FINANCIAL & OPERATING HIGHLIGHTS
(in United States dollars (tabular amounts in thousands) except as otherwise noted)

	Three months ended December 31,			Twelve months ended December 31,		
	2013	**2012**	**Change**	**2013**	**2012**	**Change**
Financial						
Crude oil and natural gas revenues	$ 33,797	-	-	$ 65,508	-	-
Cost of sales	(9,462)	-	-	(18,620)	-	-
Depletion, Depreciation & Amortization	(16,206)			(34,768)		
Gross Profit	8,129	-	-	12,120	-	-
Gross Profit before DD&A	24,335	-	-	46,888	-	-
Income (loss) Before Tax	(39,006)	(4,427)	(781%)	(65,461)	(10,581)	(519%)
Income (loss) After Tax	31,553	(4,427)	813%	29,466	(10,581)	378%
Per share – basic ($)	0.09	(0.01)		0.08	(0.04)	
Per share – diluted ($)	0.09	(0.01)		0.08	(0.04)	
Funds Flow[1][2]	28,225	(4,601)	713%	31,324	(4,553)	788%
Per share – basic ($)	0.08	(0.01)		0.09	(0.02)	
Per share – diluted ($)	0.08	(0.01)		0.09	(0.02)	
Adjusted EBITDA[1][2]	27,936	(4,601)	707%	46,956	(10,737)	538%
Per share – basic ($)	0.08	(0.01)		0.13	(0.04)	
Per share – diluted ($)	0.08	(0.01)		0.13	(0.04)	

	As at December 31	
	2013	**2012**
Cash and cash equivalents	$ 19,808	$ 15,579
Restricted cash	85,114	9,808
Working capital surplus[1]	79,075	(34,897)
Secured bonds	$ 262,450	$ -
Common shares, end of period	366,831	324,905
Fully diluted, end of period[1]	369,225	351,985
Weighted average common shares - basic	360,849	273,611
Weighted average common shares–fully diluted	363,078	273,611

	Three months ended December 31,			Twelve months ended December 31,		
	2013	**2012**	**Change**	**2013**	**2012**	**Change**
Operational						
Crude oil and natural gas production (boepd)[3][4]						
Crude oil	2,320	-	-	1,694	-	-
Natural Gas	765	-	-	736	-	-
Total	3,085	-	-	2,430	-	-
Realized sales prices						
Crude oil ($/boe)	112.15	-	-	108.35	-	-
Natural Gas ($/mmcf)[5]	12.88	-	-	10.07	-	-
Average ($/boe)	103.84	-	-	97.63	-	-
Operating costs[1][6] ($/boe)	$ 24.94	-	-	$ 27.75	-	-
Netback[1] ($/boe)	$ 78.90			$ 69.88		

(1) Non-GAAP measure – see "non-IFRS Measures" section within MD&A.
(2) See reconciliation on page 5.
(3) Adjusted for start of production of Huntington on April 12, 2013.
(4) Based on 15.75% (excludes 1.8% royalty) working interest of volumes from Huntington.
(5) Q3 2013 revenue accrual had been understated by $916,000; this amount has been included in the Company's Q4 2013 revenue. Realized sales prices have been normalized. Revenue numbers for Q3 2013 have not been restated.
(6) Q3 2013 operating costs had been understated by $2.1 million; this amount has been included in the Company's Q4 2013 operating costs. Realized operating costs have been normalized. Operating costs for Q3 2013 have not been restated.

