FALCON OIL & GAS LTD.

FORM 51-102F1
MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE YEAR ENDED DECEMBER 31, 2009

The following management's discussion and analysis (the "**MD&A**") was prepared as at April 29, 2010 and is management's assessment of Falcon Oil & Gas Ltd's ("**Falcon**") financial and operating results and provides a summary of the financial information of the Company for the year ended December 31, 2009. This MD&A should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2009 and 2008.

The information provided herein in respect of Falcon includes information in respect of its wholly-owned subsidiaries Mako Energy Corporation ("**Mako**"), a Delaware company, Falcon Oil & Gas USA, Inc. ("**Falcon USA**"), a Colorado company, TXM Oil and Gas Exploration Kft., a Hungarian limited liability company doing business as TXM Energy, LLC ("**TXM**"), TXM Marketing Trading & Service, LLC ("**TXM Marketing**"), a Hungarian limited liability company, FOG-TXM Kft., a Hungarian limited liability company, JVX Energy S.R.L. ("**JVX**"), a Romanian limited liability company, and Falcon Oil & Gas Australia Pty. Ltd ("**Falcon Australia**") (collectively, the "**Company**").

Additional information related to the Company, including the Company's Annual Information Form ("**AIF**") for the year ended December 31, 2009 dated April 29, 2010, can be found on the System for Electronic Document Analysis and Retrieval (**"SEDAR"**) at www.sedar.com and Falcon's website at www.falconoilandgas.com.

Forward-looking Statements

Forward-looking statements include, but are not limited to, statements with respect to: the focus of capital expenditures; the sale, farming in, farming out or development of certain exploration properties using third party resources; the impact of changes in petroleum and natural gas prices on cash flow; drilling plans; processing capacity; operating and other costs; the existence, operation and strategy of the commodity price risk management program; the approximate and maximum amount of forward sales; the Company's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom; the Company's goal to sustain or grow production and reserves through prudent management and acquisitions; the emergence of accretive growth opportunities; the Company's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets; development costs and the source of funding thereof; the quantity of petroleum and natural gas resources or reserves; treatment under governmental regulatory regimes and tax laws; liquidity and financial capital; the impact of potential acquisitions and the timing for achieving such impact; expectations regarding the ability to raise capital and continually add to reserves through acquisition and development; the performance characteristics of the Company's petroleum and natural gas properties; and realization of the anticipated benefits of acquisitions and dispositions.

Some of the risks and other factors, which could cause results to differ materially from those expressed in the forward-looking statements include, but are not limited to: general economic conditions in Canada, the United States of America (the "**United States**"), the Republic of Hungary ("**Hungary**"), the Commonwealth of Australia ("**Australia**"), and globally; supply and demand for petroleum and natural gas; industry conditions, including fluctuations in the price of petroleum and natural gas; governmental regulation of the petroleum and natural gas industry, including income tax, environmental and regulatory matters; fluctuation in foreign exchange or interest rates; risks and liabilities inherent in petroleum and natural gas operations, including exploration, development, exploitation, marketing and transportation risks; geological, technical, drilling and processing problems; unanticipated operating events which can reduce production or cause production to be shut-in or delayed; the ability of our industry partners to pay their proportionate share of joint interest billings; failure to obtain industry partner and other third party consents and approvals, when required; stock market volatility and market valuations; competition for, among other things, capital, acquisition of reserves, processing and transportation capacity, undeveloped land and skilled personnel; the need to obtain required approvals from regulatory authorities; and the other factors considered under "Risk Factors" in the AIF.

In addition, other factors not currently viewed as material could cause actual results to differ materially from those described in the forward-looking statements.

Dollar Amounts

All dollar amounts below are in United States dollars, except as otherwise indicated. The financial information provided herein has been prepared in accordance with Canadian generally accepted accounting principles.

OVERVIEW OF BUSINESS AND OVERALL PERFORMANCE

About Falcon

The Company is an international energy company engaged in the business of acquiring, exploring and developing petroleum and natural gas properties, with offices in Vancouver, British Columbia, Denver, Colorado, Budapest, Hungary and Sydney, Australia. The Company's registered office is located at 810-675 West Hastings Street, Vancouver, British Columbia, Canada V6B 1N2 and the Company's head office is located at 1875 Lawrence Street, Suite 1400, Denver, Colorado, U.S.A. 80202.

The Company's primary focus is the acquisition, exploration and development of conventional and unconventional petroleum and natural gas projects in Central Europe, specifically Hungary, and in Australia with the Beetaloo Basin project.

Hungary

The Company holds a long-term Mining Plot (the "**Production License**") granted by the Hungarian Mining Authority. The lands within the Production License were formerly part of the Company's two petroleum and natural gas exploration licenses – the Tisza License and the Makó License (collectively, the "**Exploration Licenses**"). The Production License, covering approximately 245,775 acres, gives the Company the exclusive right to explore for petroleum and natural gas on properties located in south central Hungary near the town of Szolnok. The Production License further gives the Company the exclusive right to commercially develop petroleum and natural gas within the area covered by that license.

The Exploration Licenses expired on December 31, 2009, and are not eligible for extension. However, under Hungarian laws applicable to oil and gas exploration licenses, the licensee has the first priority in obtaining a mining plot covering all or part of the area, but is not guaranteed that it will receive a mining plot. The process requires the filing of a "Closing Report" within six months from the expiration of the license, and the filing of an application for the mining plot within the second six-month period. The Company intends to file a Closing Report within the required period.

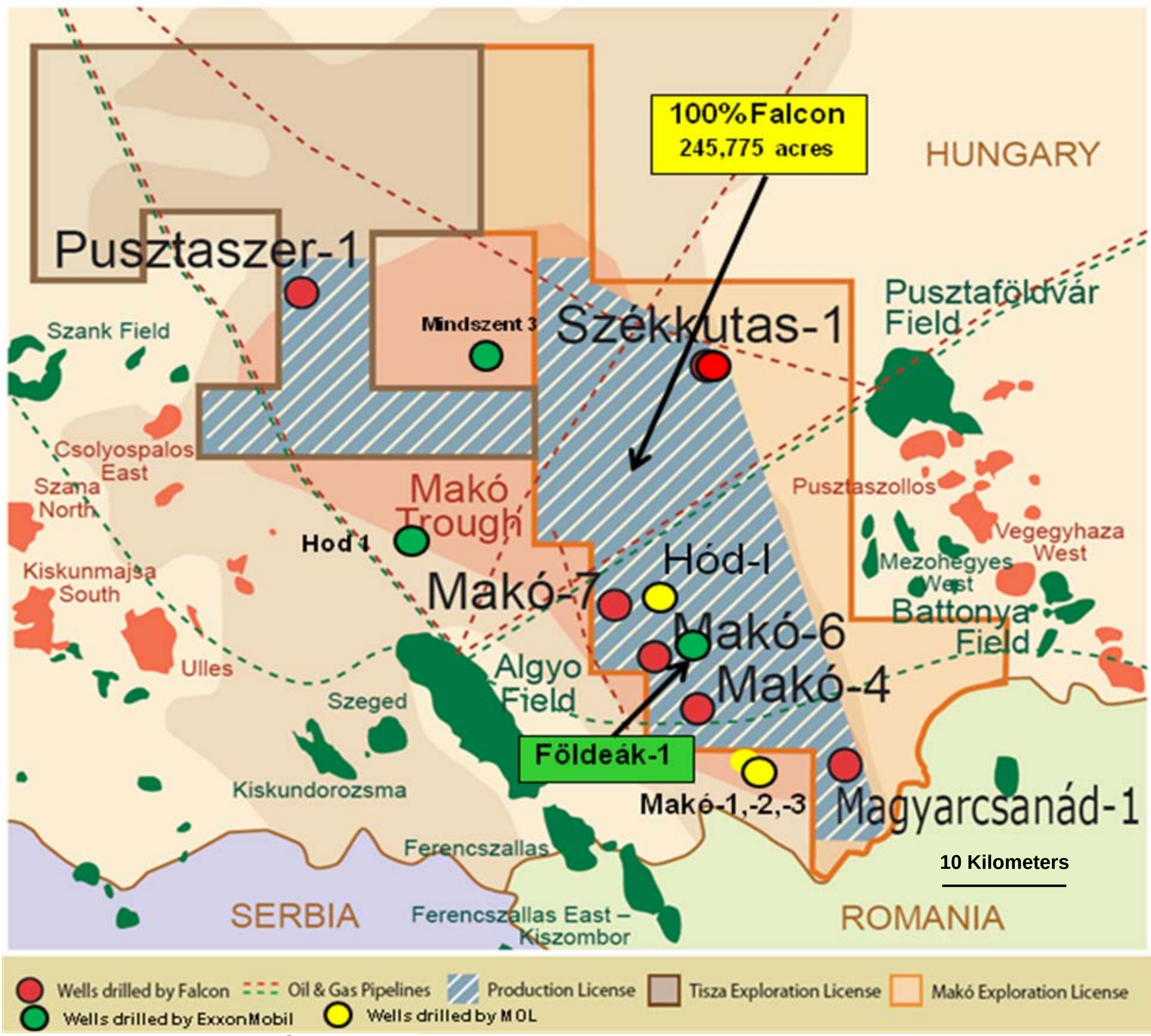
On April 10, 2008, Falcon and TXM entered into the Production and Development Agreement (the "**PDA**"), as amended, with ExxonMobil Corporation affiliate Esso Exploration International Limited ("**ExxonMobil**") under which Falcon and ExxonMobil became joint owners in a specified portion (the "**Contract Area**") of the Production License. Pursuant to a pre-existing agreement between ExxonMobil and MOL Hungarian Oil and Gas Plc. ("**MOL**") and ExxonMobil's rights under the PDA, ExxonMobil sold one-half of its interest in the Contract Area to MOL, effective April 10, 2008. ExxonMobil, MOL and TXM entered into a joint operating agreement (the "**JOA**"), dated April 10, 2008, which governed all operations of the Contract Area not expressly addressed in the PDA. ExxonMobil was designated as the operator of the Contract Area under the JOA.

