Falcon Oil & Gas Ltd.

Form 51-102F1
Management's Discussion & Analysis
For the Three Months and Year Ended 31 December 2012

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INTRODUCTION

The following management's discussion and analysis (the "**MD&A**") was prepared as at 12 April 2013 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 three months and year ended 31 December 2012. This MD&A should be read in conjunction with the audited consolidated financial statements for the year ended 31 December 2012 and 2011.

The information provided herein in respect of Falcon includes information in respect of its wholly-owned subsidiaries: Mako Energy Corporation ("**Mako**"), a Delaware 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; Falcon Oil & Gas Ireland Ltd ("**Falcon Ireland**"), an Irish company; Falcon Oil & Gas USA Inc., a Colorado company and its 72.7% majority owned subsidiary, Falcon Oil & Gas Australia Limited ("**Falcon Australia**"), an Australian company (collectively, the "**Company**" or the "**Group**").

Additional information related to the Company, including the Company's Annual Information Form ("AIF") for the year ended 31 December 2011 dated 30 April 2012 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. The company's AIF for the year ended 31 December 2012 will be filled on or prior to 30 April 2013.

Forward-looking statements

Forward-looking statements include, but are not limited to, statements with respect to: the focus of capital expenditures; Falcon's acquisition strategy; the criteria to be considered in connection therewith and the benefits to be derived therefrom; Falcon's goal to sustain or grow production and reserves through prudent management and acquisitions; the emergence of accretive growth opportunities; Falcon'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 Falcon's petroleum and natural gas properties; realisation of the anticipated benefits of acquisitions and dispositions; Falcon's ability to establish a broad institutional shareholder base in London and Dublin and increase the volume of trading in common shares; expectations regarding the ability of Falcon to access additional sources of funding not currently available; and Falcon's ability to leverage its experience in the unconventional oil and gas industry to acquire interests in licenses.

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 Republic of Hungary, the Commonwealth of Australia, the Republic of South Africa 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 Falcon's AIF dated 31 December 2011. Risks and uncertainties that could cause Falcon's actual results to materially differ from current expectations are disclosed in this document. The forward-looking statements contained in this document are expressly qualified by this cautionary statement. Falcon disclaims any intention or obligation to update or revise any forward-looking statements whether as a result of new information, future events or otherwise, except as required under applicable securities regulation.

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

RPS Energy CPR Report

The RPS Energy CPR Report, dated 1 January 2013 (which is referenced in this document), entitled "Evaluation of the Hydrocarbon Resource Potential Pertaining to Certain Acreage Interests in the Beetaloo Basin, Onshore Australia and Mako Trough, Onshore Hungary" (the "**Report**") can be found at www.sedar.com. The Report on the hydrocarbon resource potential of the Beetaloo Basin and the Mako Trough describes a possible distribution of the un-risked prospective (recoverable) portion of un-risked undiscovered original oil and gas in-place resources, as defined by the Canadian Oil and Gas Evaluation Handbook ("**COGEH**") and does not represent an estimate of reserves. The Report has been prepared in accordance with the Canadian standards set out in the COGEH and is compliant with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities." 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.

Dollar Amounts

All dollar amounts below are in United States dollars, except as otherwise indicated. CDN$ where referenced represents Canadian Dollars; £/ Stg where referenced represents British Pounds sterling, HUF where referenced represents Hungarian Forint and A$ where referenced represents Australian dollars.

The financial information provided herein has been prepared in accordance with International Financial Reporting Standards ("**IFRS**").

OVERVIEW OF BUSINESS AND OVERALL PERFORMANCE

About the Company

Falcon is an international oil and gas company engaged in the acquisition, exploration and development of unconventional and conventional oil and gas assets. The Company's interests are located in internationally diversified countries that are characterised by a high regional demand for energy and are close to existing infrastructure allowing rapid delivery of oil and gas to market. In each territory, the Company is partnered with a large, credible multinational energy company.

Falcon's strategy is to leverage the Group's expertise in the unconventional oil and gas industry to acquire interests in licences covering large acreages of land and to build on its internationally diversified portfolio of unconventional assets and interests, which are located in countries that the Board of Directors of Falcon (the "Board") believes support the exploitation of unconventional oil and gas. Falcon seeks to add value to its assets by entering into farm-out arrangements with major oil and gas companies that will fully or partially carry Falcon through seismic and drilling work programmes. The Group's principal interests are located in two major underexplored basins in Australia and South Africa and in Hungary, covering approximately 14.75 million gross acres in total.

Falcon is incorporated in British Columbia, Canada and headquartered in Dublin, Ireland with a technical team based in Budapest, Hungary. Falcon's Common Shares are traded on the TSX Venture Exchange (symbol: FO.V); AIM, the market operated by the London Stock Exchange (symbol: FOG) and ESM, the market regulated by the Irish Stock Exchange (symbol: FAC).

Information on the Group's assets

The following table summarises the principal oil and gas interests of the Group in Australia, South Africa and Hungary:-

Assets (Country)	Interest (%)	Operator	Status	Area (km^2)	Expiry
Exploration Permit EP-76 (Beetaloo Basin, Northern Territory, Australia)	72.7[(i)]	Hess[(iv)]	Exploration	4,976.3	31 December 2013
Exploration Permit EP-98 (Beetaloo Basin, Northern Territory, Australia)	72.7[(i)]	Hess[(ii) (iv)]	Exploration	11,412.1	31 December 2013
Exploration Permit EP-99 (Beetaloo Basin, Northern Territory, Australia)	72.7[(i)]	Falcon Australia	Exploration	2,587.2	31 December 2013
Exploration Permit EP-117 (Beetaloo Basin, Northern Territory, Australia)	72.7[(i)]	Hess[(iv)]	Exploration	9,218.3	31 December 2013
Technical Cooperation Permit, (Karoo Basin, South Africa)	100	Falcon	TCP	30,327.9	In Force[(iii)]
Makó Production Licence (Makó Trough, Hungary)	100	TXM	Production	994.6	21 May 2042

Notes:
(i) Falcon owns 72.7% of Falcon Australia, which holds a 100% interest in the Beetaloo Exploration Permits. Of the remaining 27.3% of Falcon Australia, 24.2% is owned by Sweetpea, a wholly owned Australian subsidiary of PetroHunter Energy Corp. and 3.1% interest is held by others.
(ii) Falcon Australia retains operatorship in the Shenandoah-1 well and approximately 405 km2 (approximately 100,000 acres) land around the Shenandoah-1 well-bore in exploration permit EP-98.
(iii) In compliance with the terms of the Technical cooperation permit ("TCP"), the Company submitted its application for an exploration permit in August 2010 prior to the moratorium being introduced in April 2011. Local counsel has confirmed that despite the TCP expiry date of October 2010 having passed, the Company's interests remain valid and enforceable.
(iv) Falcon Australia entered into a joint venture with Hess Australia (Beetaloo) Pty Ltd. ("Hess") in 2011.

Beetaloo Basin, Northern Territory, Australia

Overview
Falcon Australia, Falcon's 72.7% owned subsidiary, is the registered holder of four exploration permits, comprising approximately 7 million acres (approximately 28,000 km2) in the Beetaloo Basin, Northern Territory, Australia. The Beetaloo Basin is located 600 kilometres south of Darwin close to infrastructure including a highway, two pipelines and a railway, offering transport options to the Australian market and beyond via the existing and proposed LNG capacity in Darwin.

The Beetaloo Basin is a Proterozoic and Cambrian tight oil and gas basin. In its entirety, the Beetaloo Basin covers approximately 8.7 million acres (approximately 35,260 km2) and is a relatively underexplored onshore exploration basin with, as far as the Company is aware, 11 exploration wells drilled in the Beetaloo Basin to date. The area is remote and sparsely populated and the Board believes that it is well suited for oil and gas projects. Australia has a developed resources industry with a stable political, legal and regulatory system.

RPS Energy, in its independent Competent Persons Report ("CPR") dated 1 January 2013 (filed on SEDAR in January 2013 and available on the Falcon website), estimates gross unrisked recoverable prospective resource (play level) potential of 162 trillion cubic feet of gas ("Tcf") of gas and 21,345 million barrels of oil ("Mmbo") (P50) for Falcon Australia's Beetaloo Exploration Permits.

Exploration Permits
A summary of Falcon Australia's Beetaloo Exploration Permits is contained in the table above. The acreage interests covered by the Beetaloo Exploration Permits cover the majority of the Beetaloo Basin and are held 100% in the name of Falcon Australia.

In April 2011, Falcon Australia entered into a joint venture with Hess whereby Hess agreed to collect seismic data over an area made up of three of the four Beetaloo Exploration Permits, excluding exploration permit EP-99 and an area within exploration permit EP-98 (the Shenandoah-1 well and approximately 100,000 acres (approximately 405 km2) of land around the well-bore), referred to as the Hess Area of Interest. Falcon Australia is the operator of exploration permit EP-99 and Hess is the operator of exploration permits EP-76, EP-98 and EP-117. Falcon Australia also retained operatorship in the Shenandoah-1 well and approximately 100,000 acres (approximately 405 km2) of land around the Shenandoah-1 well-bore within exploration permit EP-98. The work commitments for the Beetaloo Exploration Permits held by Falcon Australia have been met for previous years, with the exception of exploration permit EP-99, on which an extension was granted to 31 December 2013. In September 2012, Falcon Australia obtained Northern Territory Department of Resources approval for a 12 month extension of the Beetaloo Exploration Permits until 31 December 2013.

In accordance with local law and regulations, all Falcon Australia's acreage interests are subject to royalties on production values of up to approximately 12% to government and native title holders/claimants and up to approximately 13% to other parties. In addition, Falcon Australia is subject to Commonwealth Government corporation tax of 30%, and to the Commonwealth Government's Petroleum Resource Rent Tax ("PRRT") levied at the rate of 40% on the taxable profits derived from the petroleum projects. The PRRT is calculated on the individual projects and royalties are deductible for PRRT purposes. The PRRT tax system is separate from the company income tax system and is based on cash flow. Both royalties and PRRT are deductible for corporate income tax purposes.

Discoveries and Prospectivity
The Board believes that the Beetaloo Basin is relatively under-explored and has shale oil, shale gas and BCGA ("basin centered gas accumulations") potential. As far as the Company is aware, 11 wells have been drilled in the Beetaloo Basin to date. This work was undertaken by a Rio Tinto Group subsidiary company exploring for conventional hydrocarbons and while not leading to a conventional development, the data from the cores demonstrated the presence of tight oil and gas and several horizons were shown to be prospective for unconventional oil and gas.

There are no existing fields but there are numerous mudlog and core oil and gas shows throughout the Beetaloo Basin in prospective formations. The Shenandoah-1 well was a vertical hole well drilled by Sweetpea in 2007. The well was deepened by Falcon Australia in 2009 to finish at 2,714 metres. It was re-entered in Q3 2011 and five short tests were conducted including several fraccing operations. Gas was recovered from three zones with some liquids.

Current activity
Hess paid Falcon Australia an initial sum of $17.5 million on signing the Hess Agreement and since then Hess has acquired 3,490 kilometres of 2D seismic data at an estimated cost in excess of $55 million. The 2D seismic data is currently being processed and interpreted. Hess has the option, valid until 30 June 2013, to acquire a 62.5% working interest in the Hess Area of Interest by committing to drill and evaluate five exploration wells at Hess' sole cost, one of which must be a horizontal well. All costs to plug and abandon the five exploration wells will also be borne solely by Hess. The Board estimates that the gross costs associated with the five-well programme will be approximately $75 million. Hess has agreed, subject to proceeding to the development phase, to carry Falcon Australia, on the first development well, up to a gross cost of $10 million, which the Board believes will be the total gross cost of this well. Costs to drill wells after the five exploration wells and the first development well (and after the initial $10 million) will be borne 62.5% by Hess and 37.5% by Falcon Australia.

Under the minimum work commitments for exploration permit EP-99, Falcon Australia must spend a minimum of $1.5 million by 31 December 2013 in collecting 2D seismic data on the underlying acreage within exploration permit EP-99.

Falcon Australia is currently finalising a 2D seismic acquisition programme for exploration permit EP-99 in order to meet this requirement in 2013. This 2D seismic data is expected to provide the necessary information to plan a potential well programme in the coming years.

Falcon Australia intends to meet this commitment either through a farm-out arrangement or through its own resources. Falcon Australia has received expressions of interest from a number of third parties regarding a possible farm-out arrangement on the combined area outside of the Hess Area of Interest comprising exploration permit EP-99 and approximately 100,000 (approximately 405 km2) acres around the Shenandoah-1 well, measuring approximately 739,388 acres (approximately 2,992 km2) in total. The Board estimates that the gross costs associated with the initial drilling programme on the combined area outside of the Hess Area of Interest will be between $25-$50 million.

Karoo Basin, South Africa

Overview

The Company holds a Technical Co-operation permit ("TCP") covering an area of approximately 7.5 million acres (approximately 30,327 km2), in the southwest Karoo Basin, South Africa, which grants the Company exclusive rights to apply for an exploration right over the underlying acreage. In August 2010, the Company submitted an application to the Petroleum Agency of South Africa for an exploration right over the acreage covered by the TCP and, as part of the application process, the Company submitted an environmental management plan in January 2011.

