,238,655	$	23,536,000	$	14,773,510
Working capital	$	11,348,175	$	14,762,475	$	9,936,655
Flow through share obligations	$	-	$	5,337,725	$	3,389,090

Summary

Sales volumes for 2006 were 48 BOE per day, which is comparable to 50 BOE per day in 2005. Gross revenues in 2006 were $965,370 up $99,180 or 11.5% from $866,190 in 2005. Increase in 2006 gross revenues was due to a 16.5% increase in average price per BOE received of $55.24 per barrel compared to $47.38 per barrel in 2005.

Gross overriding royalty costs were $219,000 or 23% of gross revenues in 2006 as compared with $210,000 or 24% of gross revenues in 2005. The increase in royalties in 2006 is due to increased oil prices mitigated by a decrease in production received in during the year ended December 31, 2006 as compared to the same period in 2005. In addition, royalties of $18,125 (2005 – $29,770) were paid to certain officers, directors and consultants in accordance with the Company's Royalty Incentive Plan.

During 2006, the Company incurred operating expenses of $398,785 (2005 – $409,000). Operating costs per BOE remained relatively consistent during the year averaging $22.80 per BOE throughout 2006 as compared to $22.40 per BOE in 2005.

Annual Results

Interest and other income

The Company generated interest income from short term investments of $445,100 (2005 - $214,390) for the year ended December 31, 2006. The increase in interest income in 2006 as compared to 2005 is due to interest earned on investment of funds raised through financing activities during the fourth quarter of 2005 resulting in a larger cash balance in 2006 coupled with an increase in interest rate received on investments at December 31, 2006. At December 31, 2006 Interest and other income includes $172,500 (2005 - $nil) related to North Sea prospect fees earned by the Company in the third quarter of 2006. In addition a foreign exchange gain of $3,995 (2005 - $4,745) was incurred during the year to facilitate North Sea operations.

Depletion and depreciation

Depletion, depreciation at December 31, 2006 consists of depletion and depreciation of property and equipment of $221,390 (2005 – $158,000; 2004 – $576,000) and a $1,000,620 (2005 – $45,000; 2004 – $575,960) impairment loss which represents the amount by which the carrying amount of capitalized costs related to properties in Canada exceeds the fair value of the proved reserves as estimated by McDaniel's & Associates at December 31, 2006.

The carrying value of properties in the exploration stage in the Northwest Territories of $10,251,500 (2005 – $6,046,000) and in the North Sea of $1,105,000 (2005 – $175,900) have been excluded from the depletion calculation at December 31, 2006. These properties were evaluated at December 31, 2006 and certain costs and related to licenses which expired during the year and geological and geophysical costs in the Northwest Territories were included in the carrying amount of capitalized costs for purposes of calculating depletion and impairment as discussed above.

Accretion of asset retirement obligation

The accretion of asset retirement obligations remained relatively constant at December 31, 2006 of $21,560 as compared to $21,710 for the year ended December 31, 2005.

General and administrative expenses

	2006	**2005**	**2004**
Investor relations	$ 36,170	$ 50,650	$ 351,825
Filing and transfer fees	33,580	26,445	55,150
Professional fees	143,480	151,875	73,210
Consulting fees	373,550	326,195	249,165
Less amounts capitalized	(82,800)	(105,625)	(158,730)
Rent and office costs	202,510	144,270	146,485
Part 12.6 Tax	115,835	37,810	-
Total General and administrative expenses	$ 822,325	$ 631,620	$ 717,105

General and administrative expenses increased by $190,705 or 30% to $822,325 for the year ended December 31, 2006 as compared to $631,620 for 2005. This increase is primarily a result of increases in filing and transfer fees related to financings and a general increase in office costs and consulting fees in 2006. Increase in Part 12.6 taxes at December 31, 2006 is due to increased unspent flow through share obligations at December 31, 2006 as compared to December 31, 2005.

Annual Results

Stock based compensation

Stock based compensation costs decreased from $1,562,450 in the year ended December 31, 2005 to $729,830 in the same period in 2006 due to a fewer number of options issued to officers, directors, employees and consultants during the year.

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Net Loss

The Company had a net loss of $1,229,645 or $0.03 per share in 2006, compared to $1,837,235 or $0.05 per share in 2005. The Company's net loss is affected by items which are non-operational in nature. At December 31, 2006 these non-cash items included depletion and depreciation and accretion expense of $1,243,570 (2005 – $225,145), abandonment costs incurred of $5,960 (2005 – $69,610), stock based compensation expense of $729,830 (2005 – $1,562,450), write off of investment of $Nil (2005 – $52,875), gain on sale of investment of $Nil (2005 – $4,745) and a future income tax recovery of $608,535 (2005 – $175,880) resulting in an adjusted net income (loss) from operations at December 31, 2006 of $129,260 (2005 – ($247,000)).

Financial Instruments

International Frontier does not have any commodity or financial instrument hedges. The Company carries various forms of financial instruments, all of which are recognized in International Frontier's audited consolidated financial statements at December 31, 2006. Unless otherwise denoted in the December 31, 2006 audited consolidated financial statements it is management's opinion that the Company is not exposed to significant interest, currency or credit risks arising from the these financial instruments. The fair values of financial instruments approximate their carrying value. The Company has no unrecognized gains or losses in its financial statements.

Investing Activities

Total capital expenditures for the year ended 2006 were $6,433,410 (2005 – $2,880,000) of which $5,500,000 or 85% (2005 – 76%) related to exploration activities in the Central Mackenzie Valley, NWT and $930,000 or 14% (2005 – 6%) related to exploration activities in the U.K. North Sea. Operations in these areas are expensive and of a high risk nature that could create conditions that could alter the plans of the Company and its partners. Further, should commercial quantities of petroleum and natural gas be proven to exist in the area, the timing of revenue generation is dependent on a variety of factors not within control of the Company.