The Contract Area consisted of approximately 184,300 acres, or 75% of the Company's 246,000-acre Production License. The Contract Area was owned jointly, with the Company owning a 33% undivided working interest and ExxonMobil and MOL each owning a 33.5% undivided working interest. However, the Company's Hungarian subsidiary, TXM, remained as the registered owner of the Production License under the records of the Hungarian Mining Authority.

The PDA provided for ExxonMobil and MOL to pay an initial consideration of $25 million to the Company and to spend an aggregate of $50 million to conduct an initial work program to test one or more of the Company's existing well bores or drill one or more new wells for such tests (the "**Initial Work Program**").

On October 30, 2009, Production Ventures East Hungary Kft., an affiliate of ExxonMobil ("**Production Ventures**"), completed certain operations on the Földeák-1 well, at which time the well was temporarily suspended. The conclusion of these operations was also the completion of the Initial Work Program, and the expenditure of Production Ventures' and MOL's $50 million financial obligation under the PDA. Production Ventures and MOL had 120 days from completion of the Initial Work Program to evaluate the results and, on February 19, 2010, provided notice that they would not proceed to the next phase of the PDA, the Appraisal Work Program, and would exit the PDA.

In accordance with the PDA, ExxonMobil's and MOL's respective participating interests in the Contract Area, the Földeák-1 well, and all other interests automatically reverted to TXM, and TXM became operator of the entire Production License.



Resource Estimates

In May 2008, Falcon received a resource estimate from RPS Scotia, Inc. ("**RPS Scotia**") for the Makó Trough, Hungary effective March 31, 2008 (the "**RPS Scotia Report**"). The RPS Scotia Report is an update to the Company's previous resource estimate of the Makó Trough dated and effective in July 2006 (the "**Scotia Report**").

The RPS Scotia Report is compliant with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("**NI 51-101**").

The RPS Scotia Report provides a probabilistic distribution of the potentially recoverable portion of "Contingent Resources" as defined by the Canadian Oil and Gas Exploration Handbook ("**COGEH**") and does not represent an estimate of reserves.

Based on all available data, RPS Scotia has assigned the following probabilistic estimation of potentially recoverable contingent resources to the Company's interests in the Szolnok formation, the Lower Endrod, the Basal Conglomerate and the Synrift Sequence. The RPS Scotia Report measures the Makó Trough in trillions of cubic feet of natural gas ("**Tcf**") and millions of barrels of oil ("**mmbo**"):

	Probability Greater Than		
	P90 (90%)	P50 (50%)	P10 (10%)
Probabilistic estimation of potentially recoverable contingent resources (1) (2)	**25.8 Tcf** **42.6 mmbo**	**43.9 Tcf** **97.8 mmbo**	**68.0 Tcf** **202.7 mmbo**

Notes:

(1) The resource estimate has been conducted using the definitions specified by the COGEH. The Makó Trough resource falls under the "Discovered Resources" classification. The values refer to the probabilistically estimated recoverable fraction of "Contingent Resources" within that classification. Contingent resources are those quantities of oil and gas, estimated on a given date, to be potentially recoverable from known accumulations, but are not currently economic. The economic nature of this resource has not yet been assessed due to the early stage of data gathering for the Makó Trough resource. The recoverable portion of this "Contingent Resource" is contingent upon the demonstration of productive capability of the various zones of interest through well testing and longer term production testing which has not occurred as of the effective date of the report.

(2) Estimates are as of March 31, 2008, the effective date of the RPS Scotia Report.

A copy of the RPS Scotia Report is available on SEDAR and Falcon's website.

Operational Highlights for 2009

In May 2009, ExxonMobil reached total depth of 14,500 feet (4,421 meters) on the drilling of the Földeák-1 well. This well is part of the Initial Work Program under the PDA. The primary focus of the Initial Work Program and the Földeák-1 well was to test the Szolnok Formation.

On October 30, 2009, ExxonMobil completed the third and final fracture of the Szolnok Formation in the Földeák-1 well at a depth of approximately 12,631 feet (3,850 meters). The prior two fractures were at depths of 13,780 feet (4,200 meters) and 14,298 feet (4,358 meters). The third fracture completed ExxonMobil's $50 million financial obligation under the PDA, and completed the Initial Work Program. The Földeák-1 well has been temporarily suspended to allow future access as required.

ExxonMobil and MOL had 120 days from completion of the Initial Work Program to evaluate the results and, on February 19, 2010, provided notice that they would not proceed to the next phase of the PDA, the Appraisal Work Program, and would exit the PDA.

In accordance with the PDA, ExxonMobil's and MOL's respective participating interests in the Contract Area, the Földeák-1 well, and all other interests automatically reverted to TXM, and TXM became operator of the entire Production License.

In October 2009, the Hungarian Mining Authority granted the Company's application to expand the depths under the Production License. When originally issued in May 2007, the upper depth of the

Production License was defined as 9,186 feet (2,800 meters) from the surface, and extended to the basement of the Basin Centered Gas Accumulation (the "**BCGA**"). As a result of additional technical analysis, including extensive review of 3D seismic and the data obtained from the wells previously drilled within the Production License, the amended Production License now incorporates depths beginning at 7,546 feet (2,300 meters) throughout the entire Production License. This revision makes the Production License depth consistent with other mining plots in the immediate area.

Future Operations

Future operations in the Makó Trough are subject to further technical evaluation by the Company. Operations within the Production License are also subject to ongoing efforts to enter into joint venture arrangements to evaluate the Algyo, Szolnok, Endrod and Basal Conglomerate formations.

Beetaloo Basin, Northern Territory, Australia

On September 30, 2008, Falcon and Falcon Australia consummated the acquisition of an undivided 50% working interest in an aggregate 7,000,000 acres in four exploration permits (the "**Permits**") in the Beetaloo Basin, Australia (the "**Beetaloo Basin Project**") pursuant to the terms of a Purchase and Sale Agreement, as amended on October 31, 2008, (the "**Beetaloo PSA**") with PetroHunter Energy Corporation, PetroHunter Operating Company and Sweetpea Petroleum Pty Ltd. ("**Sweetpea**") (collectively, "**PetroHunter**"), each of which is a non-arm's length party for the purposes of the TSX Venture Exchange (the "**TSXV**").

On June 11, 2009, pursuant to a second Purchase and Sale Agreement (the "**Second PSA**") with PetroHunter, the Company completed the acquisition of an additional undivided 25% working interest in the Beetaloo Basin Project. Under the terms of the Second PSA, the principal consideration being paid by the Company for this transaction was the exchange of a $5,000,000 note receivable from PetroHunter. In addition, the Company agreed to pay certain vendors who had provided goods or services for the Beetaloo Basin Project, prior to the Company acquiring its 50% interest in September 2008, in exchange for inventory and operator bonds of approximately the same value, and has relinquished its right to the unexpended testing and completion funds of the Buckskin Mesa Project (as defined below). Upon closing, the Company became operator of the Beetaloo Basin Project, and PetroHunter and the Company entered into an escrow agreement governing the release of all remaining common shares of Falcon ("**Common Shares**") previously issued to PetroHunter.