On 1 February 2011, the Minister of Mineral Resources (the "Minister") published a notice in the Government Gazette declaring a moratorium on the processing of all new applications relating to the exploration and production of shale gas in the Karoo Basin. This moratorium did not extend to existing applications, such as Falcon's, that were submitted prior to 1 February 2011. In April 2011, the Minister announced a further moratorium, which was not officially declared in terms of a notice in the Government Gazette, prohibiting all new applications and suspending the processing of all pending application whilst the South African Department of Mineral Resources conducted an environmental feasibility study on the effects of hydraulic stimulation and developed a system to regulate onshore exploration activities (the "Undeclared Moratorium"). The Undeclared Moratorium has no legal effect since it is a requirement of the South African petroleum legislation that all such moratoriums be published in the Government Gazette. In September 2012, the South African Government announced a decision to lift the Undeclared Moratorium on shale gas exploration. The Minister has indicated that although the Undeclared Moratorium has been "lifted", pending exploration right applications will not be processed and awarded until the regulations regarding hydraulic fracturing have published. These regulations are expected to be published in Q2 2013. Consequently, the Board expects that the exploration right over the acreage will be awarded in the second half of 2013.

The South African Government is entitled to a royalty on the sale of mineral resources of up to 7% of gross sales (in the case of unrefined resources) and 5% of gross sales (in the case of refined resources, such as oil and gas). The Liquid Fuels Charter provides that an oil and gas company must reserve not less than 9% for Historically Disadvantaged South Africans ("HDSA") to buy-in to any offshore production right granted. On the advice of South African counsel, the Board believes that the HDSA buy-in will also apply to onshore production rights in South Africa, including any right granted pursuant to the TCP. Similarly, the State has an option to acquire an interest of up to 10% in any production right granted. However, it is not required to pay any consideration for its 10% interest or contribute to past costs, but must contribute *pro rata* in accordance with its interest towards production costs going forward.

Corporation tax in South Africa is imposed at a rate of 28% of taxable income. Dividends tax is imposed on the shareholder at a rate of 15%.

Discoveries and Prospectivity

In its entirety, the Karoo Basin is approximately 173 million acres (approximately 700,000 km2) in size located in central and southern South Africa and contains thick, organic rich shales such as the Permian Whitehill Formation. The Karoo describes a geological period lasting some 120 million years and the rocks laid down during that period of time, covering the late Paleozoic to early Mesozoic interval. These were deposited in a large regional basin and resulted in the build-up of extensive deposits.

Until recently, the Karoo Basin was not considered prospective for commercial hydrocarbons resulting in very limited modern hydrocarbon exploration onshore in South Africa. In an independent report dated April 2011, the U.S. Energy Information Administration ("EIA") estimated that there are 485 Tcf technically recoverable resources in the Karoo Basin which would rank it fifth in the world after China, USA, Argentina and Mexico for shale gas potential. In particular the Permian Ecca group contains three potential shales identified as having potential for shale gas. The shale in the Whitehall Formation, in particular, is ubiquitous, has a high organic content and is thermally mature for gas.

Current activity
In December 2012, Falcon entered into an exclusive cooperation agreement with Chevron to jointly seek unconventional exploration opportunities in the Karoo Basin. The Chevron Agreement provides for Falcon to work exclusively with Chevron for a period of five years to jointly seek to obtain exploration rights in the Karoo Basin subject to the parties mutually agreeing participation terms applicable to each right. As part of the Chevron Agreement, Chevron made a cash payment to Falcon of $1 million in February 2013 as a contribution to past costs.

Makó Trough, Hungary

Overview
Falcon has been active in the Makó Trough since 2005 when it acquired two exploration licences, the Makó and the Tisza exploration licences. Between 2005 and 2007, Falcon pursued a work programme consisting of the acquisition of 1,100 km2 of 3D seismic data and a six-well drilling programme. Each of the six wells encountered thick sequences of hydrocarbon bearing rocks, and tests flowed hydrocarbons from each tested horizon. In 2007, Falcon's subsidiary, TXM, was awarded the 35-year Makó Production Licence which covers some of the acreage originally covered by the Makó and the Tisza exploration licences.

Hungary is an established oil and gas producing country. The Makó Production Licence is in the vicinity of the largest producing field in Hungary, the MOL Group owned and operated Algyö field, which has produced approximately 2.5 Tcf and 220 Mmbo to date. The Makó Production Licence is located approximately ten kilometres to the east of the MOL Group owned and operated Algyö field and is transected by existing gas pipelines and infrastructure, including a 12 kilometre gas pipeline built by Falcon in 2007, together offering transport and potential access to local markets and larger distribution centres for international markets.

Makó Production Licence
The Makó Production Licence was granted by the Hungarian Mining Authority over a gas exploration project in the Makó Trough, located in south-eastern Hungary. The lands within the Makó Production Licence were formerly part of the Group's two hydrocarbon exploration licences – the Tisza exploration licence and the Makó exploration licence.

The Makó Production License covers approximately 245,775 acres (approximately 1,000 km2) and is held 100% by TXM, a wholly owned subsidiary of the Group. Under the terms of the Makó Production Licence, the Group is obliged to pay a 12% royalty to the Hungarian Government on any unconventional production and has a further 5% royalty payable under an agreement with Prospect Resources Inc., the previous owners of the acreage covered by the Makó Production Licence. Corporate profits are taxed at 19%. In 2009, an additional profit based energy industry tax, levied on energy supplying companies, was introduced. The rate was originally set at 8% but, as part of Hungary's third package of austerity measures, the rate has increased to 31% from 2013, with deductions allowable for certain capital expenditures. TXM is the operator and there are no outstanding work commitments on the Makó Production Licence.

Discoveries and Prospectivity

The Makó Trough contains two plays:
- a play targeting gas prospects in the shallower Algyö Play at depths between 2,300 metres and 3,500 metres; and
- a deeper unconventional play targeting significant contingent resources in the Deep Makó Trough.

The Algyö Play
The Algyö Play is a relatively shallow play of between 2,300 and 3,500 metres. A number of Falcon wells have been drilled through the Algyö Play in recent years, some of which encountered gas shows, but to date none of these wells tested the shallow play concept at an optimal location, as these wells targeted the Deep Makó Trough, at intervals of up to 6,000 metres. Multiple Algyö prospects have subsequently been identified by the Group through extensive AVO analysis, and 3D seismic data has shown the presence of possible gas zones above the Szolnok formation (part of the Deep Makó Trough). In total, ten prospects have been identified within the Algyö Play from which RPS Energy, in its independent CPR, estimates eight prospects contain gross unrisked recoverable prospective gas resources of 568 billion cubic feet ("Bcf") (P50).

In January 2013, Falcon agreed a three-well drilling exploration programme with NIS to target the Algyö Play, whereby NIS made a cash payment of $1.5 million to Falcon in February 2013, and agreed to drill three exploration wells by July 2014. NIS will earn, after undertaking the three-well drilling obligation, 50% of the net production revenues from the three wells drilled. The Board estimates that the gross costs of the three-well drilling programme will be approximately $21 million. In addition, NIS will have an option to acquire a right of first negotiation for future drilling operations in the Algyö Play, sharing any potential future costs and revenue with the Group, on terms to be negotiated, after paying Falcon $2.75 million. Falcon will be fully carried on the drilling and testing of three exploration wells and will retain 100% interest in the Deep Makó Trough.

The Deep Makó Trough
This is a deeper unconventional play targeting gas, and to a lesser extent oil, in the low permeability and low porosity rocks in the deeper horizons of the basin. RPS Energy in its independent CPR estimates gross recoverable contingent resources for the Deep Makó Trough of 35.3 Tcf of gas and 76.7 Mmbo of oil (P50).

Between 2005 and 2007, Falcon acquired 1,100 km2 of 3D seismic data and executed a six-well drilling programme on the Deep Makó Trough. Early exploration efforts focused on proving hydrocarbon potential and delineation of the basin in order to secure the Makó Production Licence. Each of the six wells encountered thick sequences of hydrocarbon bearing rocks, and tests flowed hydrocarbons from each tested horizon. Several wells flowed gas on test and one well, the Magyarcsanád-1, tested light oil. The deepest well was the Makó-7 which, along with the Makó-4, was not tested. The Makó-7 results demonstrated the presence of a very large column of hydrocarbons in the well-bore. In 2007, Falcon constructed a 12 kilometre gas pipeline which connected the Makó-6 and Makó-7 wells with a MOL operated pipeline, offering potential access to local and international markets. The Company plans to re-enter the untested Makó-7 and Makó-4 wells and will seek a technically and financially capable partner to test and produce the shale gas and tight gas formations in the Deep Makó Trough. The Board estimates that the gross costs of re-entering and testing the Makó-7 and Makó-4 wells will be approximately $25 million.

Current Activity
Drilling preparations are already underway in the Algyö Play. NIS has informed the Company that it expects the first well to spud by the end of Q2 2013 and the three-well drilling programme to be completed before the end of 2013.

Alberta, Canada

For the 12 months ended 31 December 2012, Falcon had revenue of $13,000 (2011: $31,000) which was earned from non-operating working interests in three producing, and one recently shut-in, natural gas wells located in Alberta, Canada. Falcon does not anticipate any further exploration or development of these wells and no further material revenue is expected to be generated or material costs incurred.

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SELECTED ANNUAL INFORMATION

(In thousands of $ unless otherwise indicated)	2012	2011	2010
For the year ended 31 December:			
Revenues	21	33	28
Net loss	(17,715)	(34,827)	(150,784)
Loss per share - cent	(0.03)	(0.05)	(0.25)
Cash dividend per share	Nil	Nil	Nil
At 31 December:			
Total assets	86,013	94,901	115,409
Long-term liabilities	16,247	17,937	11,604

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RESULTS OF OPERATIONS

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 31 December 2012 and 2011.

Management's Discussion and Analysis of Financial Condition and Results of Operations for the Year Ended 31 December 2012 as compared to the Year Ended 31 December 2011

The Company reported a net loss of $17.7 million for 2012 as compared to a net loss of $34.8 million for 2011. Changes between the 2012 and 2011 year were as follows:

(In thousands of $)	Year Ended 31 December		Change	
	2012	**2011**	**$**	**%**
Revenue				
Oil and natural gas revenue	21	33	(12)	(36)
Expenses				
Exploration and evaluation expenses	(1,654)	(1,629)	(25)	2
Production and operating expenses	(37)	(34)	(3)	9
Depletion and depreciation	(342)	(368)	26	(7)
Impairment of non-current asset	-	(26,035)	26,035	(100)
General and administrative	(6,206)	(7,703)	1,497	(20)
Write down of AFS inventory	(552)	(641)	89	(14)
Share based compensation	(2,380)	(2,435)	55	(2)
Restructuring expense	(792)	-	(792)	(100)
Other income	276	543	(267)	(49)
Reversal of litigation expense	-	1,533	(1,533)	(100)
Fair value (loss) / gain – warrants in issue	(2,019)	4,213	(6,232)	(148)
	(13,706)	(32,556)	18,850	(58)
Finance (expense) / income				
Interest income on bank deposits	66	83	(17)	(21)
Derivative gains (unrealised)	15	734	(719)	(97)
Effective interest on loans and borrowings	(3,721)	(2,429)	(1,292)	53
Accretion of decommission provision	(209)	(267)	58	(22)
Net foreign exchange loss	(181)	(425)	244	(58)
	(4,030)	(2,304)	(1,726)	74
Net loss and comprehensive loss	(17,715)	(34,827)	17,112	(49)
Net loss and comprehensive loss attributable to:				
Common shareholders	(17,441)	(34,561)	17,120	
Non-controlling interest	(274)	(266)	(8)	
Net loss and comprehensive loss	(17,715)	(34,827)	17,112	

Oil and Natural Gas Revenue
Oil and natural gas revenue of $21,000 (2011: $33,000) includes sale of natural gas from the Hackett Interests in Alberta, Canada of $13,000 in 2012 (2011: $31,000) and $8,000 in 2012 (2011: $2,000) for production from the exploratory wells in Hungary. The Company has not yet realised revenue from its planned operations elsewhere, and has incurred significant expenditures in connection with its exploration for oil and natural gas.

Exploration and evaluation expenses
In December 2012, Falcon entered into an exclusive cooperation agreement with Chevron to jointly seek unconventional exploration opportunities in the Karoo Basin. The Chevron Agreement provides for Falcon to work exclusively with Chevron for a period of five years to jointly seek to obtain exploration rights in the Karoo Basin subject to the parties mutually agreeing participation terms applicable to each right. As part of the Chevron Agreement, Chevron made a cash payment to Falcon of $1 million in February 2013. This receivable has been included within exploration and evaluation expenses. Excluding this remittance, exploration and evaluation expenses increased by $1 million to $2.7 million in 2012 from $1.6 million in 2011. The increase in expenses primarily relate to Hungarian properties. These expenses were incurred for the recurring maintenance, and testing of wells while the Company pursued the joint venture partnership with Naftna industrija Srbije jsc ("NIS"), the 56% Gazprom Group company.

Depletion and depreciation
Included in depletion and depreciation for 2012 is an accelerated charge of $0.1 million of depreciation associated with assets that were impacted by the decision to relocate the Company's headquarters from Denver, Colorado to Dublin, Ireland. This was offset by a reduced annual deprecation relating to the Group's other property plant and equipment.