KEY PROJECT UPDATES

Huntington

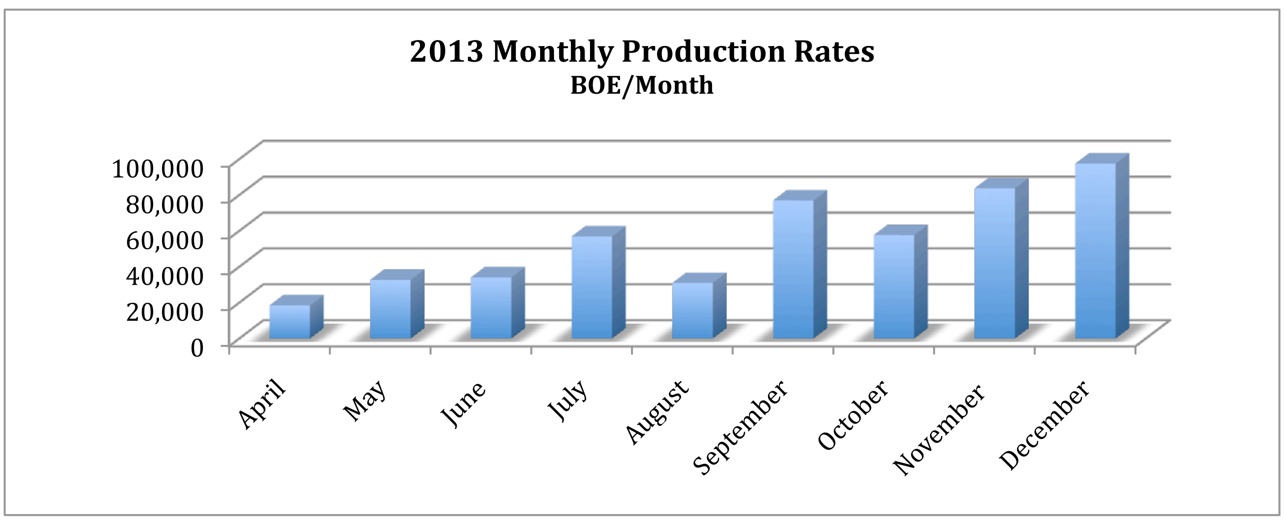
- On February 22nd, 2013, Iona, through Iona UK, acquired Carrizo UK Huntington Limited which included a 15% working interest in License P1114 of UK North Sea Block 22/14b containing the near-producing Huntington Forties oil field development ("Huntington"), the Jurassic Fulmar discovery ("Maxwell"), the undrilled potential extension of the Jurassic Fulmar ("Lobe 2"), and two Triassic Skagerrak structures, one of which includes a drilled discovery. Additionally, the acquisition included royalties equivalent to 2.55% of gross oil and gas production from License P1114 payable by the Huntington joint venture partners, and Carrizo UK's ring-fenced tax losses totaling $125 million.

- Also as part of the Huntington acquisition, Iona UK acquired a 100% interest in Block 22/14d located in the Central North Sea, immediately to the south of Huntington, containing an undrilled extension of the Jurassic Fulmar ("Lobe 3"), and a discovered and tested extension of the Triassic Skagerrak. Iona plans to remap both the Jurassic targets and Triassic discoveries in the near-term, and future appraisal could see these as candidates for development through the existing infrastructure at the producing Huntington field.

- The Huntington field commenced oil production on April 12, 2013, with gross production initially limited to 7,300 boepd, prior to first gas export in June which allowed oil production levels to be increased.

- In early September, Huntington production was curtailed by restrictions on gas export due to problems in the Central Area Transmission System ("CATS") gas export pipeline. These restrictions continued from September through November and, following a period of inclement weather in December, Huntington returned to plateau production levels and was producing at peak rates above 34,700 boepd (6,100 boepd net to Iona) at year-end.

- Net production from the Huntington field to Iona during the period from first oil (April 12, 2013) until December 31, 2013 was 2,149 boepd (Q4 2013 - 2,947 boepd), including the 2.55% royalty, and the Huntington reservoir and FPSO continued to perform well with Q4 2013 system availability of 94%.



- On March 1, 2014, the Voyageur FPSO passed its Performance & Reliability Test and as of March 31st 2014, the field had produced 5.1 million barrels of oil equivalent, with Iona's net share of production totaling 0.9 million barrels of oil equivalent. Iona's Q1 2014 average production at Huntington increased 34% over Q4 2013, from 2,974 boepd to 3,959 boepd, as operational and weather-related downtime at the field continued to improve. Further, cargo schedule optimization has increased oil liftings, taking advantage of good weather windows as and when available.