On December 7, 2009, Falcon and Falcon Australia entered into a Binding Heads of Agreement (the "**Agreement**") with PetroHunter and Sweetpea wherein Falcon Australia will issue to Sweetpea common shares of Falcon Australia in consideration for the transfer of Sweetpea's undivided 25% working interest in the Permits. The Company will enter into a Master Services Agreement (the "**MSA**") related to the operations of the Permits. Under the terms of the Agreement, Falcon will be issued 150 million shares of Falcon Australia for conversion of a portion ($30,000,000) of Falcon Australia's debt payable to Falcon, which approximates Falcon's initial acquisition cost previously paid to Sweetpea for the 75% working interest in the Permits held by Falcon Australia as of the date of the Agreement, and Sweetpea will be issued 50 million shares of Falcon Australia for its remaining 25% working interest in the Permits. On April 23, 2010, Falcon Australia received notice (the "**Notice**") from the Department of Resources, Northern Territory Government, that the registration of the transfer of the remaining 25% interest in the Permits was completed, satisfying all conditions precedent to closing. Pursuant to the Notice, Falcon Australia now owns 100% of the Permits.

The Permits are subject to a combined governmental royalty of between 10-12% and an overriding royalty to two arm's length third parties in an amount not to exceed 12.1%.

Operational Highlights for 2009

PetroHunter had previously drilled one well in 2007, the Shenandoah-1 well, which was cased and suspended at 5,100 feet (1,555 meters). In July 2009, the Company re-entered the Shenandoah-1 well, which reached a depth of 8,904 feet (2,714 meters) on October 11, 2009.

In the Shenandoah-1 well, significant gas shows were encountered in the Lower Kyalla Shale and the Middle Velkerri Shale. Shows were also encountered in the Moroak Sandstone which lies between the two thermally mature gas shales. A 328-foot (100 meter) interval in the Lower Kyalla Shale encountered significant gas shows, with gas concentrations to 11%, and total gas reaching up to 1,000 units in the most favorable Kyalla gas interval at a depth of 5,167 feet to 5,495 feet (1,575 meters to 1,675 meters). A 433 foot (132 meter) interval in the Middle Velkerri Shale from 7,890 feet to 8,386 feet (2,405 meters to 2,556 meters) had similar gas shows. Several intervals in the Moroak Sandstone also had gas shows in a composite 295 foot (90 meter) interval in what appears to be a conventional structural trap. Cores from both the Lower Kyalla and Middle Velkerri shales were taken for desorption analyses. Preliminary results indicate the shales are good gas reservoirs comparable to or exceeding recent gas shale desorption results in U.S. basins for Paleozoic source rocks.

The Shenandoah-1 well indicates a significant shallow oil zone within the Upper Kyalla Shale at a depth from 3,110 feet to 3,346 feet (948 meters to 1,020 meters). These oil and gas shows in the Shenandoah-1 well support the recent Ryder Scott evaluations (see below) of the conventional and unconventional oil and gas potential in the Precambrian sediments of the Beetaloo Basin, Northern Territory, Australia (see below).

Resource Estimates

In August 2009, the Company received a Resource Analysis Report from Ryder Scott Company - Canada (the "**Ryder Scott Report**") on the Beetaloo Basin Project, dated August 5, 2009 and effective as of July 1, 2009.

The Ryder Scott Report on the hydrocarbon resource potential of the Beetaloo Basin describes a possible distribution of the un-risked prospective (recoverable) portion of un-risked "Undiscovered in-place Resources," as defined by the COGEH, and does not represent an estimate of reserves or contingent resources. The Ryder Scott Report has been prepared in accordance with the Canadian standards set out in the COGEH and is compliant with NI 51-101. Ryder Scott's resource evaluation of the Beetaloo Basin is as follows:

Table 9: Total Undiscovered and Prospective (Recoverable) Oil Resources in the Beetaloo Basin, Australia (1) (2)						
	Un-risked Undiscovered Oil-In-Place (Bstb)			**Un-risked Prospective (Recoverable) Oil Resources (Bstb)**		
	Low	**Best**	**High**	**Low**	**Best**	**High**
Hayfield	0.049	0.088	0.148	0.005	0.010	0.018
Jamison	8.220	11.920	16.402	0.800	1.337	2.153
Conventional subtotal	8.269	12.008	16.550	0.805	1.347	2.171
Upper Kyalla shale oil	127.4	180.9	256.0	11.3	17.8	27.4
Shale oil subtotal	127.4	180.9	256.0	11.3	17.8	27.4
Total oil resource within the Beetaloo Basin	135.67	192.91	272.55	12.11	19.15	29.57

Table 10: Total Undiscovered and Prospective (Recoverable) Gas Resources in the Beetaloo Basin, Australia(1) (2)						
	Un-risked Undiscovered Gas-In-Place (Tscf)			**Un-risked Prospective (Recoverable) Gas Resources (Tscf)**		
	Low	**Best**	**High**	**Low**	**Best**	**High**
Hayfield (associated solution)	0.013	0.025	0.046	0.002	0.004	0.009
Jamison (associated solution)	2.041	3.330	5.349	0.313	0.585	1.066
Moroak	0.800	1.437	2.346	0.607	1.048	1.731
Conventional subtotal	2.85	4.79	7.74	0.92	1.64	2.81
Moroak BCGA	21.00	29.61	40.85	3.18	4.85	7.23
Bessie Creek BCGA	159.4	210.0	275.0	23.8	34.4	49.4
BCGA subtotal	180.39	239.58	315.81	27.02	39.28	56.64
Lower Kyalla shale gas	12.70	15.80	19.20	1.90	2.60	3.50
Middle Velkerri shale gas	94.6	125.1	160.4	14.2	20.4	29.0
Shale gas subtotal	107.3	140.9	179.6	16.1	23.0	32.5
Total gas resource within the Beetaloo Basin	290.54	385.27	503.16	44.05	63.91	91.94

(1) Tables 9 and 10 are from the Ryder Scott Report. For a definition of "Low" "Best" and "High," see Section 5 of the Ryder Scott Report titled "Definitions of Resources and Reserves," item 5.3.5 titled "Uncertainty Category." The total oil and gas resource is an arithmetic summation of the multiple estimates of the individual reservoir resources. Under Section 5.2 of COGEH: Undiscovered Petroleum Initially-In-Place (equivalent to undiscovered resources) is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. There is no certainty that any portion of the undiscovered resources will be discovered and that, if discovered, it may not be economically viable or technically feasible to produce any of the resources,
(2) Estimates are as of July 1, 2009, the effective date of the Ryder Scott Report.

Based upon their review of the preliminary results from the re-entry and deepening of the Shenandoah-1 well, Ryder Scott Company – Canada provided correspondence dated October 23, 2009 that confirmed the findings in the above resource evaluation.

Future Operations

Following full evaluation of the results, the Company plans to test the well in the third quarter of 2010.

Under a work program approved by the Northern Territory of Australia Government, Department of Resources, on March 31, 2010, the Company is obligated to complete minimum work requirements by expending $6,400,000, $3,900,000 and $5,000,000 during the years ending December 31, 2010, 2011 and 2012, respectively, in order to continue to hold the underlying Permits in the Beetaloo Basin Project.

Canada

Falcon owns non-operating working interests in four producing natural gas wells in Alberta, Canada which do not comprise a material portion of Falcon's assets (the "**Hackett Interest**"). The Company does not anticipate any further exploration or development of the Hackett Interest.

Romania

In February 2008, JVX was contingently awarded the "Anina Concession". The award was subject to negotiation and finalization of a concession agreement for the acreage. A minimal work program was required under the Anina Concession, and the Company had the option to withdraw from the concession agreement at the end of each contract year. As of June 30, 2009, the Company determined that it will not proceed with any work program on the Anina Concession, and has charged to operations its entire carrying cost in the project.

Buckskin Mesa, Piceance Basin, US

On October 31, 2008, the Company consummated the acquisition of an undivided 25% working interest in five wells, including the 40-acre tract surrounding each well (collectively, the "**Five Wells**") from PetroHunter situated within PetroHunter's 20,000-acre Buckskin Mesa project located in the Piceance Basin, Colorado ("**Buckskin Mesa Project**"), and to undertake a testing and completion program in respect of the Five Wells pursuant to the terms of a Purchase and Sale Agreement (the "**Buckskin PSA**"). Under the terms of the Buckskin PSA, the Company agreed to pay 100% of the first $7,000,000 expended on testing and completion work in connection with the Five Wells. After performance of the testing and completion work, the Company had up to 60 days to review and analyze the results, at which time it could either retain its undivided 25% interest in the Five Wells and acquire no greater interest, or it could exercise an option (the "**Buckskin Mesa Option**") to acquire an additional undivided 25% working interest in the Five Wells (for a total of 50%) and a undivided 50% working interest in the remainder of the 20,000-acre Buckskin Mesa Project.

On February 24, 2009, the Company notified PetroHunter that it would not exercise the Buckskin Mesa Option. In accordance with the Second PSA, on June 11, 2009,the Company reassigned the undivided 25% working interest in the Five Wells to PetroHunter, and the Company was relieved of all obligations related to the Five Wells, including reclamation and plugging and abandonment obligations.

See also "*Transactions with Non-Arm's Length Parties and Related Parties*".