Impairment of non current assets
As at 31 December 2011, the Company determined that the carrying value of the Hungarian exploration and evaluation assets and the Canadian natural gas interests exceeded their estimated fair value. Consequently, in 2011, the Company reflected an impairment of Hungarian exploration and evaluation assets of $26 million and an impairment of the Canadian natural gas properties of $35,000.

No similar charge has been reflected in the current year financial statements as the Company has determined that there are no indicators of impairment present in accordance with IFRS 6 "Exploration for and evaluation of mineral interests".

General and administrative costs

(In thousands of $)	**Year Ended 31 December**		**Change**	
	2012	**2011**	**$**	**%**
General and Administrative costs				
Accounting and Audit fees	(703)	(876)	173	(20)
Consulting fees	(966)	(1,108)	142	(13)
Investor relations	(127)	(125)	(2)	2
Legal fees	(479)	(713)	234	(33)
Office and Administrative costs	(1,231)	(1,559)	328	(21)
Payroll and related costs	(1,873)	(2,336)	463	(20)
Directors fees	(306)	(199)	(107)	54
Travel and promotion	(521)	(787)	266	(34)
	(6,206)	**(7,703)**	**1,497**	**(20)**

General and administrative costs decreased $1.5 million to $6.2 million in 2012 from $7.7 million in 2011. The significant components of changes in general and administrative expenses in 2012 as compared to 2011 were as follows:

- Accounting and audit fees: The decrease occurred due to reduced audit and accounting fees in 2012 in comparison with 2011 as 2011 includes first time fees associated with the implementation of IFRS and higher audit fees. This was not repeated in 2012.
- Consulting and Legal fees: The decrease was attributable to a continued decrease in the use of outside consultants and counsel and increased focus on cost containment by new management during the year.
- Office and Administrative: The decrease was attributable to a decrease in occupancy costs associated with the Denver office due to its closure during Q3 2012 and an overall reduction in operating overhead costs.
- Payroll and related cost: The decrease was attributable due to the closure of the Denver office in Q3, 2012 and the resulting reduction in the management team.
- Directors' fees increased during the year due to the rebasing of director fees in line with the market.
- Travel and promotion decreased in the current year over the prior year due to the closure of the Denver office in Q3, 2012 and increased focus by new management on cost containment.

Writedown of inventory available for sale
Inventory available for sale consists of drill pipe, casing and tubing. The Group assessed the carrying value of its inventory as at 31 December 2012. It was determined, given the age and condition of the inventory, that it was appropriate to impair this to zero.

Share based compensation
Share based compensation decreased by $25,000 to $2.4 million in 2012. During 2012, an amount of $1.1 million was recognised as share based compensation due to the accounting modification (as prescribed by IFRS 2 "Share based payments") of options previously granted to employees and consultants being terminated as a result of the decision to relocate the corporate headquarters.

This increase was offset by a reduction in the grant date fair value of 2012 grants relative to the fair value of prior grants.

During the year ended 31 December 2012, the Company granted 6 million options at an exercise price of $0.10 (CDN$0.10) (2011: 17.8 million at $0.15 (CDN$0.15)) per share. Of the options granted during 2012, all vest 1/3 ratably at the anniversary date over three years, and have an expiry date of 1 May 2017. Of the options granted during the year ended 31 December 2011, all vest 1/3 at the date of grant, with the remainder vesting ratably at the anniversary date over the two years thereafter. Eoin Grindley (Chief Financial Officer) is, pursuant to his employment contract, entitled to 3,000,000 stock options which have not yet been granted.

Restructuring expense
Restructuring expense of $0.7 million was recognised in 2012 as a result of the Company's decision to relocate its corporate headquarters from Denver, Colorado to Dublin, Ireland, and consists of severance and health benefits – $0.5 million and rent expense, net of sublease – $0.2 million. An additional $1.1 million was recognised as share based compensation due to the accounting modification (as prescribed by IFRS 2 "Share based payments") of options previously granted to employees and consultants being terminated as a result of the decision to relocate the corporate headquarters. Depreciation and depletion includes an additional $0.1 million related to furniture and equipment in the Denver office. The Denver office closed on 28 September 2012.

Reversal of litigation expense
As at 31 December 2010, the Company was a party to certain legal matters that it determined an appropriate estimate of the potential liability should be recorded should the Company not prevail. The 31 December 2010 financial statements included an obligation of $3.7 million with a corresponding charge to litigation expense, including interest and fees, related to this claim. In July 2011, the Company entered into a settlement agreement resulting in a decrease in the legal provision of $1.5 million.

Fair value (loss) / gain – warrants in issue
Fair value (loss) / gain – warrants in issue decreased from a gain of $4.2 million in 2011 to a loss of $2 million in 2012. The decrease occurred due to the changes in the fair value of derivative instruments. The primary variable was the favourable movement in the Falcon share price over the period.

Finance (expense) / income
Net Finance expense increased from $2.3 million in 2011 to $4 million in 2012, a movement of $1.7 million. The increase occurred primarily due to the increase in the effective interest rate on the issued debenture (due to maturity approaching in June 2013) of $1.3 million and an unfavourable movement in the fair value of the convertible debt conversion feature of $0.8 million (due to a favourable movement in Falcon's share price). This was offset by a favourable foreign exchange gain of $0.3 million.

Net loss attributable to non-controlling interest
The amounts reflected in 2012 and 2011 represent the share of Falcon Australia losses attributable to shareholders other than Falcon.

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Management's Discussion and Analysis of Financial Condition and Results of Operations for the Three Months Ended 31 December 2012 as Compared to the Three Months Ended 31 December 2011

The Company reported a net loss of $1.1 million for the three months ended 31 December 2012 as compared to a net loss of $29.4 million for corresponding period of 2011. Changes between the 2012 and 2011 were as follows:

(In thousands of $)	Three Months Ended 31 December		Change	
	2012	**2011**	**$**	**%**
Revenue				
Oil and natural gas revenue	9	9	-	-
Expenses				
Exploration and evaluation expenses	(93)	(691)	598	(87)
Production and operating expenses	(7)	(9)	2	(22)
Depletion and depreciation	(47)	(61)	14	(23)
Impairment of assets	-	(26,035)	26,035	(100)
General and administrative	(1,289)	(1,729)	440	(25)
Share based compensation	(176)	(441)	265	(60)
Writedown of inventory	(552)	(641)	89	(14)
(Reversal of) litigation expense	-	(121)	121	(100)
Restructuring expense	(118)	-	(118)	(100)
Other income	78	183	(105)	(57)
Fair value gain – warrants in issue	1,937	953	984	103
	(267)	(28,592)	28,325	(99)
Finance (expense) / income				
Interest income on bank deposits	13	21	(8)	(38)
Derivative gains (unrealised)	227	-	227	100
Effective interest on loans and borrowings	(1,032)	(706)	(326)	46
Accretion of decommission provision	(39)	(61)	22	(36)
Net foreign exchange gain/ (loss)	15	(32)	47	(147)
	(816)	(778)	(38)	5
Net loss and comprehensive loss	(1,074)	(29,361)	28,287	(96)
Net loss and comprehensive loss attributable to:				
Common shareholders	(988)	(29,308)	28,320	
Non-controlling interest	(86)	(53)	(33)	
Net loss and comprehensive loss	(1,074)	(29,361)	28,287	

Exploration and evaluation expenses
In December 2012, the Company entered into an exclusive cooperation agreement with Chevron to jointly seek unconventional exploration opportunities in the Karoo Basin. The Chevron Agreement provides for the Company to work exclusively with Chevron for a period of five years to jointly seek to obtain exploration rights in the Karoo Basin subject to the parties mutually agreeing participation terms applicable to each right. As part of the Chevron Agreement, Chevron made a cash payment to the Company of $1 million. This receivable has been included within exploration and evaluation expenses. Excluding the remittance exploration and evaluation expenses increased by $0.2 million to $0.9 million in the three months ended December 2012 from $0.7 million in the corresponding 2011 period. The increase in expenses primarily relate to Hungarian properties. These expenses were incurred for the recurring maintenance, and testing of wells while the Company pursued the joint venture partner with NIS.

Impairment of non current assets
As at 31 December 2011, the Company determined that the carrying value of the Hungarian exploration and evaluation assets and the Canadian natural gas interests exceeded their estimated fair value. Consequently, in 2011, the Company reflected an impairment of Hungarian exploration and evaluation assets of $26 million and an impairment of the Canadian natural gas properties of $35,000.

No similar charge has been reflected in the current year financial statements as the Company has determined that there are no indicators of impairment present in accordance with IFRS 6 “Exploration for and evaluation of mineral interests”.

General and administrative costs
General and administrative costs decreased $0.4 million to $1.3 million in the three months ended 31 December 2012 from $1.7 million in the corresponding 2011 period. The significant components of changes in general and administrative expenses in 2012 as compared to 2011 were as follows: Accounting and audit fees, a decrease of $119,000; Office and Admin expenses, a decrease of $339,000; Payroll costs a decrease of $268,000; Travel and promotion a decrease of $95,000 offset by an increase in legal and consulting fees of $302,000.

The overall decrease can be attributed to the closure of the Denver office during Q3 2012, reduced headcount and more focus on cost control by new management.

Writedown of inventory available for sale
Inventory available for sale consists of drill pipe, casing and tubing. The Group assessed the carrying value of its inventory as at the 31 December 2012. It was determined, given the age of the inventory that it was appropriate to impair this to zero.

Share based compensation
Share based compensation amounted to $176,000 in the three month period. This relates primarily to the 6 million options issued during the year and also the cost to the company of $54,000 in granting an ex-director shares in December 2012. This share grant was part of the director’s employment arrangements during his time in office.

Restructuring expense
Restructuring expense of $0.1 million was recognised in the quarter as a result of the Company’s decision to relocate its corporate headquarters from Denver, Colorado to Dublin, Ireland, and consists of severance and health benefits. The Denver office closed on 28 September 2012.

(Reversal of) litigation expense
As at 31 December 2010, the Company was a party to certain legal matters that it determined an appropriate estimate of the potential liability should be recorded should the Company not prevail. The 31 December 2010 financial statements included an obligation of $3.7 million with a corresponding charge to litigation expense, including interest and fees, related to this claim. In July 2011, the Company entered into a settlement agreement resulting in a decrease in the legal provision of $1.5 million.

Fair value (loss) / gain – warrants in issue
Fair value (loss) / gain – warrants in issue increased from a gain of $1 million in Q4 2011 to $1.9 million in Q4 2012. The movement occurred due to the changes in the fair value of derivative instruments. The primarily variable was the movement in the Falcon share price over the period September to December 2012 and period September to December 2011 respectively.

Finance (expense) / income
Net Finance expense increased by $38,000. The increase occurred primarily due to the increase in the effective interest rate on the issued debenture (due to maturity approaching in June 2013) offset and a favourable movement in the fair value of the convertible debt conversion feature (due to a downward movement in Falcon’s share price in Q4 2012).

Net loss attributable to non-controlling interest
The amounts reflected in 2012 and 2011 represent the share of Falcon Australia losses attributable to shareholders other than Falcon.

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BUSINESS RISKS AND UNCERTAINTIES

The risks and uncertainties identified below (and as discussed in the Company's continuous disclosure documents), are those which the Board believes to be material in relation to the Group but these risks may not be the only risks faced by the Group. Additional risks, including those that the Board is unaware of or those that are currently deemed not to be material, may also result in decreased income, increased expenses or could result in a decline in the value of Common Shares.

1. RISKS RELATING TO THE GROUP AND ITS BUSINESS

A decision by Hess not to exercise its option to acquire a 62.5% working interest in the Hess Area of Interest would have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

Under the terms of the Hess Agreement, Hess has the option until 30 June 2013 to acquire a 62.5% working interest in the Hess Area of Interest, by committing to drill and evaluate five exploration wells at Hess' sole cost, one of which must be a horizontal well. In the event that Hess decides not to drill and evaluate five wells, its obligations under the Hess Agreement will cease and Falcon Australia will become responsible for 100% of any exploration and development costs of the Hess Area of Interest. If Falcon Australia were unable to secure participation by a new farm-in or joint venture partner for the development of the Hess Area of Interest by 31 December 2013, its ability to develop and realise its investment in the asset could be significantly curtailed. A decision by Hess not to exercise its option would have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group may not be able to get the necessary approvals to operate its business

The Group might not be able to obtain necessary approvals from one or more Australian, South African or Hungarian government agencies, surface owners, or other third parties, for one or more of the following: surface use for seismic surveys; surface use for drilling activities; surface use for gathering lines, pipelines, or surface equipment; or commencing one or more wells.

Australia

Australian government agencies have discretion in interpreting various laws, regulations and policies, which govern operations in the Beetaloo Basin. Actions by Australian government agencies may affect the Company's operations including obtaining necessary approvals, land access, sovereign risk, regulatory risk, taxation and royalties which may be payable on the proceeds of the sale of any successful exploration.

Further, the approval of contractual arrangements in relation to exploration permits as well as the renewal of exploration permits are also matters of governmental discretion and no guarantee can be given in this regard.