Obligations

Under the terms of the flow-through agreements undertaken in 2005, the Company had flow-through share spending obligations of $Nil (2005 – $5,337,725) at December 31, 2006. The Company had no debt at December 31, 2006. The Company has sufficient working capital and future cash flow to meet its flow through share obligations. The Company is party to an agreement to lease its premises until December 31, 2011. The annual rent of premises consists of a minimum rent plus occupancy costs. Minimum rent payable for premises until the end of the lease will be $86,570 per year to the end of December 31, 2011.

Related Party Transactions

Certain officers and 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. Total amounts paid to officers and directors during the year ended December 31, 2006 in respect of consulting fees and royalties were $295,190 (2005 – $206,835). Of the total consulting fees paid to related parties during the year, $82,800 (2005 –$93,375) was capitalized to property and equipment at December 31, 2006. In addition, during the year $43,600 (2005 - $8,400) was paid to a law firm in which a Director is a partner. These costs are included in general and administrative expenses on the consolidated statements of loss and deficit at December 31, 2006.

Other Items

Outstanding shares, options and warrants

The Company's share capital structure is as follows:

As of:	**December 31, 2006**	**April 17, 2007**
Common shares outstanding	42,041,065	59,243,720
Warrants outstanding	-	7,504,000
Options outstanding	3,355,000	4,155,000
Convertible debentures	92,857	92,857
Fully diluted	45,488,922	70,995,577

Additional details on the shares, options and warrants outstanding at December 31, 2006 are available in the notes to the December 31, 2006 audited consolidated 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.

Summary of Quarterly Results

Fourth Quarter

The following summarizes the results for the three months ended December 31, 2006 compared with the same period in 2005.

Sales Volumes

Sales volumes for the fourth quarter of 2006 were 42 BOE per day, down 3 BOE per day or 3% compared with the 45 BOE per day in the fourth quarter of 2005. Decrease in sales volumes in 2006 is due to fewer wells operating at December 31, 2006.

Summary of Quarterly Results

Gross Revenues

Gross revenues were $191,185 in the fourth quarter of 2006 which is consistent with gross revenues in the fourth quarter of 2005. There was a 6.7% increase in average price per BOE received in the three months ended December 31, 2006 at $49.10 per barrel as compared to $46.04 per barrel in the third quarter of 2005 mitigated by a slight decrease in production in the three months ended December 31, 2006.

The Company also generated interest income from short term investments of $140,150 in the fourth quarter of 2006 up $94,950 from $45,200 for the three months ended December 31, 2005. The interest income received by the Company is directly related to interest earned on investment of funds raised through financing activities during 2005.

Royalty Expense

Gross overriding royalty costs were relatively consistent with $57,700 or 20% in the fourth quarter of 2006 as compared with $72,200 or 22% in the same quarter in 2005.

Operating expenses

Production expenses were $96,785 or $19.40 per BOE for the three months ended December 31, 2005 as compared with $100,180 or $25.70 per BOE in 2006. This increase of $3,395 or 3.5% was due primarily to increased costs incurred in the fourth quarter of 2006 due to decreased production, and battery maintenance performed in the period.

Depletion and Depreciation

Depletion and depreciation on oil and gas properties was $24,340 in the fourth quarter of 2005 or $7.61 per BOE compared with $16.60 per BOE or $64,625 in the fourth quarter of 2006. The increase in 2006 is mainly due to a decrease in the Company's reserve base at December 31, 2006.

General and Administrative Costs

General and administrative expenses were $423,500 for the fourth quarter of 2006 up $96,800 or 29.6% compared with $326,700 in 2005. This increase is primarily a result of increase in Part 12.6 tax accrued at December 31, 2006 with respect to flow through shares issued in 2005.

Stock based compensation

There were no stock options issued or exercised in the fourth quarter of 2006, therefore, no stock based compensation costs were booked for the three months ended December 31, 2006 which is consistent with the three months ended December 31, 2005.

Net Income (Loss)

The Company had a net loss of $345,020 or $0.01 per share per share in the fourth quarter of 2006 compared with a net loss of $228,000 or $0.01 per share for the same period in 2005. The Company's net income (loss) is affected by items which are non-operational in nature. For the three months ended December 31, 2006 these non-cash items included depletion and depreciation and accretion expense of $538,295 (2005 – $58,000), abandonment costs incurred of $5,960 (2005 – $Nil), stock based compensation expense of $Nil (2005 – $Nil), write off of investment of $Nil (2005 – $52,875) and a future income tax recovery of $445,485 (2005 – $121,000) resulting in an adjusted net loss from operations for the fourth quarter ended December 31, 2006 of $258,170 (2005 – $238,125).