Karoo Basin, South Africa

On October 27, 2009, the Company secured a Technical Cooperation Permit (the "**TCP**") to evaluate the Karoo Basin in central South Africa. The Company has up to one year to conduct a technical appraisal of the area covered by the TCP, which does not include any well or seismic work obligations. At the end of the one year period, the Company has the option to apply for an exploration license covering all or a portion of the TCP upon the payment of $400,000. The TCP covers approximately 7.5 million acres and is located approximately 120 miles northeast of Cape Town, South Africa.

SELECTED ANNUAL INFORMATION

	2009	**2008**	**2007**
For the year ended December 31:			
Revenues	$ 69,000	$ 60,000	$ 207,000
Net loss	(63,928,000)	(35,911,000)	(12,847,000)
Loss per share	(0.107)	(0.063)	(0.027)
Cash dividend per share	Nil	Nil	Nil
As of December 31:			
Total assets	242,999,000	298,702,000	308,865,000
Long-term liabilities	10,137,000	5,285,000	5,140,000

2009 compared with 2008

The Company reported a net loss of $63,928,000 ($0.107 per share) for 2009 as compared to a net loss of $35,911,000 ($0.063 per share) for 2008. Significant changes between the 2009 and 2008 year were as follows:

	Year Ended December 31,		**Change**	
	2009	**2008**	**$**	**%**
Investor relations	$ 1,190,000	$ 610,000	$ (580,000)	(95.1)%
Payroll and related costs	3,668,000	2,908,000	(760,000)	(26.1)%
Stock based compensation	5,452,000	8,481,000	3,029,000	35.7%
Writedown of inventory available for sale	1,559,000	2,610,000	1,051,000	40.3%
Interest expense	879,000	-	(879,000)	
Interest income	(333,000)	(1,548,000)	(1,215,000)	(78.5)%
Impairment of petroleum and natural gas properties	45,045,000	6,970,000	(38,075,000)	(546.3)%
Foreign exchange	(2,573,000)	5,273,000	7,846,000	148.8%
Other	9,041,000	10,607,000	1,566,000	14.8%
Net loss	$ 63,928,000	$ 35,911,000	$(28,017,000)	78.0%

2008 compared with 2007

The Company reported a net loss of $35,911,000 ($0.063 per share) for 2008 as compared to a net loss of $12,847,000 ($0.027 per share) for 2007. Significant changes between the 2008 and 2007 year were as follows:

	Year Ended December 31,		**Change**	
	2008	**2007**	**$**	**%**
Stock based compensation	$ 8,481,000	$ 3,458,000	$ 5,023,000	145.3%
Impairment of petroleum and natural gas properties	6,970,000	847,000	6,123,000	722.9%
Foreign exchange	5,273,000	(7,987,000)	13,260,000	166.0%
Other	15,187,000	16,529,000	(1,342,000)	(8.1)%
Net loss	$ 35,911,000	$ 12,847,000	$ 23,064,000	179.5%

See also *"Overview of Business and Overall Performance"* and *"Results of Operations"*.

RESULTS OF OPERATIONS

Management's Discussion and Analysis of Financial Condition and Results of Operations for the Year Ended December 31, 2009 as Compared to the Year Ended December 31, 2008

This review of the results of operations should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2009 and 2008. The following is a summary of those results:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Change $	Change %
Petroleum revenue	$ 69,000	$ 60,000	$ 9,000	15.0%
Direct costs				
Production costs	43,000	34,000	(9,000)	(26.5)%
Depreciation, depletion and accretion	357,000	378,000	21,000	5.6%
	400,000	412,000	12,000	2.9%
Costs and expenses				
Accounting	766,000	852,000	86,000	10.1%
Depreciation and amortization	485,000	450,000	(35,000)	(7.8)%
Consulting	1,279,000	1,459,000	180,000	12.3%
Director fees	258,000	258,000	-	0.0%
Investor relations	1,190,000	610,000	(580,000)	(95.1)%
Legal costs	1,448,000	1,553,000	105,000	6.8%
Office and administrative	2,697,000	2,544,000	(153,000)	(6.0)%
Payroll and related costs	3,668,000	2,908,000	(760,000)	(26.1)%
Stock-based compensation	5,452,000	8,481,000	3,029,000	357.2%
Travel and promotion	1,988,000	2,309,000	321,000	13.9%
Writedown of inventory available for sale	1,559,000	2,610,000	1,051,000	40.3%
	20,790,000	24,034,000	3,244,000	13.5%
Other income (expense)				
Interest expense	(879,000)	-	(879,000)	
Interest income	333,000	1,548,000	(1,215,000)	(78.5)%
Impairment of petroleum and natural gas properties	(45,045,000)	(6,970,000)	(38,075,000)	(546.3)%
Gain (loss) on foreign exchange	2,573,000	(5,273,000)	7,846,000	148.8%
Other income (expense)	211,000	(368,000)	579,000	157.3%
	(42,807,000)	(11,063,000)	(31,744,000)	(286.9)%
Loss before income taxes	(63,928,000)	(35,449,000)	(28,479,000)	(80.3)%
Provision for income taxes	-	(462,000)	462,000	100.0%
Net loss and comprehensive loss	$ (63,928,000)	$ (35,911,000)	$(28,017,000)	(78.0)%

Petroleum Revenue

Of the revenue from petroleum and natural gas sales, $30,000 in 2009 and nil in 2008 were from the production of the Magyarcsanad-1 well in Hungary. The remainder of the revenue, $39,000 in 2009 and $60,000 in 2008, was derived from the sale of natural gas from the Hackett Interests. The Company has not yet realized revenue from its planned operations, and has incurred significant expenditures in connection with its exploration for petroleum and natural gas.

Costs and expenses

General and administrative costs, exclusive of the impact from depreciation and amortization, stock based compensation and write down of inventory available for sale, increased $801,000 to $13,294,000 from $12,493,000 in 2008. The increase was primarily due to the Company's activities in the Beetaloo Basin, Northern Territory, Australia. The significant components of changes in general and administrative expenses in 2009, as compared to 2008, were as follows:

- Investor relations – the increase was attributable to increased activities related to the convertible debt offering in 2009 and annual general meetings during the fourth quarter of 2009.

- Payroll and related costs – the increase was attributable to the retention of additional personnel to work on the Beetaloo Basin Project, and the employment of an individual who previously rendered services to the Company as a consultant.

- Stock based compensation (calculated utilizing the Black-Scholes option-pricing model) – the decrease was attributable to the value of options granted during 2008 as compared to no options granted during 2009. During 2008, the Company granted officers, directors, employees and consultants of the Company options to purchase 13,610,000 Common Shares at exercise prices ranging from $0.98 (CDN$1.00) to $1.19 (CDN$1.18). The options vest 20% at the date of grant, and 20% annually thereafter, and expire in May 2013.

- Writedown of inventory available for sale – inventory available for sale consists of drill pipe, casing and tubing. During the year ended December 31, 2008, $3,675,000 was reclassified from petroleum and natural gas properties to inventory available for sale, and the Company received $4,995,000 from the sale of inventory available for sale at the approximate carrying value of such inventory. At December 31, 2008, the Company charged to operations $2,610,000 as a write down to the carrying cost of the inventory to estimated net realizable value of $6,852,000 (61% of the original cost basis).

  During the year ended December 31, 2009, the Company received $497,000 from the sale of inventory available for sale at the approximate carrying value of such inventory; and transferred $600,000 of inventory available for sale from TXM to Falcon Australia. This inventory is reflected as petroleum and natural gas properties at December 31, 2009. At December 31, 2009, the Company charged to operations $1,559,000 as a write down to the carrying cost of the inventory to estimated net realizable value of $4,196,000 (48% of the original cost basis).

Impairment of petroleum and natural gas properties

As of December 31, 2009, the Company determined that the carrying value of the Hungarian petroleum and natural gas properties exceeded its estimated fair value. Consequently, during the fourth quarter of 2009, the Company reflected an impairment of petroleum and natural gas properties of $45,000,000 in its consolidated statement of operations, with a corresponding reduction to petroleum and natural gas properties in the consolidated balance sheet as of December 31, 2009.

During 2009, the Company also reflected an impairment of $45,000 to the carrying value of its Romanian property. The impairment resulted from the decision not to pursue its interest in the Anina Concession, the Company's sole petroleum and natural gas property located in Romania.

During 2008, the Company reflected impairment to the carrying value of its United States properties. The impairment resulted from an election not to exercise the Buckskin Mesa Option, the Company's sole petroleum and natural gas property located in the United States.

Other income (expense)

- Interest expense – the increase was attributable to the Company's financing activities resulting in the completion of the Offering (as defined below) in June 2009, and reflects primarily the accretion of the equity component of the convertible debentures. Statutory interest on the convertible debentures of $340,000 and amortization of deferred financing costs of $124,000 (total of $464,000) were capitalized to petroleum and natural gas properties, specifically the Beetaloo Basin Project.