In Australia, Aboriginal native title to land ("Native Title") has survived the Crown's acquisition of sovereignty. The Native Title Act 1993 (Commonwealth) and the complementary state Native Title legislation, regulates the recognition and protection of Native Title in Australia and, amongst other things, sets out the procedures to be followed in relation to certain "future acts" including the grant of petroleum tenements. The Company is required to obtain clearances, consents and approvals in relation to Native Title in connection with the Beetaloo Exploration Permits. Access may be restricted or subject to suitable arrangements being agreed and entered into (for example, compensation and access arrangements) in respect of areas the subject of Native Title. If the requisite approvals and consents are not obtained in respect of the Beetaloo Exploration Permits, there may be a material adverse effect on the Group's business, prospects, financial condition and results of operations.

South Africa

The processing of the company's South African application for an exploration right over the TCP acreage has been subject to delay as a result of a moratorium on shale gas exploration introduced in April 2011 by the South African Department of Mineral Resources. In September 2012, following the conclusion of a study on the effects of hydraulic stimulation and the development of a system to regulate onshore exploration activities, the moratorium as far as it relates to pending applications such as the company's application was "lifted".

However, it is expected that the company's exploration right application will only be finalised once regulations relating to hydraulic fracturing are published. These regulations are currently expected to be published in Q2 2013. Should the publication of these regulations be delayed, the decision to award Falcon an exploration right over the acreage may be delayed or, the company may be required to resubmit an application or risk losing its exclusive right to obtain an exploration right over the TCP acreage. This could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

Hungary
Hungarian government agencies have discretion in interpreting various laws, regulations, and policies governing operations under the Makó Production Licence. Further, the Group must enter into agreements with private surface owners to obtain access and agreements for the location of surface facilities. In addition, because Hungary enacted a new set of mining laws (which also govern oil and gas operations) in 1993, which have since been amended, there is only a relatively short history of the government agencies' handling and interpreting those laws, including the various regulations and policies relating to those laws. This short history does not provide extensive precedents or the level of certainty that allows the Group to predict whether such agencies will act favourably toward the Group.

Neither the Makó Production Licence nor Hungarian mining laws grant reasonable use of the surface across the geographical area covered by the Makó Production Licence. Instead, the licencee must obtain rights-of way from surface owners, including private landowners, for access and other purposes. The land owner must ensure that those engaging in mining operations make observations and measurements, lay cables, put up adequate signage, and take any other actions necessary. If the land owner and licencee cannot establish operations that meet their mutual agreement, a licencee may request and pay for an easement from the Hungarian government. The Hungarian government has discretion to interpret various requirements for the issuance of drilling permits, and there is no assurance that the Group will be able to meet all such requirements. Any inability of the Group to meet any such requirements could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

A decision by NIS, following the completion of the initial three well drilling programme in the Algyö Play, not to participate in any further drilling operations, would have a material adverse effect on the Group's business, prospects, financial condition and results of operations.
Under the terms of the NIS Agreement, NIS will earn 50% of the net production revenues from the initial three wells being drilled in the Algyö Play, and will have an option to acquire a right of first negotiation for future drilling operations in the Algyö Play, sharing any potential future costs and revenue with the Group, on terms to be negotiated. In the event that NIS decide not participate in any further drilling operations in the Algyö Play, Falcon will become responsible for 100% of any exploration and development costs in the Algyö Play under the Makó Production Licence. If the Group were unable to secure participation by a new farm-in or joint venture partner for the development of the Algyö Play, its ability to develop and realise its investment in the asset could be significantly curtailed. This could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

There is no guarantee that the Company has or will continue to have good title to assets.
Although title reviews have been and will continue to be performed according to standard industry practice prior to the acquisition of all oil and gas assets or rights to acquire leases in prospects and assets or the commencement of drilling wells, such reviews do not guarantee or preclude that an unidentified or latent defect in the chain of title will not exist, or that a third party claim will not arise that burdens, diminishes or defeats the claim of the Company which could impact the Company's ability to realise its investment in a particular asset and could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group cannot be certain that it will continue to meet all requirements to maintain its permits and licences
Falcon Australia is required to perform work programmes in order to maintain the Beetaloo Exploration Permits. In particular, under the minimum work commitments for exploration permit EP-99, Falcon Australia must spend a minimum of $1.5 million by 31 December 2013 in collecting 2D seismic data within exploration permit EP-99. To the extent that the Group cannot fulfil its requirements under exploration permit EP-99, it may have to request an extension and/or may be at risk of losing this exploration permit.

Hungarian Mining Law requires that the Group file annual plans of development ("Plans") with regards to the Makó Production Licence. To the extent that the Group cannot fulfil the requirements, it might have to request extensions for filing a Plan or it may be at risk of losing rights under the Makó Production Licence. Alternatively, the Group may disagree with the government's interpretation of the legal requirements, in which case the Group may commence a legal proceeding, which could delay development of the Makó Production Licence. Failure to carry out any commitments within the currently required timeframes, or to successfully negotiate extensions to the time permitted to carry out these work plan commitments, could result in the Group losing those relevant interests and the associated resource potential therein and also restrict the ability to obtain new licences in the relevant jurisdictions. The Group's rights to exploit many of their oil and gas interests are limited in time. There is no guarantee or assurance that such rights can be extended or that new rights can be obtained to replace any rights that expire. Furthermore, as licence terms and commitments are typically set by governments, unexpected and significant changes to licence terms and commitments could significantly impact the value of those licences to the Group, which may have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group is exposed to general business risks associated with its joint venture and other partners, in addition to their ability to perform their contractual obligations.
Like other companies of its size, the development of the Group's business is substantially reliant on forming strategic relationships with other, larger companies in the oil and gas industry, such as it has with Hess (Australia), Chevron (South Africa) and NIS (Hungary). The Group has sought and is likely to continue to seek to involve both the financial resources and the technical expertise and experience of farm-out or joint venture partners to explore and develop some or all of its interests. However, these relationships involve surrendering certain economic and operational rights to such partners. As a result, the Company's return on assets operated by others depends upon a number of factors that may be outside of the Group's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

The Group will be exposed to the general risks associated with the businesses, operations and financial condition of its joint venture and other partners including, among other things, the risks of bankruptcy, insolvency, management changes, adverse change of control and natural disasters. There is also a risk that the Group may have disputes with these parties, including disputes regarding the quality and/or timelines of work performed by these parties. A failure by one or more of the Group's partners to satisfactorily meet on a timely basis the agreed-upon commitments may materially and adversely impact the Group's business,prospects, financial condition and results of operations.

The Group may have substantial capital requirements that, if not met, may hinder its growth and operations.
The Group's future growth depends on its and its partners' ability to make large capital expenditures for the exploration and development of oil and gas interests. Future cash flows and the availability of financing will be subject to a number of variables, such as:-

- the success of the Group's exploration and development programme in Australia, South Africa and Hungary;
- success in locating new resources; and
- prevailing prices of oil and gas.

Additional financing sources may be required in the future to fund developmental and exploratory drilling. Issuing equity securities to satisfy the Group's financial requirements could cause substantial dilution to its existing Shareholders. Financing might not be available in the future or the Group might not be able to obtain necessary financing on acceptable terms. If sufficient capital resources are not available, the Group might be forced to curtail its activities or be forced to sell some of its interests on an untimely or unfavourable basis, which would have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The success of the Company's acquisition strategy is not guaranteed.
Falcon's strategy is to leverage the Group's knowledge of and expertise in the unconventional oil and gas industry to acquire interests in licences covering large acreages of land, to build on its internationally diversified portfolio of unconventional interests. Returns ultimately achieved by investors in the Company will be reliant upon the quality and performance of the assets being acquired directly or indirectly by the Company. The success of the Company's strategy also depends on the Board's and management's ability to identify suitable assets, and their acquisition on favourable terms in order to generate value from those assets. No assurance is given that the strategy to be used will be successful under all or any market conditions or that the Company will be able to invest its capital directly or indirectly to acquire assets on attractive terms and to generate returns for investors. This could have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Company might not be able to identify liabilities associated with its licences which could cause the Group to incur losses.
Although the Company believes it has reviewed and evaluated its assets in Australia and Hungary in a manner consistent with industry practices, such review and evaluation might not necessarily reveal all existing or potential problems. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

Resource estimates depend on many assumptions that may be inconclusive, subject to varying interpretations, or inaccurate.
Although the Company believes that the CPR prepared by RPS Energy was in accordance with industry standards, the Company cannot be sure that that the actual results will be as estimated. The CPR represents RPS Energy's best professional judgement and should not be considered a guarantee or prediction of results.

Further drilling and production testing of horizontal wells will be necessary before the Group is able to make an estimate of recoverable volumes in any of its assets and it is possible that such further drilling and production testing may not yield positive results.

Drilling for and producing oil and gas are high-risk activities with many uncertainties that could adversely affect the Group's business, prospects, financial condition or results of operations.
The Group's future success depends primarily on the outcome of its exploration activities. These activities are subject to numerous risks beyond the Group's control, including the risk that it will not find any commercially productive oil or gas reservoirs. This is particularly true with respect to the exploration and development of oil and gas from unconventional reservoirs, such as shale gas, which relies on innovative and relatively expensive techniques and often involves exploration in areas where no proven reserves exist. The Group's decisions to purchase, explore, develop or otherwise exploit its interests will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or prevent drilling operations, including:-

- unexpected drilling conditions;
- pressure or irregularities in geological formations;
- equipment failures or accidents;
- pipeline and processing interruptions or unavailability;
- adverse weather conditions;
- lack of market demand for oil and gas;
- delays imposed by or resulting from compliance with environmental and other regulatory
- requirements;
- shortage of or delays in the availability of drilling rigs and the delivery of equipment; or
- reductions in oil and gas prices.

The Group's future drilling activities might not be successful, and drilling success rate overall or within a particular area could decline. The Group could incur losses by drilling unproductive wells. Shut-in wells, curtailed production and other production interruptions may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

Market conditions or operation impediments may hinder the Group's access to oil and gas markets or delay any production in the future.
The marketability of any future production from the Group's interests will depend in part upon the availability, proximity and capacity of pipelines, oil and gas gathering systems and processing facilities. This dependence is heightened where this infrastructure is less developed. The Group may also be required to shut-in wells, at least temporarily, for lack of a market or because of the inadequacy or unavailability of transportation facilities. If that were to occur, the Group would be unable to realise revenue from those wells until arrangements were made to deliver production to market. The Group's ability to produce and market oil and gas is affected and also may be harmed by:

- the lack of pipeline transmission facilities or carrying capacity;
- the proximity and capacity of processing equipment;
- the availability of open access transportation infrastructure;
- government regulation of oil and gas production including environmental protection, royalties,
- allowable production, pricing, importing and exporting of oil and gas;
- government transportation, tax and energy policies;
- changes in supply and demand for oil and gas; and
- general economic conditions.

Any change in such factors may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

Shortages of rigs, equipment, supplies and personnel could delay or otherwise adversely affect the Group's cost of operations or its ability to operate according to its business plans.
From time to time, shortages of drilling and completion rigs, field equipment and qualified personnel could occur, resulting in sharp increases in costs. The demand for wage rates of qualified drilling rig crews generally rise in response to the increased number of active rigs in service and could increase sharply in the event of a shortage. Shortages of drilling and completion rigs, field equipment or qualified personnel could delay, restrict or curtail the Group's exploration and development operations, which may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

The loss of the Group's key management, technical personnel and Directors or its inability to attract and retain experienced technical personnel could adversely affect the Group's ability to operate.

The Company depends to a large extent on the efforts and continued employment of the members of the Group's management team and certain board members. The loss of such services could adversely affect the Group's business operations. The success of the Group's operations depends on the Group's ability to attract and retain experienced petroleum engineers, geologists and other key personnel. From time to time, competition for experienced engineers and geologists is intense. If the Group cannot retain these personnel or attract additional experienced personnel, its ability to compete in the geographic regions in which the Group conducts operations could be harmed and as a result it may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

The Group 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.

Exploration for and exploitation, production and sale of oil and gas in Australia, South Africa and Hungary are subject to extensive national and local laws and regulations, including complex tax laws and environmental laws and regulations, and requires various permits and approvals from various governmental agencies. If these permits are not issued or unfavourable restrictions or conditions are imposed on the Group, it might not be able to conduct its operations as planned, or at all. Alternatively, failure to comply with these laws and regulations, including the requirements of any permits, might result in the suspension or termination of operations and subject the Group to penalties. Compliance costs may be significant. Further, these laws and regulations could change in ways that substantially increase the Group's costs and associated liabilities. The Group cannot be certain that existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations will not materially and adversely impact the Group's business, prospects, financial condition and results of operations.

The Company does not insure against all potential operating risks. It might incur substantial losses and be subject to substantial liability claims of its oil and gas operations.

The Company does not insure against all risks. It maintains insurance against various losses and liabilities arising from operations in accordance with customary industry practices and in amounts that Board believes to be prudent. Losses and liabilities arising from uninsured and underinsured events or in amounts in excess of existing insurance coverage could have a material adverse effect on the Group's business, prospects financial condition or results of operations. The Group's oil and gas exploration and production activities will be subject to hazards and risks associated with drilling for, producing and transporting oil and gas, and any of these risks can cause substantial losses resulting from:-

- environmental hazards, such as uncontrollable flows of oil, gas, brine, well fluids, toxic gas or other
- pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- fires and explosions;
- personal injuries and death;
- regulatory investigations and penalties; and
- natural disasters.