Summary of Quarterly Results

The quarterly results have been prepared without audit or review by the Company's independent external auditors. The following table summarized the Company's financial and operating highlights for the past eight quarters:

Quarter ended	**Dec. 31, 2006**	**Sept. 30, 2006**	**June 30, 2006**	**March 31, 2006**
Sales volumes – Bbl/day	42	46	52	50
Revenues, net	133,490	209,990	246,080	240,305
Net income (loss)	(345,020)	(472,900)	(135,290)	(217,450)
Net loss per share – basic	(0.01)	(0.01)	(0.00)	(0.005)
– diluted	(0.01)	(0.01)	(0.00)	(0.005)
Total assets	26,238,655	25,928,020	26,402,100	23,440,490
Working capital	11,348,175	13,540,290	13,439,825	12,555,475
Restricted cash on deposit	1,538,125	1,538,125	1,596,700	2,016,225
Net cash generated (loss) from operations	(258,170)	287,250	97,650	2,530

Summary of Quarterly Results (continued)

	Dec. 31 2005	**Sept. 30, 2005**	**June. 30, 2005**	**March 31, 2005**
Sales volumes – BOE/day	45	52	56	48
Revenues, net	119,585	281,850	242,200	186,395
Net loss	(228,370)	(158,530)	(2,315)	(1,447,315)
Net loss per share – basic	(0.01)	(0.04)	(0.00)	(0.04)
– diluted	(0.01)	(0.04)	(0.00)	(0.04)
Total assets	23,536,000	17,796,340	17,802,250	17,715,050
Working capital	14,762,475	9,635,305	9,977,820	12,165,400
Restricted cash on deposit	1,441,325	1,382,750	1,382,750	351,500
Net cash generated (loss) from operations	(238,125)	65,490	27,990	(10,435)

Disclosure Controls

As of December 31, 2006, the Company's management evaluated the effectiveness of the design and operation of its disclosure controls and procedures ('Disclosure Controls'), as defined under rules adopted by the Canadian Securities Administrators. The evaluation was performed under the supervision of, and with the participation of Chief Financial Officer/ Chief Executive Officer.

Disclosure Controls are procedures designed to ensure that information required to be disclosed in documents filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis, and is accumulated and communicated to the Corporation's management to allow timely decisions regarding disclosure.

The Company's management, including the CEO/CFO, does not expect that the Company's disclosure controls will prevent or detect all errors and all fraud. Due to the inherent limitations in all control systems, an evaluation of controls can provide only reasonable, no absolute, assurance that all control issues and instances of fraud or error, if any, within the Company have been detected.

Based on the evaluation of Disclosure Controls, the CEO/CFO has concluded that, subject to the inherent limitations noted above, the Company's disclosure controls are effective in ensuring that material information relating to the Company is made known to Management on a timely basis by others is included as appropriate in this MD&A.

Internal Controls Over Financial Reporting (ICFR)

During 2006, the Company designed and implemented internal controls over financial reporting. These internal controls are designed to provide reasonable assurance regarding the reliability of the Company's financial statements for external purposes in accordance with Canadian generally accepted accounting principles. These internal controls have not been evaluated for effectiveness.

Due to inherent limitations, the Company's system of internal control over financial reporting does not guarantee that a material misstatement in the financial statements or occurrence of fraud would be prevented or detected in a timely manner. Management considers the size and the nature of the Company's operations, and exercises judgment in designing appropriate and costs effective controls for the detections and preventions of material error in the financial statements or occurrence of fraud with a potential material impact on the reliability the financial statements.

The Company has a lack of segregation of duties over the financial close and reporting functions due to limited staff. Management has concluded and the Company's board of directors has agreed that, taking into account the present stage of the Company's development and the best interest of its shareholders, the Company does not have the sufficient size and scale to warrant the hiring of additional staff to correct this weakness at this time. The Company has implemented compensating controls in the form of additional review of the financial close procedure by qualified Audit Committee members. The Company's officers and Audit Committee review the quarterly financial reports, and annual audits are conducted by the Company's independent auditors. The Company seeks third party expertise to review the more complex financial reporting items.

During the quarter ended December 31, 2006, there were no substantive changes in the nature of the Company's policies or procedures that have materially affected, or are reasonably likely to materially affect, the Company's system of internal control over financial reporting. The Company is continuing with is efforts in formalizing and documenting various elements of its system of internal control over financial reporting in preparation for the evaluation of the operating effectiveness of its internal controls system within the timeliness to be prescribed by the Canadian Securities Administrators.

Forward Looking Statements

This Management Discussion and Analysis (MD&A) contains forward-looking or outlook information which reflects management's expectations regarding the Company's growth, results of operations, performance and business prospects and opportunities. The use of words such as "anticipate", "continue", "estimate", "expect", "may", "project", "should", ""believe", ""outlook", "forecast" and similar expressions are intended to identify forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results of events to differ materially from those anticipated in these forward-looking statements. Although management believes the expectations reflected in these forward-looking statements are reasonable, there can be no assurance that actual results will be consistent with these forward-looking statements. Readers should not put undue reliance on forward-looking information. These statements are made as of the date hereof and management assumes no obligation to update or revise these statements to reflect new events or circumstances.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this management discussion and analysis.

- Volatility in market prices for oil and natural gas;
- Risks inherent in our operations;
- Geological, technical, drilling and processing problems;
- General economic conditions;
- Industry conditions, including fluctuation in the price of oil and natural gas;
- Governmental regulation;
- Fluctuation in foreign exchange and interest rates;
- Unanticipated events that can reduce production or cause production to be shut-in or delayed;
- Failure to obtain industry partner and other third party consents and approvals, when required;
- The need to obtain required approvals from regulatory authorities; and
- The other factors discussed under "Operational and Other Business Risks" in this management discussion and analysis.

Operational and other business risks

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 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 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, 2006 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.

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.

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.

Other information

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

PART 1 OIL AND NATURAL GAS RESERVES AND NET PRESENT VALUE OF FUTURE NET REVENUE

In accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities, McDaniel & Associates **("McDaniel")** prepared the McDaniel Report evaluating, as at December 31, 2006, **International Frontier Resources Corporation ("IFR")** oil reserves. The preparation date is March 19, 2007. The tables below are a summary of the oil and the net present value of future net revenue attributable to such reserves as evaluated in the McDaniel Report based on constant and forecast price and cost assumptions. The tables summarize the data contained in the McDaniel Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to IFR's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by McDaniel. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to IFR's reserves estimated by McDaniel represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of IFR's oil, reserves provided herein are estimates only and actual reserves may be greater than or less than the estimates provided herein.