- Interest income – the decrease was attributable to a reduction in the cash available for investment and the interest rate earned on the investments.

- Gain (loss) on foreign exchange – during 2009, the gain on foreign exchange was primarily due to the payment of obligations for operating activities in Hungary during a period when the value of the Hungarian forint was declining relative to the US dollar. During the year ended December 31, 2008, the loss on foreign exchange was attributable to foreign exchange movements on Canadian denominated cash accounts, primarily attributable to the decline in the value of the Canadian dollar relative to the US dollar.

  The value of the US dollar remained relatively static throughout the first half of 2008 relative to the value of the Canadian dollar; thereafter, and through the first quarter of 2009, the US dollar strengthened. Since then, the US dollar has weakened throughout the remainder of the year.

  The value of the US dollar weakened relative to the Hungarian forint throughout the first half of 2008; thereafter, and through the first quarter of 2009, the US dollar strengthened. Since then, the US dollar has weakened throughout the remainder of the year, with slight strengthening during December 2009.

  Substantially all of the Company's financings have been in Canadian dollars; commensurate with the weakening of the US dollar, the Company changed the composition of its cash balances to 16% in US dollars, 77% in Canadian dollars, 6% in Hungarian forints, nil in Euros and 1% in Australian dollars at December 31, 2009; a significant portion of the Company's operations are in Hungarian forints. The increase in the Canadian dollar cash balance relative to the total cash balance resulted from the proceeds from the unit offering discussed below, and the reduction of the US dollar cash balance as monies were used to fund the drilling of the Shenandoah-1 well.

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the eight most recently completed quarters:

As of:	**March 31, 2009**	**June 30, 2009**	**September 30, 2009**	**December 31, 2009**
Total assets	$298,830,658	$294,000,253	$292,435,351	$242,999,051
Petroleum and natural gas properties	237,757,364	245,704,299	250,348,187	207,889,291
Working capital	29,051,915	33,156,259	27,514,066	18,175,441
Total shareholders' equity	278,793,568	282,903,353	280,973,242	230,178,690
For the three months ended:	**March 31, 2009**	**June 30, 2009**	**September 30, 2009**	**December 31, 2009**
Revenue	11,091	9,157	7,184	41,113
Net income (loss)	(3,788,342)	(3,693,105)	(4,769,636)	(51,677,321)
Net income (loss) per share-basic and diluted	(0.006)	(0.006)	(0.009)	(0.086)

As of:	**March 31, 2008**	**June 30, 2008**	**September 30, 2008**	**December 31, 2008**
Total assets	$293,967,511	$297,373,735	$306,870,814	$304,472,067
Petroleum and natural gas properties	231,956,676	211,927,213	240,329,003	237,020,325
Working capital	51,593,669	68,343,352	55,312,512	32,073,983
Total shareholders' equity	285,082,821	281,874,148	297,268,936	281,190,721
For the three months ended:	**March 31, 2008**	**June 30, 2008**	**September 30, 2008**	**December 31, 2008**
Revenue	18,420	25,165	22,671	(6,509)
Net income (loss)	(4,375,025)	(7,486,272)	(6,104,178)	(17,945,358)
Net income (loss) per share-basic and diluted	(0.008)	(0.013)	(0.011)	(0.031)

The Company is a development stage company; it has limited revenue which is not material. As well, the Company's net income (loss) and net income (loss) per share relate to the Company's operations during a particular period, and are not seasonal in nature. Generally, the Company's total assets, petroleum and natural gas properties, working capital and total shareholders' equity fluctuate in proportion to one another until such time as the Company completes additional financing.

LIQUIDITY AND CAPITAL RESOURCES

Unit Offering

On June 30, 2009, the Company completed a unit offering, on a best efforts basis, pursuant to a short form prospectus filed with the securities regulatory authorities in the provinces of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Nova Scotia and New Brunswick, of 11,910 units at a price of $865 (CDN$1,000) per unit (the "**Offering**") for gross proceeds of $10,302,000 (CDN$11,910,000). Each unit consisted of one 11% convertible unsecured debenture in the principal amount of $779 (CDN$900) (each, a "**Debenture**") that matures on the fourth anniversary of its issuance, and 250 common shares in the capital of Falcon (the "**Unit Shares**") (collectively a "**Unit**"). The Debentures contain certain automatic and optional conversion features, as well as certain redemption features.

The Offering was conducted by an independent agent (the "**Agent**"). The Agent and members of the selling group were paid a cash commission of $644,000 (CDN$744,000), equal to 6.25% of the aggregate gross proceeds of the Offering, and received 1,250,550 non-transferrable warrants (the "**Agent Warrants**") to purchase Falcon common shares, based on an amount equal to 6% of the sum of the Unit Shares and the shares issuable upon conversion of the Debentures. Each Agent Warrant will entitle the holder thereof to acquire one Falcon common share for a period of two years following the closing of the Offering, at an exercise price of $0.52 (CDN$0.60) per share.

The Company expects to use the net proceeds from the Offering as determined and approved by Falcon's board of directors.

Falcon Australia Private Placement

In January 2010, Falcon Australia commenced the marketing, by way of a private placement, of the sale of up 50 million shares of its common stock ("**FA Share**") to sophisticated or professional investors within the meaning of sections 708(8) and 708(11) of the Corporations Act 2001(Australia) pursuant to an Offer Memorandum (the "**Offer**"), at a price of $1.00 per FA share, with an attached option. Each option entitles the holder to acquire one additional FA Share in respect of each FA Share sold, exercisable at $1.25 for a period of three years from date of issue. Closing is expected to occur on or about June 30, 2010, and as of April 23, 2010 all conditions precedent, including consent from the Northern Territory government for the transfer to Falcon Australia of the remaining undivided 25% working interest from Sweetpea to Falcon Australia, have been satisfied. The acting broker to the private placement will receive, as a brokerage fee, 6.50% of the funds raised, together with options (on the same terms as issued to investors), calculated at 6.50% of the number of shares issued in the private placement.

Going Concern

For the year ended December 31, 2009, the Company incurred a net loss of $63,928,000 and, as at December 31, 2009, had a deficit accumulated during the development stage of $137,922,000 and working capital of $18,176,000. The Company has been focused on securing equity financing and joint venture funding for its operations in the Beetaloo Basin Project and joint venture funding for its operations in the Makó Trough. The Company's ability to continue as a going concern is dependent upon its ability to raise additional capital to fund its operations, and ultimately to achieve profitable operations through the discovery of economically recoverable reserves.

Working Capital

Cash and cash equivalents at December 31, 2009 were $11,804,000, a decrease of $13,743,000 from $25,547,000 at December 31, 2008. Working capital at December 31, 2009 decreased to $18,176,000 from $32,074,000 at December 31, 2008.

The decrease to cash and cash equivalents of $13,743,000 was attributable to cash used in operating activities and investing activities (primarily for capital expenditures, including payment of prior year's accounts payable incurred for petroleum and natural gas properties) of $12,264,000 and $11,443,000, respectively, offset by cash provided by financing activities and the effect of exchange rates on cash of $8,863,000 and $1,101,000, respectively. Of the restricted cash of $1,184,000 at December 31, 2009, $1,020,000 is for one year of escrowed debenture interest as required under the Offering.

Amounts Receivable

Amounts receivable at December 31, 2009 were $2,955,000, which includes $856,000 receivable from joint interest owners ($668,000 for amounts due under a services agreement between the Company and ExxonMobil, and $188,000 for amounts recoverable from a joint interest owner for Australian GST), $961,000, $132,000 and $38,000 receivable from the Hungarian, Australian and Canadian governments as refunds of VAT, GST and GST, respectively, $350,000 for amounts receivable from the sale of inventory available for sale, and other of $618,000 (of which $469,000 is for operator bonds due from the Australian government).

Accounts Payables and Accrued Expenses

Accounts payable and accrued expenses at December 31, 2009 were $2,683,000, which includes $770,000 for capital expenditures related primarily to the Company's Hungarian and Australian operations, as compared to accounts payable and accrued expenses of $12,227,000 at December 31, 2008, which includes $624,000 for capital expenditures related primarily to the Company's Hungarian operations.

Capital Expenditures

For the year ended December 31, 2009, capitalized additions to petroleum and natural gas properties were $15,192,000, of which $5,734,000 was for the acquisition of an additional 25% interest in the Beetaloo Basin Project. During 2009, cash payments on all petroleum and natural gas properties were $8,836,000, of which $624,000 represented amounts incurred and reflected in accounts payable and accrued expenses at December 31, 2008.