Any of these risks could have a material adverse effect on the Group's ability to conduct operations or result in substantial losses. The Company might elect not to obtain insurance if it believes that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, this may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

2. RISKS RELATING TO THE GROUP'S INDUSTRY

Competition in the oil and gas industry is intense, and many of the Group's competitors have greater financial, technological and other resources than the Group does, which may adversely affect its ability to compete.

The Group operates in the highly competitive areas of oil and gas exploration, development and acquisition with a number of other companies doing business in Australia, South Africa and Hungary. The Group faces intense competition from both major and other independent oil and gas companies in the locations where the Group operates. Many of the Group's competitors have substantially greater financial, managerial, technological and other resources. These companies might be able to pay more for exploratory prospects than the Group's financial resources permit. To the extent competitors are able to pay more for assets than the Group is willing to pay, it will be at a competitive disadvantage. Further, many competitors may enjoy technological advantages and may be able to implement new technologies more rapidly. The Group's ability to explore for oil and gas prospects and to acquire additional assets in the future will depend upon its ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable assets and consummate transactions in this highly competitive environment. This may have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

The Group has been an early entrant into new or emerging shale plays. As a result, its expectations regarding future drilling results in these areas are uncertain, and the value of its undeveloped acreage will decline if future drilling results are unsuccessful.

The Group has been an early entrant into new or emerging shale plays in the areas in which it operates, particularly in Australia and South Africa. Although the Group believes that its early entry has provided it with certain competitive advantages, including having had a wider selection of available concessions to choose from, there is no guarantee that such competitive advantages can be maintained in the future as more competitors, many of whom are larger than the Group in size and operation, enter into these regions. Additionally, the Group's prospects and expectations regarding future drilling results in these emerging shale plays are more uncertain than they would be in areas that are developed and producing substantial quantities of oil or gas already. Since new or emerging shale plays have limited or no production history, the Group is unable to use past drilling results in those areas to help predict its future drilling results. As a result, the Group's risk on the costs of drilling, completing and operating wells in these areas may be higher and the value of the Group's undeveloped acreage will decline if future drilling results are unsuccessful, all of which may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

The environmental implications of certain technologies used in shale gas exploration activities are under scrutiny.

The Group's activities involve exploring for shale gas utilising drilling and completion techniques, such as horizontal drilling and hydraulic fracturing, the environmental implications of which have been, and continue to be, subject to significant controversy and public debate. Given that these technologies are relatively new, their environmental implications may not be fully understood at present, and research into their effects is still ongoing. There has been speculation about, amongst other things, the possible effects of hydraulic fracturing on water aquifers (due to either the chemicals used in fraccing fluids or gases released from the shales), contribution to seismic activity and disruption to local ecosystems. The controversy surrounding the environmental implications of shale gas exploration has led to opposition from significant sections of the public as well as certain legislative and regulatory initiatives aimed at restricting these activities. Further to the South African moratorium on shale gas exploration as announced in February 2011, similar initiatives have been introduced in a number of European countries (Bulgaria, France, Romania and the UK) and also in various regions of Canada and the United States. Any further restrictions on these activities in South Africa, or the introduction of such restrictions in any of the locations in which the Group operates (including a prohibition on hydraulic fracture stimulation), which make shale gas exploration and production currently unviable due to a lack of presently-existing alternative technologies, could prevent the Group from being able to profitably develop its interests.

Furthermore, if any of the Group's activities were found to have caused environmental damage in any of the locations in which it operates, it could be subject to significant liabilities and reputational damage. Even if no environmental damage were tied directly to the Group's activities, to the extent operations by other companies in the shale gas industry were found to have caused environmental damage or to the extent further research provides evidence of negative environmental implications of fraccing or other aspects of shale gas exploration, public and political opposition to shale gas exploration may be further intensified and the Group's business could come under increasing legal and regulatory restrictions, all of which may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

A substantial or extended decline in oil and gas prices may adversely impact the Group's business, prospects, financial condition and results of operations.

The Group's future revenues, operating results and rate of growth are substantially dependent upon the prevailing prices of, and demand for, oil and gas. Declines in the prices of, or demand for, oil and gas may adversely affect the Group's business, prospects, financial condition and results of operations. Lower oil and gas prices may also reduce the amount of oil and gas that the Group can produce economically. Historically, oil and gas prices and markets have been volatile and they are likely to continue to be volatile in the future. Oil and gas prices are subject to wide fluctuations in response to relatively minor changes in the supply of, and demand for, oil and gas, market uncertainty and a variety of additional factors that are beyond the Group's control. Among the factors that could cause this fluctuation are:-

- change in global supply and demand for oil and gas;
- levels of production and other activities of the OPEC, and other oil and gas producing nations;
- weather conditions;
- the availability of transportation infrastructure;
- market expectations about future prices;
- the level of global oil and gas exploration,
- production activity and inventories; the overall level of energy demand;
- the effect of worldwide environmental and/or energy conservation measures;
- currency exchange rates;
- government regulations and taxes;

- the overall economic environment;
- political conditions, including embargoes, in or affecting other oil producing activity; and
- the price and availability of alternative fuels.

A substantial or extended decline in oil or gas prices may materially and adversely impact the Group's business, prospects, financial condition and results of operations.

Political instability or fundamental changes in the leadership or in the structure of the governments in the jurisdictions in which the Group operates could have a material negative impact on the Group's business, prospects, financial condition and results of operations.
The Group's interests may be affected by political and economic upheavals. Although the Group currently operates in jurisdictions that welcome foreign investment and are generally stable, there is no assurance that the current economic and political situation in these jurisdictions will not change significantly in the future.

Local, regional and world events could result in changes to the oil and gas, mining, tax or foreign investment laws, or revisions to government policies in a manner that renders the Group's current and future interests uneconomic could have a material adverse affect on the Group's business, prospects, financial condition and results of operations. Furthermore, there is also the risk of resource nationalisation, or the imposition of restrictions and penalties on foreign-owned entities which may materially impact the Group's business, prospects, financial condition and results of operations.

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.

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INDUSTRY OVERVIEW - and impact on the company in jurisdictions in which it operates

The information in the following section has been provided to augment existing disclosures within the document in response OSC Staff Notice 51-720 "Issuer Guide for Companies Operating in Emerging Markets". The information has been extracted from a variety of sources released by public and private organisations. The primary sources for information in this section are the Australian Government Bureau of Resources and Energy Economics "Energy in Australia" report (2012), "Energy White Paper 2011" published by the Commonwealth of Australia, PwC analysis of South African gas industry (June 2012), International Energy Agency ("IEA") report on Hungary (2012), KPMG Central and Eastern European Shale Gas Outlook, American Association of Petroleum Geologists European Region Newsletter (June 2012) the Hungarian Energy Office Annual report to the European Commission (August 2011) and the European Bank for Reconstruction and Development Profile on Hungary.

1. INTRODUCTION TO SHALE GAS

(a) Shale Gas versus Conventional Gas

Natural gas resources are typically divided into two categories: conventional and unconventional. Conventional gas typically is found in reservoirs with permeabilities greater than 1 mD and can be extracted via traditional techniques. A large proportion of the gas produced globally to date is conventional, and is relatively easy and inexpensive to extract. In contrast, unconventional gas is found in reservoirs with relatively low permeabilities (less than 1 mD) and hence cannot be extracted via conventional methods. There are several types of unconventional gas resources that are produced today but the three most common types are tight gas, coal bed methane and shale gas. Given the low permeability of these reservoirs, the gas must be developed via special techniques including hydraulic fracture stimulation, or fraccing, in order to be produced commercially.

(b) The Rise of Shale Gas in the US

Shale gas technology has been largely pioneered in the US and the emergence of US shale gas plays has fundamentally altered the US natural gas supply picture. The first shale gas well in the US commenced production in 1821 from a well near Fredonia, New York. Low level shale gas production occurred between this period and the year 2000, however the shale gas industry in the US started to gain significant momentum from 2006. The US domestic gas price has declined dramatically in recent years due to the excess of supply over demand. Since early 2009, prices for natural gas and crude oil have decoupled due to the increase in production of gas from domestic shales but at the same time, the shale gas and shale oil segment of the US oil and gas industry has continued to attract significant investor interest from both trade and financial investors.

(c) Key Shale Gas Production Techniques

Shales typically have low permeability. As a result of this, many wells are required to deplete the reservoir and special well design and well stimulation techniques are required to deliver production rates of sufficient levels to make a development economic. Horizontal drilling and hydraulic fracture stimulation have both been crucial in the development of the shale gas industry.

Horizontal Drilling

Horizontal drilling is a technique which allows the wellbore to come into contact with significantly larger areas of hydrocarbon bearing rock than a vertical well. As a result of this increased contact, production rates and recovery factors can be increased. As the technology for horizontal drilling and fraccing has improved, the use of horizontal drilling has increased significantly.

Hydraulic Fracture Stimulation

Hydraulic fracture stimulation, or fraccing, is a process through which a large number of fractures are created hydraulically in the rock through the application of high pressure, thus allowing the natural gas and/or crude oil trapped in subsurface formations to move through those fractures to the wellbore from where it can then flow to the surface. Fraccing can both increase production rates and increase the total amount of gas that can be recovered from a given volume of shale. Pump pressure causes the rock to fracture, and water carries sand into the hydraulic fracture to prop it open allowing the flow of gas. Whilst water and sand are the main components of hydraulic fracture fluid, chemical additives are often added in small concentrations to improve fracturing performance.

(d) Benefits of Technology Improvements

Decline in Drilling Costs

Due to the extensive reliance on horizontal drilling and hydraulic fracturing, the costs associated with the development of shale resources can be significantly higher than for conventional oil and gas. However, these costs have reduced over the past decade in North America due to efficiency improvements resulting from large scale drilling programmes.

Decline Mitigation and Increased Recovery
A combination of improved technology and shale-specific experience has also led to improvements in recovery factors and reductions in decline rates. Each shale play requires its own specific completion techniques, which can be determined through careful analysis of rock properties and trial and error of the drilling and completion parameters. The correct selection of well orientation, stimulation equipment, fracture size and fraccing fluids can all affect the final performance of a well. For developed shales in North America the combined benefits of improved technology and increased experience have resulted in the upward shift of well type-curves (expected well production curves) over time. Both the expected ultimate recovery per well and the peak production per well have been seen to increase as plays have matured.

(e) Environmental Considerations
Water Usage and Recycling
A large volume of water is needed for the development of shale gas plays. Water is used for drilling, where it is mixed with clays to form drilling mud. This mud is used to cool and lubricate the drill-bit, provide well-bore stability and also carry rock cuttings to the surface. Water is also used in significant volumes in fraccing. In addition to water and sand, a small concentration of other additives is combined with fluid to improve fraccing efficiency. This significant volume of water needs a plentiful source.

A typical fraccing fluid is more than 98% water and sand. The other 2% is made up of a number of additives which may vary depending on the particular well and operator. Typically additives include many substances that are commonly found in small measure in various household products. During a typical hydraulic fracturing process the frac fluid is transmitted down cased well-bores through perforations to the target zones and then forced deep into the targeted shale gas formations. In some quarters, there is a concern that the fraccing fluid may contaminate drinking water in the area. In order to minimise the risk of any groundwater contamination, good drilling practice requires that one or more strings of steel casing are inserted into the well and cemented into place so as to ensure that the entire well-bore, other than the production zone, is completely isolated from the surrounding formations including aquifers. Most oil-bearing or gas-bearing shales tend to be at least 1,500 metres below the surface, whereas aquifers are generally no more than 500 metres below the surface. Given (i) the thickness of rock separating target shale formations from overlying aquifers, and (ii) the extremely low permeability of shale formations themselves, and assuming the implementation of good oilfield completion practices (such as casing and cementing), it is considered by the industry that, while it cannot be excluded altogether, the risk of contamination of overlying aquifers as a result of fraccing operations is remote. Instances where contamination of aquifers has been alleged are generally believed to have involved poor drilling practices, in particular poor casing and cementing of a well or poor construction of surface storage facilities. Technology improvements have led to significant enhancements in the environmental performance of fraccing fluids and there are a number of products on the market which offer advancement in this area including, for example, a fraccing fluid developed by Halliburton using products from the food industry. In addition, companies are exploring technology which will facilitate the recycling of water used in the fraccing process.

Although the recycled water cannot yet be filtered enough for drinking or for agricultural use, it aims to allow companies to reuse this water in other wells and thus equate to significant savings over the lifetime of a typical well.

Disturbance
The disturbance of the land surrounding the drilling location is another environmental factor that may be considered. While the space required for a shale well location is frequently larger than that required for equivalent conventional plays multiple wells may be drilled from a single location.

2. AUSTRALIA

(a) Overview
Australia is the world's ninth largest energy producer, accounting for around 2.5% of world energy production and 5% of world energy exports. In 2011, Australia was the third-largest energy producer in the world and one of only three OECD net energy exporting countries. Exports accounted for around 80% of Australia's total energy production (in energy content terms) in 2010/2011. Fossil fuels accounted for around 96% of Australia's primary energy consumption and 90% of electricity generation in 2010/2011. With around A$290 billion of energy resource projects in planning or under development, Australia is well placed to supply its domestic energy needs and service global energy markets over the coming decade.