The McDaniel Report is based on certain factual data supplied by IFR and McDaniel's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to IFR's petroleum properties and contacts (except for certain information residing in the public domain) were supplied by IFR to McDaniel and accepted without any further investigation. McDaniel accepted this data as presented and neither title searches nor field inspections were conducted.

PART 2 RESERVES DATA

ITEM 2.1 CONSTANT PRICES AND COSTS

Summary of Oil and Gas Reserves

	Gross Reserves(1) Light & Medium Crude Oil (Mbbls)	Net Reserves(2) Light & Medium Crude Oil (Mbbls)
Proved		
Developed Producing	84.7	68.6
Developed Non-Producing	-	-
Undeveloped	-	-
Total Proved	84.7	68.3
Probable	30	24.4
Total Proved plus Probable	114.7	93

Net Present Value of Future Net Revenue of Oil & Gas Reserves

	Before Future Income Tax Expenses & Discounted at [3]		After Future Income Tax Expenses and Discounted at	
	0% ($ 1000)	10% ($1000)	0% ($1000)	10% ($1000)
Proved				
Developed Producing	757	610	757	610
Developed Non-Producing	-	-	-	-
Undeveloped	-	-	-	-
Total Proved	757	610	757	610
Probable	438	219	438	219
Total Proved plus Probable	1195	829	1195	829

Additional Information Concerning Future Net Revenue – (Undiscounted)

	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes[1]	Income Taxes	Future Net Revenue After Incomes Taxes
	($1000)	($1000)	($1000)	($1000)	($1000)	($1000)	($1000)	($1000)
Total Proved Reserves	4483	808	2396	n/a	450	757	0	757
Total Proved Plus Probable	6070	1188	3237	n/a	450	1195	0	1195

Future Net Revenue by Production Group

	Future Net Revenue After Income Taxes& Discounted at 10% ($1000)
Proved	
Light & Medium Crude Oil[2]	610
Proved plus Probable	
Light & Medium Crude Oil [1]	829

(1) Gross Reserves include working interest reserves before royalty deductions.
(2) Net Reserves include working interest after royalty deductions plus royalty interest reserves.
(3) Before allowance for Alberta Royalty Tax Credit.

ITEM 2.2 FORECAST PRICES AND COSTS

Summary of Oil and Gas Reserves

	Gross Reserves[1] Light & Medium Crude Oil (Mbbls)	Net Reserves[2] Light & Medium Crude Oil (Mbbls)
Proved		
Developed Producing	84.7	68.6
Developed Non-Producing	-	-
Undeveloped	-	-
Total Proved	84.7	68.6
Probable	30	24.4
Total Proved plus Probable	114.7	93

Net Present Value of Future Net Revenue of Oil and Gas Reserves

	Before Future Income Tax Expenses and Discounted at [3]				
	0% ($1000)	5% ($1000)	10% ($1000)	15% ($1000)	20% ($1000)
Proved					
Developed Producing	490.8	482.2	461.2	437.7	415.1
Developed Non-Producing	-	-	-	-	-
Undeveloped	-	-	-	-	-
Total Proved	490.8	482.2	461.2	437.7	415.1
Probable	341.3	244.1	181.7	140.6	112.6
Total Proved plus Probable	832	726.3	642.9	578.3	527.7

	After Future Income Tax Expenses and Discounted at				
	0% ($1000)	5% ($1000)	10% ($1000)	15% ($1000)	20% ($1000)
Proved					
Developed Producing	490.8	482.2	461.2	437.7	415.1
Developed Non-Producing	-	-	-	-	-
Undeveloped	-	-	-	-	-
Total Proved	490.8	482.2	461.2	437.7	415.1
Probable	341.3	244.1	181.7	140.6	112.6
Total Proved plus Probable	832	726.3	642.9	578.3	527.7

Additional Information Concerning Future Net Revenue – (Undiscounted)

	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes[1]	Income Taxes	Future Net Revenue After Incomes Taxes
	($1000)	($1000)	($1000)	($1000)	($1000)	($1000)	($1000)	($1000)
Total Proved Reserves	4557	893	2655	n/a	518	491	0	491
Total Proved Plus Probable	6305	1228	3717	n/a	528	832	0	832

Future Net Revenue by Production Group

	Future Net Revenue Before Future Income Tax Expense Discounted at 10% ($1000)
Proved	
Light & Medium Crude Oil[1]	461
Proved plus Probable	
Light & Medium Crude Oil [1]	643

PART 3 PRICING ASSUMPTIONS

ITEM 3.1 CONSTANT PRICES AND COSTS

December 31, 2006 Constant Product Price Schedule

Crude Oil Prices	
West Texas Intermediate ($U.S./bbl) [1]	61.05
Edmonton Light Crude ($Cdn./bbl) [2]	67.06
Bow River Medium Crude ($Cdn./bbl) [2]	49.66
Cromer Medium Crude ($Cdn./bbl) (2)	58.96

(1) December 31, 2006 NYMEX Close.
(2) Average of Shell, Imperial, PetroCanada, Encana, Suncor pricing at December 30, 2005.