- On April 12, 2014, Huntington production was suspended as work commenced to replace a number of straub couplings that are part of the inert gas system on the floating production, storage and offloading ("FPSO") facility. On April 24, 2014, the Operator, E.ON E&P UK Ltd, informed the partners that the replacement work had been completed ahead of schedule and that production restart had commenced. However, on April 26, 2014 the Huntington partnership was advised that due to an unplanned shutdown issue involving the CATS riser system, all fields producing through the system would be shut in until May 1, 2014.

Huntington Jurassic Fulmar ("Maxwell")

- Relating to the deeper Maxwell discovery which lies beneath the producing Huntington Forties field, a subsequent phase of development is under evaluation by the Huntington joint venture partners to submit an FDP, to conduct engineering work in 2015, and to set a first oil target in 2016. Further appraisal and development of the Fulmar horizon may follow depending on the geoscience evaluation of the overall extent of this reservoir to include Iona's 100% owned Block 22/14d.

Trent & Tyne

- The net production from the Trent & Tyne fields to Iona during the year was 2.96 MMcf/d.

- The net average daily production rate from Trent & Tyne to Iona during the three and twelve months ended December 31, 2013 was 2.1 MMcf/d and 3.0 MMcf/d respectively, which was severely reduced as a result of remedial works at the onshore reception terminal in addition to restricted production from the T6 well due to the intermittent performance of the fresh water maker at Tyne and further exacerbated by the past winter's exceptionally stormy weather, which restricted manned interventions to effect repairs.

- The Tyne 44/18-T6 ("T6") well was completed in January 2013 as a production well and flow tested at an average rate of 25 MMcf/d with a peak rate of 28 MMcf/d. Until late 2013, T6 production was consistently above 25 MMcf/d and exceeding expectations. Late in 2013 the T6 well began experiencing technical difficulties, and production dropped from 28 MMcf/d to 12 MMcf/d. The well was taken offline to analyze the problem.

- In the operating envelope of the Tyne field, and in particular the T6 well, salt deposition in the wellbore tubulars is a significant risk to production. As super-saline formation water enters the wellbore tubulars it experiences a drop in both temperature and pressure. This causes salt to drop out of solution and deposit in the well. It is a well-known issue in the gas fields of the UK Southern Gas Basin and elsewhere with highly saline formation waters. Standard industry practice is to install a water washing system to the wells. Fresh water is pumped down the wells and this washes salt deposits to surface. A water maker takes sea water and, by reverse osmosis, generates fresh water for the water washing system. Salt build-up is sufficiently quick to preclude producing wells such as T6 without continual water washing. It is routine procedure to suspend production while the water maker is out of commission. Operational improvements to enhance the performance and reliability of the Tyne water maker are being implemented and should be rectified during the second half of 2014.

Orlando

- On February 21, 2013, Iona UK completed the acquisition of its partners' interests, MPX North Sea Limited (30%) and Sorgenia E&P (UK) Ltd (35%), in the Orlando oil field in exchange for approximately $48.25 million and the obligation to make future payments out of production totaling $29 million.

- The development plan for Orlando comprises the re-entering of the suspended 3/3b-13z well, drilling a 3,000 foot horizontal producer, and completion with dual electric submersible pumps. Additionally, a subsea pipeline, power supply and control umbilical are expected to be laid between the well-head and the Ninian Central Platform ("NCP") approximately 10 km to the south west of the Orlando field. Engineering modifications are expected to be completed at NCP allowing tie-in and first production shortly after completing the development well.

- It was originally contemplated that each of these items would be completed by 2015, enabling first oil from Orlando in the second half of the year. Subsequent to December 31, 2013, the Company has determined that some of these items will not be completed during 2014 and 2015, and Iona now aims to achieve first oil from Orlando as early as possible in 2016.

- The manufacture of line pipe and Xmas trees is substantially complete. The copper cores for the umbilical are also complete and delivered to the umbilical assembly plant. Manufacture of the control system is ongoing and contractual arrangements for the balance of the project supply chain are in the process of being finalized. Additionally, piping tie-ins to the NCP have now been completed.

- On April 16, 2013 the Department of Energy and Climate Change ("DECC") advised the Orlando joint venture partners that it had approved the Orlando Field Development Plan submitted by the partners.