(b) Oil and Gas Production
Australia has diverse energy sources and has approximately 33% of the world's uranium resources, approximately 10% of world black coal resources, and approximately 2% of world conventional gas resources. Australia has a relatively small proportion of world resources of crude oil and is a net importer of oil. At current rates of production, Australia's energy resources are expected to last for several decades.

Australia's primary energy production is dominated by coal which, in 2009/2010, accounted for approximately 61% of total energy production, followed by uranium (approximately 19%) and gas (approximately 12 %). Crude oil and LPG combined represented approximately 6% of total energy production, and renewables approximately 2%. Gas (conventional and unconventional) is becoming increasingly important for Australia, both as a domestic energy source and as a source of export income. Australia is a significant exporter of LNG, with around half of all gas production exported. In 2010/2011, the value of Australian LNG exports was A$10.4 billion. Since 1999/2000, domestic gas consumption has increased at an average annual rate of 4%. Gas accounted for 23% of Australian energy consumption, and 15% of electricity generation in 2009/2010.

Australia's conventional gas production is almost entirely sourced from three basins, with the Carnarvon (north-west Western Australia), Cooper/Eromanga (central Australia) and Gippsland (Victoria) basins accounting for 98% of production in 2010/2011. The Northern Territory is the smallest gas market in Australia, with supply historically sourced from the onshore Amadeus Basin. Gas production in the Northern Territory totalled 19 Bcf (20 Petajoules) in 2010/2011. Until 2005/2006, all of the gas produced in the Northern Territory gas market was consumed locally. The development of the offshore Bayu Undan field in 2005/2006 saw Darwin selected as the site for Australia's second LNG facility. In 2009, the offshore Blacktip gas field in the Bonaparte Basin started production with gas being piped onshore to supplement the declining Amadeus Basin supply. A second LNG plant for Darwin to process gas from the Ichthys field was announced by Inpex and Total (equity owners of Ichthys) in January 2012.

(c) Gas Infrastructure

The geographical distance between population centres in Australia as well as its key export markets limits trade by conventional pipeline transport. Instead, cooling the gas to –161ºC allows the volume to be reduced to enable it to be shipped as LNG. Australia's annual LNG export capacity at the end of 2011 was 974 Bcf (20 million tonnes), more than three quarters of this is located in Western Australia with the remainder in the Northern Territory near Darwin. Production of LNG is exported, with the major trading partners being Japan, China and the Republic of Korea. There are seven additional LNG projects either under construction or at an advanced stage of development.

The Northern Territory represents a sixth of the Australian land mass and has a population of approximately 232,000 people. For a sparsely populated and remote jurisdiction it is well-served with infrastructure. Darwin, the capital city of the Northern Territory, has a deep water port which is connected to the Darwin to Adelaide railway line. Taking advantage of its location and capacity, there is a number of major projects currently being developed for the Darwin area, including:-

- A$34 billion Ichthys LNG project on Blaydin Point.
- A$110 million Marine Supply Base at East Arm Wharf, which will service oil and gas ships
- such as rig tenders.
- A$55 million Darwin Industry Fuel Terminal – a common user facility adjacent to the East Arm
- Wharf that provides tank storage and related logistics for the oil and chemical industries.
- A$50 million Helium Plant – the plant exports two thirds of its production to South-East Asia.

(d) Unconventional Oil and Gas in Australia

In recent years increasing attention has been given to the potential of unconventional oil and gas in Australia. This interest extends to the Northern Territory with a large portion of available land either covered by exploration permits or under application. A coal seam gas industry has developed rapidly over the last ten years. The industry is primarily based in Queensland and is intended to provide feedstock to three LNG plants currently under construction there.

Exploration for tight shale oil and gas is currently being undertaken across Australia over large areas in Western Australia, South Australia and the Northern Territory. Major oil companies have invested in exploration in the Northern Territory including Hess Corporation in Falcon's Beetaloo project, Statoil in PetroFrontier's Southern Georgina Basin permits and Santos in Tamboran's McArthur Basin play. Technical support is not as advanced as in the United States but with increasing exploration and potential production, capacity is increasing and appropriate equipment and skilled personnel are becoming more readily available.

The Northern Territory Geological Survey has developed initial estimates that there is potentially 200 Tcf of unconventional gas in the Northern Territory. On 21 September 2012, the Minister for Mines and Energy, the Hon Willem Westra van Holthe MLA, announced that "the Country Liberals Government supports the development of the unconventional shale oil and gas industry in the Territory".

While exploration is generally at the first stage, the first Australian commercial unconventional gas was produced by Santos in South Australia's Cooper Basin in October 2012.

(e) Regulation and Pricing
Government policies play an important role in shaping the energy market, and can affect both the pace of energy demand growth and the type of energy used.

Oil and gas exploration in the Northern Territory is regulated by the Northern Territory Government through the Petroleum Act (NT). The legislation is administered by the NT Department of Mines and Energy. Exploration permits and production licences are issued and controlled by the department. The Northern Territory Government is currently reviewing the legislation regulating the industry to ensure that it reflects current technological capability, industry best practice and the needs of the community. The Australian domestic gas market consists of three distinct regional markets: the eastern market (Australian Capital Territory, New South Wales, Victoria, Queensland, South Australia and Tasmania); the western market (Western Australia); and the northern market (Northern Territory). The geographical isolation of these markets makes interconnection costly and currently uneconomic. Until recently, and with the exception of Victoria, wholesale gas was sold under confidential long term contracts between producers, pipeline operators, major users and retailers. The Victorian Wholesale Gas Market was established in 1999 to increase the flexibility of market participants in buying and selling gas. In September 2010, the Sydney and Adelaide hubs of the Short Term Trading Market (“STTM”) commenced operation. The STTM is a day-ahead wholesale spot market for gas that aims to increase price transparency and improve efficiency and competition within the gas sector. LNG contract prices are generally indexed to world oil prices, with higher world oil prices leading to higher LNG contract prices.

(f) Fiscal Conditions
Companies are subject to Commonwealth taxes including the Goods and Services Tax (“GST”) of 10% From 1 July 2012 the Commonwealth Government’s Petroleum Resource Rent Tax (“PRRT”) has been extended to onshore petroleum projects and is currently levied at the rate of 40% on the taxable profits derived from the petroleum project in a year of tax. A year of tax is the first financial year in which assessable petroleum receipts are derived by a taxpayer and any subsequent financial year. During exploration the Northern Territory Government has an annual fee for the permits. There is a royalty of 10% on all production. Commonwealth Government corporation tax is set at 30%.

3. SOUTH AFRICA

(a) Overview
South Africa is Africa’s biggest economy with an estimated GDP of $524 billion. The main contributor to GDP is the services sector at approximately 67%, followed by industry at approximately 31% with agriculture making up just 3%. Of the country’s 50 million people, an estimated 25% are unemployed resulting from modest economic growth, which has averaged approximately 3% per annum since 1995. The 2009/2010 figures from the South African Department of Energy confirm that South Africa’s primary energy source is coal. Coal constitutes approximately 66% of the energy supply followed by crude oil at approximately 22%, renewables and waste at approximately 8% and gas at approximately 3% While coal is largely used to generate electricity, a significant amount is channeled to synthetic fuel and petrochemical operations. Sasol, an integrated energy and chemical company, is the largest coal-to-chemicals producer in the world and beneficiates coal, oil and gas into liquid fuels, fuel components and chemicals with the help of its proprietary Fischer-Tropsch processes. Because of its dependence on coal, South Africa is the 14th highest emitter of greenhouse gases.

Natural gas accounts for a small portion of the energy mix in South Africa (3%) but this is expected to grow to around 10% over the next decade. The South African Government has stated its objective to reduce emission levels and to increase the use of natural gas as a substitute for coal is seen as one way of achieving this. The availability of natural gas in neighbouring countries, such as Mozambique and Namibia, and the discovery of offshore gas reserves in South Africa are expected to change the gas industry in South Africa.

(b) Oil and Gas Production
The history of South Africa’s oil industry dates to 1884, when the first oil company was established in Cape Town to import refined products. The first organised search for hydrocarbons was undertaken by the Geological Survey of South Africa during the 1940s. In 1965, Soekor (Pty) Ltd was established by government with the strategic imperative of finding domestic oil and gas. Oil exploration has been conducted primarily offshore. The Bredasdorp Basin, which contains South Africa’s only oil and gas production facilities, has been the focus area for oil and gas exploration in South Africa. By comparison with more developed oil and gas regions, South Africa is relatively underexplored. Since 1965 approximately 300 wells have been drilled with approximately 233,000 kilometres of 2D seismic data and 10,200 km2 of 3D seismic data being acquired.

South Africa has four conventional refineries and three synfuel plants with a total refining capacity of approximately 700 Mbopd. Of the refined product, 513 Mbopd is produced from crude oil, 150 Mbopd from coal to liquids and 45 Mbopd from gas to liquids.

(c) Gas Infrastructure
The South African energy landscape is dominated by coal and South Africa does not have any significant proven reserves of indigenous natural gas or production. According to Business Monitor International, South Africa had proven natural gas reserves of 0.7 Tcf in 2011. Current demand for natural gas in South Africa is mainly for the gas to liquids and chemicals industries, where PetroSA, Sasol and some industrial users are the major players.

(d) Unconventional Oil and Gas in South Africa
The Karoo Basin extending to approximately 173 million acres (approximately 700,000 km2) in size located in central and southern South Africa and contains thick, organic rich shales. Until recently, the Karoo Basin was not considered prospective for commercial hydrocarbons resulting in very limited modern hydrocarbon exploration onshore in South Africa. In an independent report dated April 2011, the U.S. Energy Information Administration ("EIA") estimated that there are 485 Tcf technically recoverable resources in the Karoo Basin which would rank it fifth in the world after China, USA, Argentina and Mexico for shale gas potential.

On 1 February 2011, a moratorium on shale gas exploration in South Africa was put in place and from 29 April 2011 all permit applications were suspended whilst the South African Department of Mineral Resources conducted, *inter alia*, an environmental study on the effects of hydraulic stimulation. In September 2012, the South African Government announced that the moratorium on shale gas exploration in South Africa would be lifted which should increase activities in the region.

(e) Regulation and Pricing
South Africa has a network of key laws and regulations which provides the general legal framework for oil activities. The Constitution of the Republic of South Africa requires the government of South Africa to implement legislative measures to ensure the ecologically sustainable development and use of South Africa's natural resources. In 2002, the Mineral and Petroleum Resources Development Act 28 of 2002 (the "MPRDA") repealed the 1991 Minerals Act to give legislative effect to the constitutional imperatives. The MPRDA declares petroleum resources (which include oil) the common heritage of the people of South Africa and the state the custodian thereof. Petroleum Agency SA (Pasa) is the official agency responsible for the promotion and regulation of South Africa's petroleum resources. The agency regulates and monitors exploration and production activities and is the custodian of the South African exploration and production database for petroleum.

South Africa is dependent on imported crude oil and is accordingly exposed to increased input prices. Upward increases in international crude oil prices partly account for escalation in domestic inflation, with the impact of this depending on the strength of the South Africa Rand. The price-setting regime for crude oil products is mandated by the Petroleum Products Act and maximum retail prices are set out in the regulations thereto.

(f) Fiscal Conditions
The South African Government is entitled to a royalty on the sale of mineral resources of up to 7% of gross sales (in the case of unrefined resources) and 5% of gross sales (in the case of refined resources, such as oil and gas).

The Liquid Fuels Charter provides that an oil and gas company must reserve not less than 8% for Historically Disadvantaged South Africans ("HDSA") to buy-in to any offshore production right granted. The HDSA buy-in is also expected to apply to onshore production rights in South Africa. Similarly, the State has an option to acquire an interest of up to 10% in any production right granted. However, it is not required to pay any consideration for its 10% interest or contribute to past costs, but must contribute *pro rata* in accordance with its interest towards production costs going forward. Corporation tax in South Africa is imposed at a rate of 28% of taxable income. Dividends tax is imposed on the shareholder at a rate of 15%.

4. HUNGARY

(a) Overview
Hungary has been a petroleum producer since the early 20th century. The Pannonian Basin covers most of Hungary and marine to lacustrine sediments deposited in this basin during the Miocene period are believed to be the source for most of Hungary's hydrocarbons. Hungary relies on natural gas for the largest portion of its total primary energy supply ("TPES"), accounting for 39% of the total supply in 2010. Renewable energies have grown progressively, but they nevertheless remain limited in TPES share, at 8% in 2010. In 2009, the parliament gave its preliminary permission to begin preparations for the setup of new nuclear units at the site of the existing Paks nuclear power plant.

(b) Oil and Gas Production
Hungary has oil reserves, primarily in the south-east of the country. Domestic crude oil production peaked in 1985, at 64 Mbopd and is in decline. In 2010 domestic production, including crude oil and condensate, amounted to 25 Mbopd, or 13 % of total oil supply. In 2010, Hungary's oil demand was 147 Mbopd. Approximately 87% of Hungary's crude oil supply in

2010 was imported, with most of this coming from Russia via the Druzhba pipeline system. Because of the declining domestic production, import dependency is expected to grow further.