ITEM 3.2 FORECAST PRICES AND COSTS

Summary of Price Forecasts – January 1, 2007

ear	WTI Crude Oil $US/BBL (1)	Brent Crude Oil $US/BBL (2)	Edmonton Light Crude Oil $C/BBL (3)	Bow Medium Crude $C/BBL (4)	Alberta Heavy Crude $C/BBL (5)	Cromer Medium Crude $C/BBL (6)	Cond. & Natural Gasolines $/Bbl	Edmonton Propane $/Bbl	Edmonton Butanes $/Bbl	Edmonton NGL Mix $/Bbl (7)	Inflation %	US/C Excha Rat $US/$C
recast												
007	62.50	60.50	70.80	49.30	39.20	62.20	72.30	40.40	51.90	50.80	2.0	0.87
008	61.20	59.20	69.30	49.60	39.80	60.90	70.80	40.40	50.80	50.10	2.0	0.87
009	59.80	57.70	67.70	49.80	40.20	59.40	69.30	40.60	49.60	49.90	2.0	0.87
010	58.40	56.30	66.10	49.30	40.90	58.00	67.70	40.20	48.40	48.60	2.0	0.87
011	56.40	54.60	64.20	47.90	39.70	56.40	65.80	39.90	47.00	47.60	2.0	0.87
012	58.00	55.80	65.60	48.90	40.60	57.60	67.30	41.00	48.10	49.60	2.0	0.87
013	59.10	56.80	66.80	49.80	41.30	58.70	68.50	41.70	48.90	50.60	2.0	0.87
014	60.30	58.00	68.20	50.80	42.20	59.80	69.90	42.50	50.00	51.60	2.0	0.87
015	61.50	59.20	69.50	51.80	43.00	61.00	71.30	43.50	50.90	52.60	2.0	0.87
016	62.70	60.30	70.90	52.90	43.80	62.20	72.70	77.30	51.90	51.60	2.0	0.87
017	64.00	61.30	72.30	54.00	44.80	63.50	74.10	45.20	53.00	52.60	2.0	0.87
018	65.30	62.80	73.80	55.00	45.70	64.80	75.70	46.10	54.10	53.70	2.0	0.87
019	66.60	64.10	75.30	56.10	46.60	66.10	77.20	47.00	55.20	54.80	2.0	0.87
020	67.90	65.30	76.80	57.20	47.50	67.40	78.70	48.00	56.30	55.90	2.0	0.87
021	69.30	66.70	78.30	58.40	48.50	68.80	80.30	48.90	57.40	57.00	2.0	0.87
reafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.87

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API/0.5% sulphur
(2) North Sea Brent Blend 37 degrees API/1.0% sulphur
(3) Edmonton Light Sweet 40 degrees API/0.5% sulphur
(4) Bow River Medium 25 degrees API/2.1% sulphur at Hardisty, Alberta
(5) Heavy crude oil 12 degrees API at Hardisty, Alberta (after deduction of blending costs to reach pipeline quality)
(6) Midale Cromer crude oil 29 degrees API/2.0% sulphur
(7) NGL Mix based on 45 percent propane, 35 percent butane and 20 percent natural gasolines.

G070101 – Effective January 1, 2007

PART 4 RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

ITEM 4.1 RESERVES RECONCILIATION

The following table sets forth a reconciliation of IFR's total net proved probable and proved plus probable reserves as at December 31, 2006 against such reserves as at December 31, 2005 based on forecast price and cost assumptions.

	Total Proved Reserves Mbbl	Probable Reserves Mbbl	Total Proved Plus Probable Mbbl
December 31, 2005	83	23.6	106.6
Extensions	0	0	0
Improved Recovery	0	0	0
Technical Revisions	-0.6	0.8	0
Discoveries	0	0	0
Acquisitions	0	0	0
Dispositions	0	0	0
Economic Factors	0	0	0
Production	13.9	0	13.9
December 31, 2006	68.6	24.4	93

ITEM 4.2 NPV RECONCILIATION

Dec.31, 2005 vs Dec.31, 2006- Based on Constant Prices

PERIOD and FACTOR	2006 ($1000)
Estimated Future Net Revenue at Beginning of Year After Tax	**386**
Oil and Gas sales during period net of royalties and production costs	(365)
Changes due to pricing	751
Actual development costs during the period	-
Changes in future development costs	-
Changes resulting from extensions, infill drilling, and improved recovery	-
Changes resulting from discoveries	-
Changes resulting from acquisitions of reserves	-
Changes resulting from disposition of reserves	-
Accretion of discount	39
Other significant factors	-
Net changes in income taxes	-
Changes resulting from technical reserves revisions plus effects of timing	(201)
Estimated Future Net Revenue at End of Year After Tax	**610**

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

ITEM 5.1 UNDEVELOPED RESERVES

The following discussion generally describes the basis on which IFR attributes Proved and Probable Undeveloped Reserves and its plans for developing those Undeveloped Reserves.

Probable Undeveloped Reserves

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be on stream within a two year timeframe.

ITEM 5.2 SIGNIFICANT FACTORS OR UNCERTAINTIES AFFECTING RESERVES DATA

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions IFR reserves are evaluated by McDaniel & Associates, an independent engineering firm.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves (using both constant prices and costs and forecast prices and costs) and proved plus probable reserves (using forecast prices and costs only).

	Constant Prices and Costs	Forecast Prices and Costs	
	Proved Reserves (M$)	Proved Reserves (M$)	Proved Plus Probable Reserves (M$)
2005	0	0	0
2006	0	0	0
2007	0	0	0
2008	0	0	0

2009	0	0	0
Remaining Years	0	0	0
Total Undiscounted	0	0	0
Total Discounted at 10% per year	0	0	0

PART 6 OTHER OIL & GAS INFORMATION

ITEM 6.1 OIL & GAS PROPERTIES

IFR's producing oil property is located in the Alderson Area of SE Alberta, specifically Twp. 16, Rge. 11, W4M. The company owns a 100% working interest in the Lower Mannville "M2M" pool, which is comprised of five (5) producing oil wells, three (3) suspended oil wells and one (1) water disposal well. All wells are pipeline connected to a 100% W.I. central battery and separation facility.