Kells

- Kells is currently slated for development through NCP following tie-in of Orlando to the same facility. The Kells development plan comprises two subsea production wells, an oil pipeline, a control umbilical, and some pipework modifications at NCP. An FDP has been submitted and project activity will be phased through 2015 and 2016, with first oil expected in the second half of 2016. A subsequent water injection project is planned to unlock additional reserves. This 2017 project will involve the laying of water injection and gas lift lines, and the conversion of the second well to water injection service.

Orlando & Kells (Sale of 25% working interest)

- On February 21, 2013, Iona UK completed its sale of a 25% working interest in its UK North Sea Orlando and Kells fields to Volantis Exploration for total gross proceeds of $34 million and pro-rata share of future staged payment obligations totaling $8.5 million. Iona acquired its 100% operated working interest in the Orlando and Kells fields for USD 5.35/boe. This accretive partial disposition saw the company recognize a sale price of USD 7.03/boe.

Ronan & Oran

- Since acquiring these oil discoveries in the 27th licencing round, Iona has commenced reprocessing 270 km2 of 3D seismic data over the region, and has conducted more detailed subsurface mapping of Ronan & Oran that suggests the area of the discoveries may be greater than previously thought. The three discovery wells all encountered oil 'down to' the base of the reservoir without encountering oil-water contacts. Iona believes that subsurface mapping has shown the potential to add significant resources through appraisal drilling which exist below known oil levels, and that a potential oil-water contact 150 ft deeper could be mapped out to the spill point lying to the northeast. A preliminary appraisal location has been selected to penetrate and test the extension of this oil column deeper into the basin to determine the extent of these resources.

- The reprocessed 3D data should be received in July, after which a final subsurface appraisal location will be confirmed. Iona is currently contemplating the appraisal drilling in early 2015, and has initiated the permitting, site survey, and procurement of a semi-submersible rig to pursue this opportunity.

CORPORATE HIGHLIGHTS

- Having produced approximately 690,000 boe net in 2013, the Company's reserves remained robust, with Gaffney, Cline & Associates Ltd. ("GCA") assigning 34 MMboe 2P reserves to Iona as at December 31, 2013 (34.3 MMboe at December 31, 2012, from the Company's Reserve Report prepared by GCA), in part due to additional reserves of 650,000 boe being attributed to the Huntington field.

- The Company earned record revenues of $33.8 million and $65.5 million for the three and twelve month periods ended December 31, 2013 respectively.

- 4th quarter netbacks of $78.9/boe and netbacks for the year ended December 31, 2013 of $69.9/boe.

- Record funds flow of $28.2 million and $31.3 million for the three and twelve month periods ended December 31, 2013 respectively.

- On February 21, 2013, Iona closed a bought-deal private placement of common shares for an aggregate amount of CAD$23 million. Pursuant to the private placement the Company issued 41,818,603 common shares at $0.55 per share. Concurrently, Iona UK signed a Senior Secured Borrowing Base Facility for up to $250 million with a group of three banks led by Bank of America Merrill Lynch, Lloyds TSB Bank plc, and BNP Paribas. Further, Iona UK completed a $60 million structured energy derivative transaction with Britannic Trading Ltd., a subsidiary of BP Oil International Limited, in addition to entering into a Marketing and Offtake Agreement with BP Oil International Limited.

- On September 27, 2013, Iona UK issued $275 million senior secured bonds (the "Bonds"). Proceeds from the Bond were used to repay the Company's Senior Secured Borrowing Base Facility in full and to offset 3.1 million call options through a mirrored call structure, with the balance of the proceeds being allocated towards funding the delivery of the Orlando and Kells projects to first oil.

- The Company has tax pools of approximately $321 million and does not expect to pay UK taxes until 2017 or later.

- The Company's current production is not subject to any crown or third party royalties on any revenues, now or in the foreseeable future.

HIGHLIGHTS SUBSEQUENT TO THE YEAR END

Subsequent to the year-end the Company, through its wholly owned UK subsidiary, Iona UK Developments Co Limited, entered into a Sale and Purchase Agreement ("SPA") with Perenco UK Limited ("Perenco"), to purchase Perenco's remaining 80% working interest, rights, and obligations in the Trent & Tyne fields (including the Trent East Discovery Area).