Hungary is also highly dependent on imported natural gas which in 2010 amounted to approximately 336 Bcf. Domestic gas production had been relatively stable from 2007, at around 88-92 Bcf. The country has proven gas reserves of 3 Tcf, according to Cedigaz, providing 38 years of supply at 2010 production levels. Gas production comes mostly from mature fields, and the government believes that production can be maintained at close to these volumes until around 2020. Thereafter, production is expected to decline considerably if no new resources are developed. The main consumers of natural gas are the residential sector (approximately 35%), power generation (approximately 30%), and the commercial sector (approximately 17%).

(c) Gas Infrastructure

Hungary's gas transmission network consists of some 5,632 kilometres of high-pressure pipelines, with 402 gas delivery points. The network includes five compressor stations with a total installed capacity of 135 mega watts. Hungary imports most of its gas from Russia via Ukraine at Beregdaróc (2 Mmcfpd), but also small amounts via Austria at Mosonmagyaróvár (427 Mcfpd). Hungary is planning to enhance its import capacity as well as diversifying import routes and sources. The planned Nabucco Gas Pipeline is expected to provide access to the gas resources of the Caspian and the Middle East. Hungary is also a key transit country for Russian gas to south-east Europe, and is looking at expanding its general role as a transit country. The gas transmission system is owned and operated by Földgázszállító Zrt ("FGSZ"), part of MOL Group.

(d) Unconventional Oil and Gas in Hungary

According to the US Energy Information Administration, the joint technically recoverable shale gas resources for Romania, Bulgaria and Hungary is around 19 Tcf. The government is encouraging unconventional gas production with lower royalty rates (12%) than conventional gas production (up to 30%).

One of the more promising exploration areas is considered to be the Makó Trough, which is located in the southern part of Hungary. The licences of the mining properties of the Makó Trough belong to MOL Group and the Company. The Company and NIS have agreed a three-well drilling program beginning in 2013 targeting gas in the Makó Trough. MOL is exploring the Derecske basin. There are a number of other companies involved in shale gas exploration in Hungary, such as RAG Hungary Kft. and Cuadrilla Resources Ltd, which are actively seeking reserves in various parts of the country. WildHorse Energy has been working on an underground coal gasification ("UCG") pilot using their CBM exploration licence in the Mecsek Hills, in southern Hungary. Near the borders of Hungary, several other unconventional operations have been taking place. Ascent Resources, a UK company, announced that it had discovered 413 Bcf of unconventional gas near the Slovenian-Hungarian border. INA/MOL's pilot in the Drava trough in Croatia and NIS's Majdan project in northern Serbia all target Lower to Upper Miocene high TOC shales and adjoining tight sediments.

(e) Regulation and Pricing

The Hungarian Ministry of Transportation, Telecommunication and Energy (the "Ministry") is charged with primary responsibility for the energy sector and regulatory implementation is the responsibility of the Hungarian Energy Office ("HEO"). The HEO is a legally autonomous body regulating electricity, gas and district heating, under the supervision of the Ministry. While the HEO does not have the power to set either tariff rates or methodologies, the regulator plays an important role in pricing through the imposition of performance standards and through its licensing regime and through the issuance of guidelines to calculate electricity grid charges, wielding important authority in the implementation of the tariff regime within the final pricing issued by the Ministry. The HEO issues licences (for generation/production, transmission, distribution and supply/trade) and authorisations for new generation capacity.

Hungary is highly dependent on Russian natural gas, with imports from Russia covering nearly 80% of domestic consumption. Hungary's 20-year contract with the largest gas importer, Panrusgáz, a Gazprom subsidiary, is set to expire in the coming years, and will be subject to renegotiation in 2015. Russian gas is based on a "take or pay" contract indexed to oil prices. This is expected to be slowly replaced by spot gas prices in the long run due to the increased differential between Russian indexed and European natural gas spot prices. The specific costs of natural gas is based on the price set in the long term purchase agreements indexed to petroleum products; the future market prices on the Endex TTF Gas (Dutch Gas Exchange) and the prices at the Central European Gas Hub, Vienna ("CEGH"). The so called 'mixed' specific natural gas prices consist of long term import contract prices with a weight of 60%, and the natural gas price established on the markets referred to above with a weight factor of 40%. Average spot prices for gas on the CEGH over the last three months equate to approximately $8.48 per Mcf[(1)]. Mining and Exploration & Production activities are governed by the Act No. XLVIII on mining. The regulatory body of mining activities is the Hungarian Office for Mining and Geology.

(f) Fiscal Conditions
The fiscal regime in Hungary is tax and royalty based. There is a special royalty rate for the production of unconventional gas reserves. The exploration of non-renewable natural resources is subject to royalty, which varies, depending on the type of natural resource and the quantity exploited, between 0% and 30%. If the natural gas is coming from unconventional sources and extractable by special procedures such as fracturing, the royalty rate is fixed at 12%. The corporate income tax rate is 10% on taxable income up to HUF 500 million (approximately $2.5 million), and 19% on the remaining portion of the taxable income.

In 2009, an additional profit based energy industry tax, levied on energy supplying companies, was introduced. The rate was originally set at 8% but, as part of Hungary's third package of austerity measures, the rate has increased to 31% from 2013, with deductions allowable for certain capital expenditures.

[1]. Prices on the CEGH Gas Exchange are quoted in Euro per megawatt hour. Price shown equates to 3 month average spot price as at 22 February 2013, assuming an average heating value of 850 megajoules per Mcf, which equates to 0.24 megawatts per hour. Exchange rate used is average 3 month €/$ rate as at 22 February 2013 being $1.32.

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SUMMARY OF QUARTERLY RESULTS

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

(In thousands of $ unless otherwise stated)

As of:	**31 March 2012**	**30 June 2012**	**30 September 2012**	**31 December 2012**
Total assets	90,096	87,711	85,513	86,013
Exploration and evaluation assets	70,690	71,683	72,209	74,019
Working capital	11,321	688	(3,559)	(6,945)
Total shareholders' equity	60,590	55,701	47,665	46,913

For the three months ended:	**31 March 2012**	**30 June 2012**	**30 September 2012**	**31 December 2012**
Revenue	6	5	1	9
Net loss	(1,851)	(5,872)	(8,918)	(1,074)
Net loss attributable to common shareholders	(1,760)	(5,802)	(8,891)	(988)
Net loss per share-basic and diluted	(0.005)	(0.008)	(0.013)	(0.0014)

As of:	**31 March 2011**	**30 June 2011**	**30 September 2011**	**31 December 2011**
Total assets	114,227	126,256	124,287	94,901
Exploration and evaluation assets	99,755	82,665	91,437	70,977
Working capital	2,260	33,167	21,519	13,983
Total shareholders' equity	84,355	90,700	90,592	61,822

For the three months ended:	**31 March 2011**	**30 June 2011**	**30 September 2011**	**31 December 2011**
Revenue	8	9	7	9
Net loss	(2,958)	(1,749)	(759)	(29,361)
Net loss attributable to common shareholders	(2,900)	(1,708)	(645)	(29,308)
Net loss per share-basic and diluted	(0.005)	(0.002)	(0.001)	(0.044)

The Company is a development stage company, and has limited revenue which is not material.

The Company's net loss and net loss per share relate to the Company's operations during a particular period, and are not seasonal in nature.

As at 31 December 2011, the Company determined that the carrying value of the Hungarian exploration and evaluation assets and the Canadian natural gas interests exceeded their estimated fair value. Consequently, in 2011, the Company reflected an impairment of Hungarian exploration and evaluation assets of $26 million and an impairment of the Canadian natural gas properties of $35,000. No similar charge has been reflected in the current year financial statements as the Company has determined that there are no indicators of impairment present in accordance with IFRS 6 "Exploration for and evaluation of mineral interests".

Generally, the Company's total assets, exploration and evaluation costs, working capital and total shareholders' equity fluctuate in proportion to one another until such time as the Company completes additional financing.

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LIQUIDITY AND CAPITAL RESOURCES

Going Concern

For the year ended 31 December 2012, the Company incurred a net loss of $17.7 million and operating cash outflows of $9.3 million and as at 31 December 2012, had a retained deficit of $334.3 million.

On 14 March 2013 the Group announced its application for admission to trading on the AIM market of the London Stock Exchange (symbol: FOG) and the ESM market of the Irish Stock Exchange (symbol: FAC) of the Company's existing share capital and the additional 120,381,973 new common shares in the capital of Falcon to be issued pursuant to the concurrent conditional brokered private placement of new common shares at a price of Stg14 pence (CDN$0.215) per share to raise gross proceeds of $25 million (£16.9 million). Dealings in these shares commenced on AIM and ESM on 28 March 2013.

Having given due consideration to the cash requirements of the Group and having raised capital in the gross amount of $25 million, the Board has a reasonable expectation that the Group will have adequate resources to continue in operational existence for the foreseeable future. For this reason, the Board continues to adopt the going concern basis in preparing this financial information.

In the longer term, the recoverability of the carrying value of the Company's long-lived assets and interests in Australia, Hungary and South Africa is dependent upon the Company's ability to preserve its interest in the underlying petroleum and natural gas properties, the discovery of economically recoverable reserves, the achievement of profitable operations, and the ability of the Company to obtain financing to support its acquisition, exploration, development and production activities.

Working Capital

Cash and cash equivalents as at 31 December 2012 were $2.9 million, a decrease of $12.5 million from $15.4 million as at 31 December 2011. Working capital as at 31 December 2012 decreased to ($6.9 million) from $14 million as at 31 December 2011.

The decrease to cash and cash equivalents was attributable to cash used in operating and investing activities of $9.3 million and $3.5 million, respectively.

Restricted cash amounts to $0.4 million at 31 December 2012.

Accounts Receivable

Current accounts receivable as at 31 December 2012 were $1.8 million, which includes $0.4 million receivable from the Hungarian, Australian and Canadian governments as refunds of VAT and GST, respectively, $1 million due from Chevron (received in 2013) and other of $0.3 million.

Accounts Payables and Accrued Expenses

Accounts payable and accrued expenses as at 31 December 2012 were $3.1 million, and includes $2.1 million for accrued expenditure and restructuring provisions, as compared to accounts payable and accrued expenses expenditures related to the Shenandoah–1 well testing and other Beetaloo Basin activities in Australia of $2.3 million as at 31 December 2011.

Capital Expenditures

For the year ended 31 December 2012, capitalised additions to exploration and evaluation assets were $1.6 million of which $1.6 million was in Australia. For the year ended 31 December 2011, capitalised additions to exploration and evaluation assets were $17.8 million, of which $15.6 million was in Australia and $2.2 million was in Hungary.

Australia - Beetaloo Basin, Northern Territory, Australia

During 2011, costs incurred in Australia were primarily for the testing and stimulation of the Shenandoah-1 well and for geological and geophysical analysis, engineering and analytical evaluations, and working with the Northern Land Council and Aboriginal Area Protection Agency for site clearances and necessary environmental studies.

During 2012, costs incurred in Australia were primarily for geological and geophysical analysis, engineering and analytical evaluations, and working with the Northern Land Council and Aboriginal Area Protection Agency for site clearances and necessary environmental studies.

Under the terms of Falcon Australia's exploration permit EP-99, which is not covered by the Hess Agreement, Falcon Australia must spend a minimum of $1.5 million by 31 December 2013 in collecting 2D seismic data on acreage within exploration permit EP-99. Falcon Australia intends to meet this commitment either through a farm-out arrangement or through its own resources.

South Africa - Karoo Basin, South Africa
On receipt of an approved exploration right in South Africa, the Group will be required to make a payment to the South African government of approximately $0.7 million as part of the process to obtain an approved work programme and an exploration permit.

Hungary - Makó Trough, Hungary
As at 31 December 2012, the Company's 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 $242 million**,** including a decommissioning provision of approximately $11 million. The net increase in 2012 includes an increase of $1.5 million to the decommissioning provision for the seven existing well bores.

The Group is not planning any independent technical operations in Hungary other than joint operations with NIS, and as such no material capital expenditures are expected.

Debt and Equity Capital

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. As noted above on 14 March 2013 the Group announced its application for admission to trading on the AIM market of the London Stock Exchange (symbol: FOG) and the ESM market of the Irish Stock Exchange (symbol: FAC) of the Company's existing share capital and the additional 120,381,973 new common shares in the capital of Falcon to be issued pursuant to the concurrent conditional brokered private placement of new common shares at a price of Stg14 pence (CDN$0.215) per share to raise gross proceeds of $25 million (£16.9 million). Trading in these shares commenced on AIM and ESM on 28 March 2013.

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DISCLOSURE OF OUTSTANDING SHARE DATA

The following is a summary of the Company's outstanding share data as at 31 December 2012 and 12 April 2013:

Class Of Securities	31 December 2012	12 April 2013
Common Shares [4]	696,954,500	817,336,473
Stock Options [3]	32,837,000	29,764,500
Private Placement Warrants[1]	65,287,500	65,287,500
Hess Warrants[2]	10,000,000	10,000,000

Notes:-

(1) Warrants to purchase 65,287,500 Common Shares at a price of $0.19 (CDN$0.18/ CDN$0.19) per Common Share were issued to shareholders in 2011 in connection with the Falcon Private Placement and expire in February and April 2014.

(2) Warrants to purchase 10,000,000 Common Shares at a price of $0.19 (CDN$0.19) per Common Share were issued to Hess on 13 July 2011 in connection with the Hess transaction. The Hess Warrants are exercisable commencing on 14 November 2011, and expire on 13 January 2015.