.**Oil and Gas Wells**

The following table summarizes IFR's interest as at December 31, 2006 in wells that are producing and non-producing.

	Producing Wells Oil		**Non-Producing Wells Oil**	
	Gross	**Net**	**Gross**	**Net**
Alberta	5	5	6	6

ITEM 6.2 PROPERTIES WITH NO ATTRUBUTED RESERVES

The following table summarizes and the gross and net acres of unproved properties in which IFR has an interest and also the number of net acres for which IFR's rights to explore, develop or exploit will, absent further action, expire within one year.

	Gross Acres	**Net Acres**	**Net Acres Expiring Within One Year**
Alberta, Canada	640	160	Nil
NWT, Canada	1,233,000	146,750	Nil
North Sea, UKCS	407,000	97,740	Nil

License Details

<u>6.2.1</u>

<u>Exploration License No. 397, NWT</u>

Working interests;

At December 31, 2006 working interest in EL-397 are held as follows:

Northrock Resources Ltd. – 32.50%
Husky Oil Operations Limited – 29.4775% (operator)
EOG Resources Canada Ltd. – 26.3975%
International Frontier Resources Corporation – 5.00%
Pacific Rodera Ventures Inc – 6.625%

In 2005 the Company participated for a 5% interest in the testing of the Summit Creek B-44 discovery well. Two intervals in the Devonian were production tested; each interval produced at rates of 10 MMCF/D plus 3,000 BOPD of 55 degree condensate for a combined rate of approximately 10,000 BOEPD. In 2006 the Company participated for its 5% share, $1.5 million net to IFR, of the cost to drill the Summit Creek K-44 appraisal well. The K-44 well has been cased to total depth and further production testing is required to determine is the well is commercial.

At December 31, 2006 there are no reserves assigned to Summit Creek B-44 & K-44 or EL-397. In 2007 a significant discovery application will be submitted to the National Energy Board covering the Summit Creek discovery area.

<u>Exploration License No 423, NWT</u>

Working interests;

Northrock Resources – 32.50%
Husky Oil – 29.48% (operator)
EOG Resources – 26.4%
International Frontier – 5%
Pacific Rodera – 6.62%

EL-423 was awarded to the consortium for a work commitment of $24,800,000. In 2006 the Company participated for its share of a $10 million 2D seismic survey acquired covering portions of EL-423 and EL-441, the Company's cost for the seismic program were approximately $600,000.

A well is planned in Q1/08 to test the Haywood structure located in EL-423. Drilling of the Haywood well will extend the term for further four years. At December 31, 2006 there are no reserves assigned to EL-423.

<u>Exploration License No. 441, NWT</u>

Working Interests;

Husky Oil (operator) – 25.9175%
Northrock Resources – 27.6850%
EOG Resources – 26.3975%
International Frontier – 7.50%
Pacific Rodera – 12.50%

In June 2006 the consortium was awarded EL-441 for a work commitment of $10,500,000. In 2006 an aeromag gravity survey was acquired, the Company's net cost to acquire the survey was approximately $150,000. At December 31, 2006 there are no reserves assigned to EL-441.

<u>TDL Freehold Lands, NWT</u>

At December 31, 2006 working interests in the Tulita District Land Corporation ("TDL") Freehold lands are held as follows;

M-32, M-33, M-34, M-35 and M-39

Northrock Resources – 48.1482%
International Frontier – 16.1111% (operator)
Pacific Rodera – 9.8148%
EOG Resources – 25.9259%

In 2006 the consortium paid TDL annual lease rentals of $20 per hectare. At December 31, 2006 there are no reserves assigned to the freehold parcels.

M-29

Northrock Resources – 32.50%
Anadarko Canada – 32.50%
International Frontier – 10.875%
Pacific Rodera – 6.625%
EOG Resources – 17.50%

In 2006 the consortium paid TDL annual lease rentals of $20 per hectare. At December 31, 2006 there are no reserves assigned to M-29.

M-38

Northrock Resources – 27.685%
International Frontier – 7.50%
Pacific Rodera – 12.50%
EOG Resources – 26.3975%
Husky Oil – 25.9175%

In 2006 the consortium paid TDL annual lease rentals of $20 per hectare. In Q1/06 the consortium drilled the Stewart D-57 discovery well on TDL parcel M-38. The Company's share of the D57 drilling costs was approximately $2.1 million. The D-57 well flowed gas on DST at rates of approximately 5 MMCF/D. In Q4/06 the operator submitted a Significant Discovery Application to the National Energy Board; the application covers pool boundaries for the Stewart discovery area. At December 31, 2006 there are no reserves assigned to M-36.

M-37

International Frontier – 5.00%
Pacific Rodera – 6.625%
Northrock Resources – 32.50%
EOG Resources – 23.375%
Husky Oil – 32.50% (operator)

In 2006 the consortium drilled the Sah Cho L-71 well on TDL parcel M-37 at a gross approximate cost of $19.5 million, $950,000 net to IFR. In 2006 the consortium paid TDL annual lease rentals of $20 per hectare and a delay shut-in royalty payment of $150,000, $7,500 net to IFR. At December 31, 2006 there are no reserves assigned to M-37.

M-36
Northrock Resources – 27.6850%
International Frontier – 5.00%
Pacific Rodera – 6.625%%
EOG Resources – 23.375%
Husky Oil – 25.9175% (operator)

The consortium paid annual lease rentals of $20 per hectare. At December 31, 2006 there are no reserves assigned to parcels M-38.