Upon satisfaction of certain conditions as set out in the SPA, the Company shall pay to Perenco a sum of $20,000,000, adjusted pursuant to any adjustments as per the SPA, and assume all decommissioning liabilities in relation to the Licenses being purchased. Payment shall be made no later than six (6) calendar months after the date of the SPA or on such later date as agreed in writing.

Subsequent to the year-end the Company appointed Mr. Richard Ames as Iona's Executive Vice President. Mr. Ames is currently a Director of Iona. Mr. Alan Curran will remain as Chief Operating Officer until his departure in June 2014 and Mr. Graham Heath continues his roles as Interim Chief Financial Officer and VP Corporate Development until a permanent replacement is found for the role of CFO. Mr. Ames has 32 years of broad range experience in the oil and gas industry with senior executive roles in full cycle oil and gas exploration and production, information technology and oil and gas services.

MANAGEMENT DISCUSSION AND ANALYSIS

Change in presentation currency

This Management discussion and Analysis is presented in United States dollars ("US dollars"). In 2013, the Company changed its presentation currency from the Canadian dollars ("CAD") to the US dollar. The change in presentation currency is to better reflect the Company's business activities and to improve investors' ability to compare the Company's financial results with other publicly traded businesses in the oil and gas industry. In making this change to the US dollar presentation currency, the Company followed the guidance in IAS 21 *The Effects of Changes in Foreign Exchange Rates* and have applied the change retrospectively as if the new presentation currency had always been the Company's presentation currency. In accordance with IAS 21, the financial statements for all years and periods presented have been translated to the new US dollar presentation currency. For the 2012 comparative balances, assets and liabilities have been translated into the presentation currency (US dollars) at the rate of exchange prevailing at the reporting date. Items impacting income (loss) or comprehensive income (loss) were translated at the average exchange rates for the reporting period, or at the exchange rates prevailing at the date of transactions.

Business of the Company

Iona is an oil and natural gas acquisition, appraisal, and development corporation active through its 100% wholly owned United Kingdom subsidiary Iona Energy Company (UK) Limited ("Iona UK") in the United Kingdom's Continental Shelf ("UKCS").

Over the last year to December 31, 2013, the Company has continued its efforts to acquire strategically aligned assets for its UK portfolio. Iona seeks low-cost, proven undeveloped acquisition targets that are proximate to infrastructure willing and able to accept its future production, and where sub-sea tiebacks can be utilized. Employing this strategy facilitates the Company's pursuit of profitable oil and gas production through the effective management of finding and development costs, initial capital expenditure, and lower long-term per barrel operating expenditure and tariffs.

The following Management's Discussion and Analysis ("MD&A") of Iona Energy Inc. ("Iona" or "the Company") have been prepared in accordance with International Financial Reporting Standards ("IFRS") and should be read in conjunction with the consolidated financial statements and accompanying notes of the Company as at and for the year ended December 31, 2013, the Annual Information Form ("AIF") for the year ended December 31, 2013, the MD&A for the year ended December 31, 2012 and the audited consolidated financial statements as at and for the year ended December 31, 2012. Copies of these documents and additional information about Iona are available on SEDAR at www.sedar.com.

This MD&A is dated April 29, 2014. All currency amounts are expressed in United States Dollars ("$") unless otherwise stated.

Statements throughout this MD&A that are not historical facts may be considered “forward-looking statements”, including without limitation, statements regarding Iona's plans and timelines for the development of its properties, statements regarding estimates of the proved reserves, probable reserves, possible reserves, as well as estimates of the net present value of future net revenue of proved reserves, probable reserves, and possible reserves, future obligations under Iona’s bond agreement and hedging arrangements including the Payment Swap (as defined herein), statements regarding potential increases in working interests, and statements regarding estimated production rates. These forward-looking statements sometimes include words to the effect that management believes or expects a stated condition or result. All estimates and statements that describe the Company’s objectives, goals or future plans are forward-looking statements. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties and actual results could differ materially from those currently anticipated. These risks and uncertainties include, but are not limited to: the risk that Iona's development plans change as a result of new information or events, the risk that drilling results differ materially from management's current estimates, the risk that actual production rates will be significantly lower than estimated peak production rates, the risk that Iona is not able to access the proceeds of the Bond offering, changes in market conditions, law or government policy, the risk that the anticipated increase in Trent & Tyne working interest is not completed, operating conditions and costs, operating performance, demand for oil and gas and related products, price and exchange rate fluctuations, commercial negotiations or other technical and economic factors. Forward-looking statements are based on current expectations, estimates and projections of future production and capital spending as at the date of this MD&A and the Company assumes no obligation to update or revise forward-looking statements to reflect new events or circumstances, except as required by law.