For the year ended December 31, 2008, the Company incurred $39,410,000 for additions to its petroleum and natural gas properties, of which $25,890,000 and $748,000 were for the acquisition of working interests in the Beetaloo Basin Project and the Buckskin Mesa Project, respectively; and made cash payments on all petroleum and natural gas properties of $32,679,000 of which $12,517,000 and $1,000,000 represented amounts incurred and reflected in accounts payable and accrued expenses, and property contract payable, respectively, at December 31, 2007. Included in additions to petroleum and natural gas properties for the Beetaloo Basin Project were previously issued special warrants of Falcon, valued at $20,000,000, that were converted into 28,888,888 Common Shares on December 29, 2008.

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Hungary

As of December 31, 2009, the Company's net cumulative expenditures for the Production License and Exploration Licenses, including the acquisition, seismic testing, drilling of exploratory wells, and initial testing and completion of wells, was approximately $213,528,000**,** including an asset retirement obligation of approximately $4,583,000 for the six wells drilled by the Company and $394,000 for the well drilled by ExxonMobil.

The significant costs incurred during 2009 in Hungary were for well maintenance for the six existing well bores. The significant costs for 2008 were for specialized processing and evaluation of the seismic and well data previously acquired in 2007 and well maintenance for the six existing well bores.

The Company's future capital requirements for Hungary will be dependent upon, among other things, the evaluation of the Hungarian properties. The Company will continue to evaluate the potential for further activity in the Makó Trough in both the Production License and Exploration Licenses. The Company's requirements for additional capital are dependent upon its future operating plans.

Australia

The significant costs incurred during 2009 in Australia were for the acquisition of the additional 25% working interest in the Beetaloo Basin Project, and exploration costs, including tubular and drill pipe, related to the Company's re-entry into the Shenandoah-1 well. There were no exploration costs during 2008 in Australia.

The Company's activity in Australia for 2009, prior to becoming operator on the Beetaloo Basin Project in June 2009, was focused on administrative matters. In July 2009, exploration activities commenced with the re-entry into the previously drilled Shenandoah-1 well. The Company's proportionate share of the costs incurred for re-entry under the Joint Operating Agreement with PetroHunter was $4,975,000 through December 31, 2009.

The Company's future capital requirements for Australia will be dependent upon the evaluation of the results of the Shenandoah-1 well and the overall Beetaloo Basin Project.

Furniture and Equipment

Furniture and equipment at December 31, 2009 was $3,390,000 as compared to $3,165,000 at December 31, 2008.

The availability of debt and equity capital, and the price at which additional capital could be issued will be dependent upon the success of the Company's exploration activities, and upon the state of the capital markets generally.

Legal Matters

The Company may, from time to time, be involved in various claims, lawsuits, disputes with third parties, actions involving allegations of discrimination, or breach of contract incidental to the operations of its business. Except for the following-described dispute, the Company is not currently involved in any claims, disputes, litigation, or other actions with third parties which it believes could have a materially adverse effect on its financial condition or results of operations.

On November 10, 2009, the Company was served with a Complaint by a former vendor of TXM (the "**Vendor**"), claiming that the Company owes the Vendor approximately $3,200,000 plus interest, arising out of a dispute related to TXM's alleged failure to pay for certain oilfield equipment. Falcon and TXM have advised the Vendor, and continue to assert, that the claim is without merit and that they intend to vigorously defend against it as well as make any appropriate counter claims against the Vendor.

Transactions with Non-Arm's Length Parties and Related Parties

The Company has entered into certain agreements and transactions with PetroHunter, a non-arm's length party for the purposes of the TSXV, whose largest single shareholder is also the President and CEO of the Company. The Company acquired working interests from PetroHunter in the Beetaloo Basin Project and the Buckskin Mesa Project.

Beetaloo Basin Project

On September 30, 2008, Falcon and Falcon Australia consummated the acquisition of an undivided 50% working interest in the Beetaloo Basin Project with PetroHunter. On June 11, 2009, pursuant to the Second PSA, the Company completed the acquisition of an additional undivided 25% working interest in the Beetaloo Basin Project. Under the terms of the Second PSA, the principal consideration paid by the Company for the acquisition was the exchange of the $5,000,000 note receivable from PetroHunter. In addition, the Company paid certain vendors who had provided goods or rendered services for the Beetaloo Basin Project, prior to the Company's acquisition of its 50% interest in September 2008, in exchange for inventory and operator bonds of approximately the same value, and has relinquished its rights to the unexpended testing and completion funds of approximately $874,000. On closing of this transaction, the Company became operator of the Beetaloo Basin Project, and PetroHunter and the Company entered into an escrow agreement governing the release of all remaining Falcon common shares previously issued to PetroHunter.

On December 7, 2009, Falcon and Falcon Australia entered into an Agreement with PetroHunter and Sweetpea, wherein Falcon Australia will issue to Sweetpea l common shares of Falcon Australia in consideration for the transfer of Sweetpea's undivided 25% working interest in the Permits. The Company will enter into a MSA related to the operations of the Permits. Under the terms of the Agreement, Falcon will be issued 150 million shares of Falcon Australia for conversion of a portion ($30,000,000) of Falcon Australia's debt payable to Falcon, which approximates Falcon's initial acquisition cost previously paid to Sweetpea for the 75% working interest in the Permits held by Falcon Australia as of the date of the Agreement, and Sweetpea will be issued 50 million shares of Falcon Australia for its remaining 25% working interest in the Permits. On April 23, 2010, Falcon Australia received notice from the Department of Resources, Northern Territory Government, that the registration of the transfer of the remaining 25% interest in the Permits was completed, satisfying all conditions precedent to closing

Buckskin Mesa Project

On October 31, 2008, the Company consummated the acquisition of an undivided 25% working interest in the Buckskin Mesa Project. Under the Buckskin PSA, the Company agreed to pay 100% of the first $7,000,000 of testing and completion work to be undertaken in connection with the Five Wells. After performance of the testing and completion work, the Company had up to 60 days to review and analyze the results, at which time it could either retain its 25% interest in the Five Wells and acquire no greater interest, or it could exercise the Buckskin Mesa Option to acquire an additional undivided 25% working interest in the Five Wells (for a total of 50%) and an undivided 50% working interest in the remainder of the 20,000-acre Buckskin Mesa Project. On February 24, 2009, the Company notified PetroHunter that it would not exercise the Buckskin Mesa Option. Of the $7,000,000 advanced to PetroHunter, approximately $874,000 had not been expended. On June 11, 2009, pursuant to the Second PSA, the Company relinquished its rights to the unexpended testing and completion funds, and reassigned the undivided 25% working interest in the Five Wells to PetroHunter. The Company was relieved of all obligations related to the Five Wells, including reclamation and plugging and abandonment obligations.

Services – Directors and Officers

During 2009, the Company incurred $180,000 (2008-$180,000) to a current director of the Company, Dr. György Szabó, for advisory and consulting services rendered to TXM; and $156,000 (2008- $175,000) in consulting fees to a current director of the Company, Mr. Daryl Gilbert, for advisory and consulting services rendered to Falcon.

David Brody, the Company's Corporate Secretary, is a partner of Patton Boggs LLP, a US law firm that provides US legal advice to the Company. The Company has not recorded any amounts paid to Patton Boggs LLP as transactions with a related party because Mr. Brody has not received any remuneration from Patton Boggs LLP since his appointment as Corporate Secretary of Falcon.

DISCLOSURE OF OUTSTANDING SHARE DATA

The following is a summary of the Company's outstanding share data as at December 31, 2009 and April 29, 2010:

Class Of Securities	December 31, 2009	April 29, 2010
Common Shares	602,216,801	602,216,801
Stock Options(1)	41,975,000	26,475,000
June Agents' Warrants(2)	1,250,550	1,250,550

Notes:

(1) On April 2, 2010, options to acquire 15,500,000 Common Shares at $0.25 per Common Share expired.
(2) Warrants to purchase 1,250,550 Common Shares at a price of $0.52 (CDN$0.60) per Common Share were issued to the agents in June 2009 in connection with the Offering, and expire on June 30, 2011.

OFF-BALANCE SHEET ARRANGEMENTS AND PROPOSED TRANSACTIONS

The Company does not have any off-balance sheet arrangements or proposed transactions, other than operating leases.

CRITICAL ACCOUNTING POLICIES

Management is often required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. Following is a discussion of the accounting estimates that are critical in determining the Company's financial results.

Full cost accounting

The Company follows the full cost method of accounting for petroleum and natural gas operations, whereby all costs relating to the exploration and development of petroleum and natural gas reserves are capitalized on a country-by-country cost centre basis. Such costs include land acquisition costs, costs of drilling both productive and non-productive wells, well equipment, flow line and facility costs, geological and geophysical expenses and overhead expenses directly related to exploration and development activities. Gains or losses on sales of properties are recognized only when crediting the proceeds to the recorded costs would result in a change of 20% or more in the depletion and depreciation rate. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development costs are amortized using the unit-of-production method based on estimated proved reserves of petroleum and natural gas before royalties as determined by independent petroleum engineers. Changes in estimated proven reserves or future development costs have a direct impact on depletion and depreciation expense.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned to them. If proved reserves are assigned to the properties, the costs are included in the depletion calculation. Similarly, if assets are determined to be impaired, any applicable write-downs are charges to depletion expense.