Colville Hills, NWT

The Company (25%) and BG Canada Exploration and Production Inc (75%) were awarded two Exploration Licenses in the Colville Hills area, NWT. The licenses awarded cover EL-429 (210,500 acres) for a work commitment of $12,500,000 and EL-432 (162,680 acres) was awarded for a work commitment of $4,000,000. The licenses are operated by BG Canada Exploration and Production, Inc a subsidiary of BG Group plc.

The Company has lodged a Letter of Credit in the amount of $1,031,250. The Letter of Credit is refundable on the basis of $1 for every $4 incurred as qualified expenditures.

In 2006 the Company participated in an airborne gravity survey covering EL-429 and EL-432, the Company net costs for the project was approximately $190,550. At December 31, 2006 there are no reserves assigned to EL-429 and EL-432.

Hay River, NWT

The Company entered into a Memorandum of Understanding ("MOU") with the Katlodeeche First Nations ("KFN"). The MOU provides the Company with access to Hay River Reserve Lands and Katlodeeche Traditional Lands covering an area of approximately 1.9 million acres. IFR (100%) has the right to acquire sub-surface rights on Reserve Lands (35,000 acres) but not on KFN Traditional Lands as these lands are subject to the Deh Cho moratorium on oil and gas exploration in the Deh Cho region.

Under the terms of the MOU IFR will incur 100% of all exploration and development costs on the KFN acreage to earn 95% of all net revenues; KFN will receive a 5% carried interest. Upon the Company recovering 135% of all capital expenditures all future net revenues will be shared IFR-50% and KFN-50%.

In 2005 the Company issued KFN 75,000 common shares at a deemed price of $2 per share. The Company did not incur any expenditure's in 2006. At December 31, 2006 there are no reserves assigned to the KFN acreage.

North Sea UKCS

The Company operates in the UK through its wholly owned subsidiary, Britcana Energy Ltd.

Laurel Valley Prospect
Quad 14 – blocks 14/23, 14/28a, 14/29b (62,985 acres)
In 2006 the Company entered into a series of farmin agreements. Working interest are held as follows;

Oilexco North Sea Inc. – paid 75% to earn 45.00% (operator)
Gulf Shores Resources UK Ltd. – paid 12.50% to earn 9.37%
EERG North Sea Ltd. – paid 12.50% to earn 9.18%
Lundin Petroleum AB – 10.00%
Palace Exploration UK & Challenger Minerals – 16%
Britcana Energy Ltd. – 10.45%

Pursuant to the terms of the farmin agreements Britcana Energy Ltd. was carried for a 10.45% interest in the cost to drill the first well on the Laurel Valley Prospect. The well was drilled in Q1/07 and the terms of the farmin agreement have been fulfilled. The well was plugged and abandoned as a dry hole in April 2007. In 2006 Britcana incurred approximately US$238,000 for its share of the cost to acquire a 3D seismic survey.

At December 31, 2006 there are no reserves assigned to the Quad 14 acreage.

Lytham St. Anne's Prospect
Quads 41/42 – blocks 41/5, 41/10a, 41/7, 42/1, 42/29 (225,338 acres)
In 2006 a series of farmin agreements were entered into. Under the terms of the agreements a test well is to be drilled on or before December 31, 2007. Upon drilling a test well working interests will be held as follows;

Lundin Petroleum AB – 30.00% (operator)
Palace Exploration UK Ltd. – 33.50%
Challenger Minerals – 10%
Eternal Energy Corp – 10%
Gulf Shores Resources UK Ltd – 10%
Britcana Energy Ltd. – 6.25%

Britcana is required to pay 5.00% of the cost to drill, test, complete or abandon the Lytham # 1 well to earn a 6.25% working interest in the Quad 41/42 acreage.

At December 31, 2006 there are no reserves assigned to the Quad 41/42 acreage.

Ridgewood Prospect - Block 12/17 (17,900 acres)
In 2006 Palace and Britcana entered into a series of farmin agreements and farm-in option agreements. If all of the farmin and farmin option agreements are exercised, and upon drilling a test well working interests will be held as follows;

Lundin Petroleum AB – 30%
Palace Exploration UK Ltd. – 25%
Britcana Energy Ltd. – 25%

Gulf Shores Resources UK Ltd. – 10%
Monarch Energy Ltd. – 10%

In 2006 Britcana reimbursed Palace US$500,000 for seismic costs to earn a 50% interest in block 12/17. In 2007 Britcana is required to pay 15% of the cost to drill, test, complete or abandon a test well on block 12/17 to retain a 25% interest.

At December 31, 2006 there are no reserves assigned to block 12/17.

Gleneagles Prospect - Block 12/23 (26,676 acres)
At December 31, 2006 working interests are as follows;
Palace Exploration Ltd – 28.33%
Hunt Oil UK limited – 33.33%
Endeavour Oil & Gas Ltd. – 33.33% (operator)
Britcana Energy Ltd. – 5%

Block 12/23 was awarded as a promote license at the 23rd Licensing round. There were no expenditures incurred on block 12/23 in 2006. As of December 31, 2006 there are no reserves assigned to block 12/23.

ITEM 6.3 FORWARD CONTRACTS

The company does not have any product price hedges on forward contracts at December 31, 2006.

ITEM 6.4 ABANDONMENT AND RECLAMATION COSTS

IFR estimates well abandonment costs typically area by area. Such costs are included in the McDaniel Report as deductions in arriving at future net revenue. The expected total abandonment and reclamation costs included in the McDaniel Report for eight (8) wells under the proved reserves category is ($544,000) undiscounted ($302,000) discounted at 10%. This estimate includes expected reclamation costs for surface leases. Expected future abandonment costs related to facilities are expected to match the salvage value recovery. The Company does not envision abandoning any of the eight wells in the next three year period.