(3) Eoin Grindley (Chief Financial Officer) is, pursuant to his employment contract, entitled to 3,000,000 stock options which have not yet been granted.

(4) On 14 March 2013 the Group announced its application for admission to trading on the AIM market of the London Stock Exchange (symbol: FOG) and the ESM market of the Irish Stock Exchange (symbol: FAC) of the Company's existing share capital and the additional 120,381,973 new common shares in the capital of the Company to be issued pursuant to the concurrent conditional brokered private placement of new common shares at a price of Stg14 pence (CDN$0.215) per share to raise gross proceeds of $25 million (£16.9 million). Dealings in these shares commenced on AIM and ESM on 28 March 2013.

LEGAL MATTERS

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

TRANSACTIONS WITH NON-ARM'S LENGTH PARTIES AND RELATED PARTIES

Services – Directors and Officers
The following are the related party contracts with Directors and Officers:

Dr. György Szabó Consulting Agreement
On 27 February 2009, Dr. György Szabó entered into a consulting agreement (the "GS Consulting Agreement") with Falcon TXM ("TXM"), pursuant to which Dr. Szabó agreed to act as Managing Director of TXM, to perform certain oil and gas services for TXM and to not compete directly or indirectly with TXM during his employment with TXM. Dr. Szabó is paid a monthly fee of $5,000. The GS Consulting Agreement contains standard confidentiality provisions. TXM may terminate the GS Consulting Agreement at any time, with or without cause, for any lawful reason whatsoever, upon TXM providing Dr. Szabó with sixty days' prior written notice.

The GS Consulting Agreement expired on 31 December 2009, however Dr. Szabó has continued to provide general managerial services to TXM and to receive the same monthly fee. Dr. Szabó was paid $60,000 pursuant to the GS Consulting Agreement in 2012.

P&S Consulting Agreement
On 4 May 2005, P&S Mérnöki Kereskedelmi-Tanácsadó Bt. ("P&S") entered into a consulting agreement (the "P&S Agreement") with TXM, pursuant to which P&S agreed to provide certain consulting services to TXM in connection with TXM's objectives of drilling wells on the Makó and Tisza licences. The P&S Agreement was amended on 28 November 2005 and further amended on 1 June 2006, 1 January 2008, 1 January 2009 and 1 April 2010. P&S is wholly-owned by a family member of Dr. Szabó, a current Director of the Company.

Under the terms of the P&S Agreement, TXM was obligated to pay P&S a monthly services fee of HUF 750,000. The P&S Agreement contains standard confidentiality provisions and provides that P&S shall not compete with TXM during the term of the P&S Agreement.

TXM may terminate the P&S Agreement at any time, with or without cause, for any lawful reason whatsoever, upon TXM providing P&S with 30 days prior written notice. TXM and P&S have further amended the terms of the P&S Agreement by oral agreement. Pursuant to the amended P&S Agreement, P&S is paid a monthly fee of $8,500 (effective 1 January 2013) (2012: $10,000) plus reasonable expenses incurred by Dr. Szabó as an employee of P&S, such amounts thereafter paid to Dr. Szabó from P&S.

Dr. Gábor Bada
On 28 December 2012, Dr. Bada entered into an employment agreement (the "Bada Employment Agreement") with TXM pursuant to which Dr. Bada agreed, subject to certain conditions, to perform certain geological services for TXM. In addition, on 1 January 2013, Dr. Bada verbally agreed the terms on which he was to provide geological services to TXM as a consultant. Dr. Bada will be paid a consultancy fee of $20,000 in 2013 in relation to this work. The Bada Employment Agreement contains standard confidentiality provisions.

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 ESTIMATES

Preparation of financial statements pursuant to IFRS requires a significant number of judgemental assumptions and estimates to be made. This impacts the income and expenses recognised in the statement of operations and comprehensive loss together with the valuation of the assets and liabilities in the statement of financial position. Such estimates and judgements are based on historical experience and other factors, including expectation of future events that are believed to be reasonable under the circumstances and are subject to continual re-evaluation. It should be noted that the impact of valuation in some assumptions and estimates can have a material impact on the reported results.

The following are key sources of estimation uncertainty and critical accounting judgements in applying the Group's accounting policies:

Critical judgments

(i) Exploration and evaluation assets
The carrying value of exploration and evaluation assets was $74.0 million at 31 December 2012 (2011: $71.0 million). The Company has determined that there are no indicators of impairment present in accordance with IFRS 6 "Exploration for and evaluation of mineral interests" and thus impairment evaluations were not performed on these assets.

Management's conclusion that no facts or circumstances exist that suggested the exploration and evaluation assets may be impaired required judgment based on experience and the expected progress of current exploration and evaluation activities and the successful completion of farm-out projects.

The critical judgments are:

Beetaloo Basin, Northern Territory, Australia:- Under the terms of the Hess Agreement, Hess has the option until 30 June 2013 to acquire a 62.5% working interest in the Hess Area of Interest, by committing to drill and evaluate five exploration wells at Hess' sole cost, one of which must be a horizontal well. In the event that Hess decides not to drill and evaluate five wells, its obligations under the Hess Agreement will cease and Falcon Australia will become responsible for 100% of any exploration and development costs of the Hess Area of Interest. If Falcon Australia were unable to secure participation by a new farm-in or joint venture partner for the development of the Hess Area of Interest, its ability to develop and realise its investment in the asset could be significantly curtailed. A decision by Hess not to exercise its option would have an adverse effect on the Group's business, prospects, financial condition and results of operations. Management have assumed that Hess will exercise its option.

Makó Trough, Hungary: Under the terms of the NIS Agreement, NIS will earn 50% of the net production revenues from the initial three wells being drilled in the Algyö Play, and will have an option to acquire a right of first negotiation for future drilling operations in the Algyö Play, sharing any potential future costs and revenue with the Group, on terms to be negotiated. In the event that NIS decide not participate in any further drilling operations in the Algyö Play, Falcon will become responsible for 100% of any exploration and development costs in the Algyö Play under the Makó Production Licence. If the Group were unable to secure participation by a new farm-in or joint venture partner for the development of the Algyö Play, its ability to develop and realise its investment in the asset could be significantly curtailed. This could have an adverse effect on the Group's business, prospects, financial condition and results of operations. Management have assumed that the NIS agreement will yield results.

Critical estimates

(ii) Going concern

The consolidated financial statements have been prepared on the going concern basis. In considering the financial position of the Group, the Company has considered the forecasted operating and capital expenditures for the foreseeable future and cash flows relating to its financing. Forecasting those cash flows requires significant judgment when estimating expected operating expenditure, capital expenditure, proceeds from share issuances and cash outflows required to redeem the company's convertible debt.

(iii) Decommissioning Provision

The decommissioning provision represents the Company's best estimate of the costs involved in the various exploration and production licence areas to return them to their original condition in accordance with the licence terms. These estimates include certain management assumptions with regard to future costs, inflation rates and discount rates.

NEW ACCOUNTING PRONOUNCEMENTS

Several new standards and amendments to existing standards and interpretations, which have been issued by the IASB, and which are expected to apply to the Group are not yet effective and have not been applied in preparing these financial statements. The Group does not expect adoption of these new standards and interpretations, to have a material impact on the financial statements. The Group's initial view of the impact of these accounting changes is outlined below:

Pronouncement	Nature of change	Impact
Amendments to IAS 1, 'Presentation of financial statements' *Effective date:- Financial periods beginning on or after 1 July 2012*	The amendments to IAS 1, 'Presentation of Financial Statements' require companies to group together items within other comprehensive income (OCI) that may be reclassified to the Statement of operations. The amendments also reaffirm existing requirements that items in OCI and profit or loss should be presented as either a single statement or two separate statements.	Not significant.
Amendments to IAS 19, 'Employee benefits' *Effective date:- Financial periods beginning on or after 1 January 2013*	The amended standard eliminates the option for deferred recognition of all changes in the present value of the defined benefit obligation and in the fair value of plan assets (including the corridor approach). In addition, the amended standard requires a net interest approach, which will replace the expected return on plan assets, and will enhance the disclosure requirements for defined benefit plans.	Not significant.
Amendments to IAS 32 and IFRS 7 'Financial Instruments' on Asset and Liability Offsetting *Effective date:- IFRS 7 : Financial periods beginning on or after 1 January 2013* *Effective date:- IAS 32: Financial periods beginning on or after 1 January 2014.*	These amendments are to the application guidance in IAS 32, 'Financial Instruments: Presentation' that clarify some of the requirement for offsetting financial assets and financial liabilities on the balance sheet. The IASB has also published an amendment to IFRS 7, 'Financial Instruments: Disclosures'. These new disclosures are intended to facilitate comparison between those entities that prepare IFRS financial statements to those that prepare financial statements in accordance with US GAAP.	Not significant.
IFRS 10,'Consolidated Financial Statements' *Effective date:- Financial periods beginning on or after 1 January 2013*	This standard replaces IAS 27, 'Consolidated and Separate Financial Statements' and SIC-12, 'Consolidation – Special Purpose Entities'. It establishes a single control model that applies to all entities, including those that were previously considered special purpose entities under SIC-12. An investor controls an investee when it is exposed, or has rights to variable returns from the investee, and has the ability to affect those returns through its power over the investee. The assessment of control is based on all facts and circumstances and the conclusion is reassessed if there is an indication that there are changes in facts and circumstances.	Not significant.
IFRS 11,'Joint arrangements' *Effective date:- Financial periods beginning on or after 1 January*	IFRS 11 supersedes IAS 31, 'Interests in Joint Ventures' and SIC-13, 'Jointly-controlled Entities – Nonmonetary Contributions by Venturers'. IFRS 11 classifies joint arrangements as either joint operations or joint ventures and	The Group is currently assessing the impact of IFRS 11, given its post balance sheet

Pronouncement	Nature of change	Impact
2013	focuses on the nature of the rights and obligations of the arrangement. IFRS 11 requires the use of the equity method of accounting for joint arrangements by eliminating the option to use the proportionate consolidation method.	announcement with NIS.
IFRS 12, ' Disclosure of Interest in Other Entities' *Effective date:- Financial periods beginning on or after 1 January 2013.*	IFRS 12 establishes the provision of information on the nature, associated risks, and financial effects of interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities, as disclosure objectives. IFRS 12 requires more comprehensive disclosure, and specifies minimum disclosures that an entity must provide to meet the disclosure objectives. While the standard is effective for annual periods beginning on or after 1 January 2013, entities are permitted to include any of the disclosure requirements in IFRS 12 into their consolidated financial statements without early adopting IFRS 12.	The Group is assessing the impact of adopting IFRS 12.
IFRS 13, ' Fair Value Measurement' *Effective date:- Financial periods beginning on or after 1 January 2013*	In May 2011, the IASB issued IFRS 13, 'Fair Value Measurement' which establishes a single source of guidance for fair value measurement under IFRS. IFRS 13 provides a revised definition of fair value and guidance on how it should be applied where its use is already required or permitted by other standards within IFRS and introduces more comprehensive disclosure requirements on fair value measurement.	Not significant.
IAS 27 (revised), ' Separate Financial Statements' *Effective date:- Financial periods beginning on or after 1 January 2013*	IAS 27 (revised) includes the provisions on separate financial statements that are left after the control provisions of IAS 27 have been included in the new IFRS 10.	Not significant.
IAS 28 (revised),'Investments in Associates and Joint Ventures' *Effective date:- Financial periods beginning on or after 1 January 2013*	IAS 28 (revised) includes the requirements for joint ventures, as well as associates to be equity accounted following the issue of IFRS 11.	Not significant.
Improvements to IFRSs (2009-2011) *Effective date:- Financial periods beginning on or after 1 January 2013*	The annual improvements process provides a vehicle for making non-urgent but necessary amendments to IFRSs.	Not significant
IFRS 9,'Financial instruments' *Effective date:- Financial periods beginning on or after 1 January 2015*	IFRS 9 is the first step in the process to replace IAS 39, 'Financial instruments: recognition and measurement'. The first stage of IFRS 9 dealt with the classification and measurement of financial assets and was issued in November 2009. An addition to IFRS 9 dealing with financial liabilities was issued in October 2010. The main changes from IAS 39 are summarised as follows: • the multiple classification model in IAS 39 is replaced with a single model that has only two classification categories: amortised cost and fair value; • classification under IFRS 9 is driven by the entity's business model for managing financial assets and the contractual characteristics of the financial assets; • the requirement to separate embedded derivatives from financial asset hosts is removed; • the cost exemption for unquoted equities is removed; • most of IAS 39's requirements for financial liabilities are retained, including amortised cost accounting for most financial liabilities; • guidance on separation of embedded derivatives will continue to apply to host contracts that are financial liabilities; and • fair value changes attributable to changes in own credit risk for financial liabilities designated under the fair value option other than loan commitments and financial guarantee	The Group is assessing the impact of adopting IFRS 9. The impact is not expected to be significant. The impact of IFRS 9 may change as a consequence of further developments resulting from the IASB's financial instruments project.

Pronouncement	Nature of change	Impact
	contracts are required to be presented in the statement of comprehensive income unless the treatment would create or enlarge an accounting mismatch in profit or loss. These amounts are not subsequently reclassified to the Statement of operations but may be transferred within equity.	

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. The Board has approved the MD&A as presented.

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