Petroleum and natural gas reserves

Estimates of petroleum and natural gas reserves are projections based on geological and engineering data. There are uncertainties inherent in these projections, including the interpretation of data and the projection of future rates of production and the timing of developmental expenditures. Reserve engineering is an analytical process of estimating below ground accumulations of petroleum and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. The Company's proved petroleum and natural gas reserves are evaluated and reported on annually by an independent petroleum-engineering consultant. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to a number of uncertainties and various interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion. A revision to the reserves estimate could result in a higher or lower depreciation, depletion and amortization ("**DD&A**") charge to net earnings. Downward revisions to reserve estimates could also result in a write-down of petroleum and natural gas property, plant and equipment under the ceiling test described below.

At December 31, 2009, the Company had proved reserves for the Hackett Interests.

Ceiling test

The carrying value of property, plant and equipment is reviewed each quarter for impairment. Impairment will occur when the carrying amount of the property, plant and equipment minus the sum of the undiscounted cash flows expected to result from the Company's proved reserves yields a negative result. The cash flows are calculated based on third party quoted forward prices and adjusted for the Company's contract and/or hedged prices as well as quality differentials. If there were impairment, the magnitude of it would be calculated by comparing the carrying amount of property, plant and equipment to the estimated net present value of future cash flows from proved plus risked probable reserves. A risk-free interest rate is used to arrive at the net present value of future cash flows. Any excess carrying value above the net present value of future cash flows would be recorded as a permanent impairment and charged as additional depletion expense in the statement of operations.

For the year ended December 31, 2009, no impairment was required for the Company's petroleum and natural gas properties in Australia and Canada; however, the Company did require impairment of its Hungarian and Romanian properties.

Asset retirement obligations

The Company recognizes the fair value of asset retirement obligations ("**ARO**") in the period in which they are incurred and when a reasonable estimate of fair value can be made. The obligations recognized are estimates of statutory, contractual or legal obligations that the Company will reasonably be expected to incur and then discounted to its present value using the Company's credit adjusted risk-free interest rate. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and the amount of this accretion is charged to earnings in the period through charges to accretion expense. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the ARO. Any difference between the actual costs incurred upon settlement of the ARO and the recorded liability is recognized as a gain or loss in the Company's earnings in the period in which the settlement occurs. Determination of the original undiscounted costs is based on engineering estimates using current costs in accordance with existing legislation and industry practice. The estimation of these costs can be affected by factors such as the number of wells drilled, well depth, estimated future salvage values, location of the well and current environmental legislation.

At December 31, 2009, the Company has recorded an ARO for the Beetaloo Basin Project, the Hackett Interest and the seven exploratory wells in Hungary.

Future income tax

The Company follows the asset and liability method of accounting for income taxes. Under this method the Company records future income tax assets and liabilities based on "temporary differences" (differences between the accounting basis and the tax basis of the assets and liabilities) and are measured using the currently enacted, or substantively enacted tax rates and laws expected to apply when these differences reverse. The effect of a change in substantively enacted income tax rates on future income tax assets and liabilities is recognized in income in the period that the change occurs.

Stock based compensation

The Company has a stock based compensation plan enabling officers, directors and employees to purchase common shares at exercise prices equal to the market price on the date the option is granted. The Company uses the fair value method for valuing stock option grants. Compensation costs attributable to share options granted are measured at their fair value at the grant date and expensed over the expected exercise time period with a corresponding increase to contributed surplus. Upon exercise of the stock options, the consideration paid by the option holder, together with the amount previously recognized in contributed surplus, is credited to share capital. The assumptions used in calculating its stock based compensation expense are: the volatility of the stock price, risk-free rates of return and the expected lives of the options given that some will be forfeited upon termination of employment.

Foreign currency

The United States dollar is our reporting currency in all of the Company's areas of operations: Australia, Canada, Hungary, and United States. The Australian dollar, the Canadian dollar, the Hungarian forint and the United States dollar are the functional currencies. The Company attempts to manage its operations in such a manner as to reduce its exposure to foreign exchange losses. However, there are many factors that affect foreign exchange rates and resulting exchange gains and losses, many of which are beyond the Company's influence. It is not possible to predict the extent to which the Company may be affected by future changes in exchange rates.

CHANGES IN ACCOUNTING POLICIES

Goodwill and intangible assets

Effective on January 1, 2009, the Company adopted Section 3064, "Goodwill and intangible assets" ("**Section 3064**"). Section 3064 replaces Sections 3062 "Goodwill and other intangible assets" and Section 3450 "Research and development costs". Section 3064 establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets including internally developed intangible assets. The adoption of Section 3064 did not have a significant effect on the Company's consolidated financial statements.

Credit risk and fair value of financial assets and liabilities

In January 2009, the Canadian Institute of Chartered Accountants ("**CICA**") issued EIC-173, "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". The EIC provides guidance on how to take into account credit risk of an entity and counterparty when determining the fair value of financial assets and financial liabilities. This standard was applied by the Company effective January 1, 2009 and did not have a significant effect on the Company's consolidated financial statements.

Financial instruments – recognition and measurement

During 2009, the CICA amended Section 3855 "Financial Instruments – Recognition and Measurement". This revised standard was applied by the Company effective for the year ended December 31, 2009, and the application did not have a significant effect on the Company's consolidated financial statements.

Financial instruments – disclosures

During 2009, the CICA amended Section 3862, "Financial Instruments – Disclosures", which requires enhanced disclosures of the fair values of financial instruments. Financial instruments recognized at fair value on the consolidated balance sheet must now be classified in fair value hierarchy levels based on their valuations. This revised standard was applied by the Company effective for the year ended December 31, 2009.

NEW CANADIAN ACCOUNTING STANDARDS

The Accounting Standards Board ("**AcSB**") of the CICA has issued new accounting standards that the Company is required to consider for adoption, as follows:

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

The CICA issued three new accounting standards in January 2009: Section 1582, Business Combinations ("**Section 1582**"), Section 1601, Consolidated Financial Statements ("**Section 1601**"), and Section 1602, Non-controlling Interests ("**Section 1602**"). These new standards will be effective for fiscal years beginning on or after January 1, 2011. The Company is in the process of evaluating the requirements of the new standards.

Section 1582 replaces Section 1581, Business Combinations, and establishes standards for the accounting for a business combination. It provides the Canadian equivalent to International Financial Reporting Standard IFRS 3 – Business Combinations. The section applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011.

Sections 1601 and 1602 together replace Section 1600, Consolidated Financial Statements. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1601 applies to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011. Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. It is equivalent to the corresponding provisions of International Financial Reporting Standard IAS 27 – Consolidated and Separate Financial Statements and applies to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011.

International Financial Reporting Standards

The AcSB has determined that Canadian accounting standards for publicly-listed companies will converge with International Financial Reporting Standards ("**IFRS**") effective for interim and annual periods beginning on or after January 1, 2011. The adoption of IFRS in 2011 will require restatement for comparative purposes of figures presented for the 2010 fiscal year. The Company understands there may be material differences between Canadian GAAP and IFRS, and is therefore monitoring this project with a view to understanding the possible future effects of the transition to IFRS.

No other new accounting policies were adopted by the Company during the year ended December 31, 2009, and the Company is not expected to adopt any new accounting policies in 2010.

International Financial Reporting Standards

The Company will be required to adopt IFRS for its interim and annual consolidated financial statements effective January 1, 2011. The transition date of January 1, 2011 will require the restatement for comparative purposes of all quarterly results reported by the Company for the year ended December 31, 2010, as well as an opening IFRS consolidated balance sheet as of January 1, 2010.

During 2010, the Company commenced an initial diagnostic review of the significant differences between IFRS and Canadian GAAP, in order to identify areas that could significantly impact the Company's financial reporting. In many areas, the Company's policies and transition elections may impact the effect that the conversion to IFRS will have on the Company's financial reporting. As such, during 2010 the Company began the process of evaluating and selecting appropriate accounting policies and determining the transition elections it plans to use. As a result of the above process, the Company expects the following areas could be significantly impacted by the Company's transition to IFRS:

Petroleum and natural gas properties

Adoption of IFRS may significantly impact the Company's accounting policies for petroleum and natural gas properties. For Canadian GAAP purposes, the Company follows the full cost method of accounting as prescribed by Accounting Guideline 16. Application of the full cost method of accounting is discussed in the "Critical Accounting Estimates" section of this MD&A. Significant differences in accounting for petroleum and natural gas properties between IFRS and Canadian GAAP include the following:

- Pre-exploration costs must be expensed. Under the full cost method of accounting, these costs are currently included in the country cost centre.