ITEM 6.5 TAX HORIZON

IFR has approximately $3,274,000 of tax pools available for future deduction. The Company does not expect to pay income taxes in 2007.

ITEM 6.6 COSTS INCURRED

The following table summarizes IFR's property acquisition costs, exploration costs and development costs for the year ended December 31, 2006.

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration & Drilling Costs	Development & Facilities Costs
Total ($)	-	-	6,433,410	-

ITEM 6.7 EXPLORATION & DEVELOPMENT ACTIVITIES

In 2006 the Company participated in the drilling of two exploration wells in the Central Mackenzie Valley, NWT. The Stewart D-57 well was drill stem tested at rates of 5 MMCF/D. In 2007 the operator submitted a Significant Discovery Application to the National Energy Board the application covers pool boundaries for the Stewart discovery.

In 2006 the Company participated in the drilling of the Stewart Creek K-44 appraisal well, the K-44 well was drilled 1.4 kilometers north of the B-44 well. Interpretation of the K-44 well information indicates the well may have encountered a separate compartment within the Summit structure. Additional production testing of the Summit Creek K-44 well is required.

In 2006 the Company participated in geological and geophysical programs in the Central Mackenzie Valley and Colville Hills areas of the Northwest Territories and in the UK sector of the North Sea.

DRILLING ACTIVITY

The following table summarizes IFR's drilling results for the year ended December 31, 2006.

	Exploratory Wells	
	Gross	**Net**
Natural Gas	2	0.08
Dry	0	0
Total	2	0.08

ITEM 6.8 PRODUCTION ESTIMATES

The following table discloses, by field for each product type, the total volume of production estimated by McDaniel for 2007 in the estimates of future net revenue from proved reserves disclosed above under the heading "Oil and Natural Gas Reserves and Net Present Value of Future Net Revenue".

	Light and Medium Crude Oil (Bbbls/d)	BOE (BOE/d)
Alderson	42	42
Total	42	42

ITEM 6.9 PRODUCTION HISTORY

The following table discloses, on a quarterly basis for the year ended December 31, 2006, IFR's share of average daily production volume, prior to royalties, and the prices received, royalties paid, production costs incurred and netbacks on a per unit of volume basis for each product type.

__Average Daily Production Volume__

	Three Months Ended				
	Mar. 31, 2006	**June 30, 2006**	**Sept. 30, 2006**	**Dec. 31, 2006**	**Total**
Light & Medium Crude Oil (Bbl/d)	51BOP/D	52BOP/D	46BOP/D	42BOP/D	47.5BOP/D
Total (BOE/d)	51 bop/d	52 bop/d	46 bop/d	42 bop/d	47.5bop/d

Prices Received, Royalties Paid, Production Costs and Netbacks

	Three Months Ended				
($/bbl)	**Mar. 31, 2006**	**June 30, 2006**	**Sept. 30, 2006**	**Dec. 31, 2006**	**Total**
Prices Received	43.66	64.24	62.50	48.35	54.69
Royalties Paid	9.65	12.49	13.81	11.01	11.74
Production Costs	20.77	18.32	27.21	26.54	23.21
Netback(1)	13.26	33.43	21.46	11.04	19.79

Note: (1) Netback is calculated by deducting royalties paid and production costs from prices received.

Production costs in 2006 include non re-occurring Sidox pilot project costs.

__Production Volume by Field__

The following table indicates the average daily production from IFR's producing properties for the year ended December 31, 2006.

Field	**BOE (BOE/d)**	**%**
Alderson	47.5	100
Total	47.5	100

APPENDIX "A"

McDaniel & ASSOCIATES CONSULTANTS LTD. Oil & Gas Reservoir Evaluations

March 13, 2007
International Frontier Resources Corporation
100, 601 – 10 Avenue SW
Calgary, Alberta

Attention: The Board of Directors of International Frontier Resources Corporation

Re: **Form 51-101F2**
Report on Reserves Data by an Independent Qualified Reserves Evaluator of International Frontier Resources Corporation (the "Company")

Dear Sir:

To the Board of Directors of International Frontier Resources Corporation (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2006. The reserves data consists of the following:
   (a) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs and the related estimated future net revenue; and
   (b) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using constant prices and costs and the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express and opinion on the reserves data based on our evaluation. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to provide plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended December 31, 2006, and identifies the respective portions thereof that we have evaluated, audited and reviewed and reported on to the Company's management:

Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
		Audited	Evaluated	Reviewed	Total
March 13,2007	Canada	-	643	-	643

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.
6. We have no responsibility to update our report for events and circumstances occurring after the preparation date.
7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

"signed by P.A. Welch"

P.A. Welch, P.Eng.
President and Managing Director

Calgary, Alberta

APPENDIX "B"
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Management of **International Frontier Resources Corporation,** (the "**Corporation**") is responsible for the preparation and disclosure, or arranging for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) Proved and Proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs: and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and

(ii) the related estimated future net revenue.

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

The Reserves Committee of the Board of Directors of the Corporation has:

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

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

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

The Reserves Committee of the Board of Directors has reviewed the Corporation's procedure for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluator on reserves data; and

(c) the content and filing of this report.

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

(signed) *"Pat Boswell"*
Pat Boswell
President & Chief Executive Officer

(signed) *"Mark Powell"*
Mark Powell
Director, Chairman of Reserve Committee

(signed) *"Laurie Smith*
Luarie Smith
Director

(signed) *"Bill McNaughton"*
Bill McNaughton
Director

April 17, 2007