Financial outlook information contained in this MD&A about prospective results of operations, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management’s assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this MD&A should not be used for purposes other than for which it is disclosed herein.

Non-GAAP Financial Measures

Throughout this MD&A, the Company uses the terms “funds flow”, “funds flow per share - basic”. “funds flow per share – diluted”, “Adjusted EBITDA”, “Adjusted EBITDA per share - basic”, “Adjusted EBITDA per share – diluted”, “working capital” and “operating netback”. These terms do not have any standardized meaning as prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other issuers. Management uses working capital and operating netback measures. Working capital is calculated as current assets less current liabilities, and is used to evaluate the Corporation’s financial leverage. Operating netback is a benchmark common in the oil and gas industry and is calculated as total petroleum and natural gas sales, less production and transportation expenses, calculated on a per barrel equivalent (“boe”) basis of sales volumes using a conversion. Operating netback is an important measure in evaluating operational performance as it demonstrates field level profitability relative to current commodity prices. Working capital and operating netback as presented do not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities.

Funds flow is calculated based on cash flow from operating activities before changes in non-cash working capital. Adjusted EBITDA is calculated as net income before finance costs, derivative gains and losses, taxes, depletion, depreciation and amortization. Funds flow or Adjusted EBITDA per share - basic and funds flow or Adjusted EBITDA per share - diluted are calculated as funds flow or Adjusted EBITDA divided by the number of weighted average basic and diluted shares outstanding, respectively. Management utilizes funds flow and Adjusted EBITDA as key measures to assess the ability of the Company to finance dividends, operating activities, capital expenditures and debt repayments. Funds flow and Adjusted EBITDA as presented are not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS.

The following table reconciles cash flow used in operating activities to funds flow:

	2013	2012
Cash flow used in operating activities	$ **15,294**	$ (5,161)
Changes in non-cash working capital balances:		
Accounts receivable	**11,896**	1,547
Prepaid expenses	**(722)**	(106)
Inventory	**581**	-
Accounts payable and accrued liabilities	**4,275**	(833)
Funds Flow	$ **31,324**	$ (4,553)

The following table reconciles net income to Adjusted EBITDA:

		2013	$	2012
Net income	$	**29,466**		(10,581)
Income tax recovery (expenses)		**(94,927)**		-
Finance costs		**23,172**		-
Finance Income		**(20)**		(184)
Loss / (gain) on financial instruments		**30,917**		-
Impairment		**23,580**		-
Depletion, depreciation and amortization		**34,768**		28
	$	**46,956**	$	(10,737)

The terms "boe" and per barrel equivalent per day "boepd" are used in this MD&A. Boe and boepd may be misleading, particularly if used in isolation. A boe conversion ratio of cubic feet of natural gas to barrels of oil equivalent is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In this MD&A we have expressed boe using a conversion standard of 6 Mcf: 1 boe which is standard in the industry.

PRODUCTION & OPERATIONS UPDATE

Producing Assets

Huntington crude oil and gas production

Iona, through Iona UK, completed the acquisition of 100% of the issued and outstanding shares of Carrizo UK Huntington Limited ("Carrizo UK"). The transaction was completed on February 22, 2013 by way of a sale and purchase agreement dated December 27, 2012 among Iona, Iona UK and Carrizo Oil & Gas Inc. ("Carrizo Oil"). The acquisitions included a 15% working interest in License P1114 of UK North Sea Block 22/14b containing the near-producing Huntington Forties oil field development ("Huntington"), the Jurassic Fulmar discovery ("Maxwell"), the undrilled potential extension of the Jurassic Fulmar ("Lobe 2"), and two Triassic Skagerrak structures, one of which includes a drilled discovery. Additionally, the acquisition included royalties equivalent to 2.55% of gross oil and gas production from License P1114 (the "Royalty") payable by the Huntington joint venture partners, and Carrizo UK's ring-fenced tax losses totaling $125 million. Under the terms of the sale and purchase agreement, total consideration paid by Iona UK to Carrizo Oil was $143.6 million, including an additional deferred payment of $18.0 million which was paid to Carrizo Oil upon receipt of first oil revenues from the Huntington field. Also on closing Iona UK repaid Carrizo UK's debt and deferred hedging premiums at the completion date, which was $55.9 million.