- Exploration and evaluation costs will be initially capitalized as exploration and evaluation assets. Once technical feasibility and commercial viability of reserves is established for an area, the costs will be transferred to petroleum and natural gas properties. If technically feasible and commercially viable reserves are not established for a new area, the costs must be expensed. Under the full cost method of accounting, exploration and evaluation costs are currently disclosed as petroleum and natural gas properties, but withheld from costs subject to DD&A. Costs are transferred to costs subject to DD&A when proved reserves are assigned or when it is determined that the costs are impaired.

- DD&A of producing properties will be at an asset level. Under full cost method of accounting, DD&A of petroleum and natural gas properties is on a country cost centre basis.

- Interest directly attributable to the acquisition or construction of a qualifying asset must be capitalized to the cost of the asset. Under Canadian GAAP, capitalization of interest is discretionary.

- Impairment of petroleum and natural gas properties will be tested at a cash generating unit level (the lowest level at which cash inflows can be identified). Under the full cost method of accounting, impairment is tested at the country cost centre level.

Impairment of long-lived assets other than petroleum and natural gas properties

Under Canadian GAAP, when events or changes in circumstances indicate that a long-lived asset may be impaired, the carrying value is compared to both the net recoverable amount (being net cash flows calculated on an undiscounted basis) and fair value. Where the carrying amount is greater than either of these amounts, an impairment equal to the difference between the carrying amount and fair value is recognized in earnings.

Under IFRS, impairment is assessed using a one-step process which compares the carrying amount to the recoverable amount, calculated as the greater of the value in use, being the estimated discounted future expected pre-tax cash flows, and fair value less costs to sell, of the asset being tested. Impairment may result from the use of the one-step process under IFRS where no impairment exists under the two-step process required by Canadian GAAP.

Under IFRS, an impairment loss is recognized for the difference between the carrying amount and the greater of value in use and fair value less costs to sell of a long-lived asset. Reversals of impairment losses are recognized in the periods the reversals occur. When an impairment loss reverses in a subsequent period, the carrying amount of the related long-lived asset is increased to the revised estimate of recoverable amount to the extent that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss be recognized for the asset previously. Reversal of impairment losses is not permitted under Canadian GAAP.

Measurement of reclamation and closure cost obligations

Under IFRS, the Company’s obligation for reclamation and closure costs is measured based on management’s best estimate of future expenditures required to settle the obligation at the balance sheet date, discounted using the applicable country-specific risk free rates. Under Canadian GAAP, this obligation is measured based on the fair value of future estimated expenditures using quoted market prices where applicable, discounted using the Company’s credit-adjusted risk free rate.

Property and equipment

Under IFRS, the Company will be required to apply componentization concepts to its property and equipment, and will be required to perform an annual review of the estimates of useful lives, residual values and depreciation methods, in addition to the annual review for impairment. The Company expects to use only the historical cost accounting method to value its assets under IFRS.

Provisions and contingencies

Under IFRS, contingent assets and liabilities must be assessed in legal and constructive terms and are required to be recognized if they are probable (defined as 'more likely than not' or greater than 50%). The Company continues to assess its provisions and contingencies under the terms of this standard.

Presentation and disclosure

The presentation, including disclosures, of the Company's consolidated financial statements will change as a result of implementing the IFRS presentation and disclosure requirements. These changes could result in significant differences in the presentation of the Company's consolidated balance sheet, statement of operations, shareholders' equity and cash flows. In addition, it is expected that the Company will disclose additional information in the notes to the consolidated financial statements in order to comply with the requirements of IFRS.

Taxes

The Company expects differences in the accounting for income taxes and continues to assess the potential impact under IFRS.

Accounting processes, internal controls procedures, and information technology systems

During 2010, the Company also performed a high level analysis of the impact of IFRS on the Company's accounting processes, internal controls procedures, and information technology systems. Based on this review, management has identified certain matters that will require prospective attention.

During 2010, the Company plans to complete some of the key activities related to the conversion, including the following:

- Prepare the opening consolidated balance sheet as of January 1, 2010;
- Draft the consolidated financial statements and notes thereto;
- Determine the accounting policies and transition elections;
- Consult with the Company's subsidiaries regarding the transition; and
- Obtain appropriate training for the Company's staff.

The Company has informed the audit committee of management's plans and decisions to date, and the Company plans to continue to provide the audit committee with updates through 2010 as the conversion project progresses.

Business Risks and Uncertainties

As stated above and as discussed in the Company's continuous disclosure documents, certain risks and uncertainties that could cause the Company's actual results to materially differ from our current expectations include, but are not limited to:

- The Company's business is at a similar stage to that of a recently formed company with no operating history, which makes it difficult to evaluate its business prospects;
- The Company cannot be certain that it will continuously meet all requirements to maintain the Production License;
- The Company cannot be certain that current expected expenditures and completion/testing programs will be realized;
- The Company will have substantial capital requirements that, if not met, may hinder its growth and operations;
- The Company might not be able to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them, which could cause the Company to incur losses;
- The Company might incur debt in order to fund its exploration and development activities, which would continue to reduce its financial flexibility and could have a material adverse effect on the Company's business, financial condition or results of operation;
- Shortages of rigs, equipment, supplies and personnel could delay or otherwise adversely affect the Company's cost of operations or its ability to operate according to its business plans;
- Resource estimates depend on many assumptions that may turn out to be inconclusive, subject to varying interpretations, or inaccurate;
- The value of the Common Shares might be affected by matters not related to the Company's own operating performance for reasons that include the following:
    - general economic conditions in Australia, Canada, Hungary, the United States and globally;
    - industry conditions, including fluctuations in the price of petroleum and natural gas;
    - governmental regulation of the petroleum and natural gas industry, including environmental regulation;
    - fluctuation in foreign exchange or interest rates;
    - liabilities inherent in petroleum and natural gas operations;
    - geological, technical, drilling and processing problems;
    - unanticipated operating events which can reduce production or cause production to be shut-in or delayed;
    - failure to obtain third party consents and approvals, when required;
    - stock market volatility and market valuations;
    - competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel;

  - the need to obtain required approvals from regulatory authorities;
  - Hungarian and worldwide supplies and prices of and demand for petroleum and natural gas;
  - political conditions and developments in Hungary and Australia;
  - political conditions in petroleum and natural gas producing regions;
  - revenue and operating results failing to meet expectations in any particular period;
  - investor perception of the petroleum and natural gas industry;
  - limited trading volume of Common Shares;
  - change in environmental and other governmental regulations;
  - announcements relating to the Company's business or the business of its competitors;
  - the Company's liquidity; and
  - the Company's ability to raise additional funds.
- The Company might not be able to obtain necessary approvals from one or more Hungarian and/or Australian government agencies, surface owners, or other third parties;
- Drilling for and producing petroleum and natural gas are high-risk activities with many uncertainties that could adversely affect the Company's business, financial condition or results of operations;
- Competition in the petroleum and natural gas industry is intense, and many of the Company's competitors have greater financial, technological and other resources than the Company does, which may adversely affect its ability to compete;
- Political instability or fundamental changes in the leadership or in the structure of the governments in the jurisdictions in which the Company operates could have a material negative impact on the Company;
- Market conditions or operation impediments may hinder the Company's access to petroleum and natural gas markets or delay its production;
- A substantial or extended decline in petroleum and natural gas prices may adversely affect the Company's ability to meet its capital expenditure obligations and financial commitments;
- The Company may enter into currency hedging agreements but may not be able to hedge against all such risks;
- The Company is subject to complex laws and regulations, including environmental regulations, which can have a material adverse effect on the cost, manner or feasibility of doing business;
- The loss of the Company's chief executive officer or other of the Company's key management and technical personnel or its inability to attract and retain experienced technical personnel could adversely affect the Company's ability to operate;
- The Company does not insure against all potential operating risks. It might incur substantial losses and be subject to substantial liability claims of its petroleum and natural gas operations; and

- To the extent that the Company establishes petroleum and natural gas reserves, it will be required to replace, maintain or expand its petroleum and natural gas reserves in order to prevent its reserves and production from declining, which would adversely affect cash flows and income.

Should one or more of these risks materialize, or should the Company's underlying assumptions prove incorrect, the Company's actual results may materially differ from the Company's current expectations. Therefore, in evaluating forward-looking statements, readers should specifically consider the various factors that could cause the Company's actual results to materially differ from such forward-looking statements.

Management's Responsibility for MD&A

The information provided in this MD&A, is the responsibility of management. In the preparation of this MD&A, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgments and have been properly reflected in this MD&A.

The audit committee has reviewed the MD&A with management, and has reported to the Board of Directors. The Board of Directors has approved the MD&A as presented.