Iona has determined that this transaction represents a business combination with Iona identified as the acquirer. Iona began consolidating the operating results, cash flows and net assets of Carrizo UK from February 22, 2013. Subsequent to the acquisition, Carrizo UK was renamed "Iona UK Huntington Ltd".

The Huntington Forties reservoir was brought on stream on April 12, 2013 at 7,300 bopd gross. Shortly after establishing initial gas export on June 4, 2013 from gas compression train B, a small leak in the low-pressure compression system necessitated the checking of some 400 flanges in the module. This was successfully completed on July 6. During this initial three month period of gas plant commissioning, oil production remained constrained at between 7,000 and 10,000 bopd gross by the need to stay within the gas flaring consents imposed by DECC. Through the course of July commissioning activities on train B were completed and peak oil and gas rates of 23,400 bopd and 19.6 MMcf/d gross were established. Commissioning activities on gas compression train A were hampered by persistent vibration problems. After a period of exhaustive testing and diagnostics, the source of the vibration was pinpointed in the drive unit and coupling. Replacement equipment was sourced and installed by the original equipment manufacturers.

On September 5, 2013 the Company reported production from the Huntington Oil Field of approximately 34,056 boepd gross (29,909 bopd of oil and 24.9 MMcf/d of natural gas). Net to Iona, daily peak production was approximately 6,000 boepd, which included the Royalty. As a result of the increased production at Huntington, Iona reached a new daily corporate production record of approximately 6,800 boepd.

On September 9, 2013 Iona was advised that Huntington gross production would be temporarily reduced to 13,000 boepd (some 40% of nameplate capacity) due to dry gas blending and processing issues in the CATS gas export system. CATS Operator BP advised that restrictions would likely be lifted progressively through the course of November and expected to be fully removed during December 2013.

On September 27, 2013, the Company satisfied all payments owed to Carrizo Oil for the Company's acquisition of its interest in the Huntington field. With this final Huntington acquisition payment the Company also acquired a 100% working interest in part of UKCS block 22/14d from Carrizo Oil. Block 22/14d, located in the Central North Sea and immediately to the south of Huntington, contains an undrilled extension of the Jurassic Fulmar ("Lobe 3"), and a discovered and tested extension of the Triassic Skagerrak. Huntington discovery well 22/14b-5 drilled by a previous operator tested at peak rates of up to 4,600 bopd and 1.6 MMcf/d from Maxwell, suggesting that development of this reservoir could extend the economic life of Huntington. Iona is considering joint venture development of Maxwell and appraisal drilling of the adjacent Fulmar Lobe 2. Additionally, work is ongoing to evaluate the recoverable resources within the Jurassic Fulmar and Triassic Skagerrak oil-bearing intervals, which Iona believes could be significant if tied back to the Huntington production facility. Future development engineering definition and appraisal could see these as candidates for development through the existing infrastructure at the producing Huntington field.

During Q4 2013, Iona produced on average 2,947 boepd (including royalty) from Huntington as the ramp-up continued to increase following the previously announced curtailment of production by the operator of CATS from mid-September through November. Following a period of inclement weather in December, Huntington returned to plateau production levels and was producing in excess of 34,500 boepd (6,100 boepd net to Iona) at year-end. The Huntington reservoir and FPSO continued to perform well, with Q4 2013 system availability of 94%.

Subsequent to December 31, 2013 GCA evaluated, effective as of December 31, 2013, the reserves and net present values of future revenue associated therewith, using forecast prices and costs. The proved and probable reserves from Huntington net to Iona based on a 15.75% interest (15% working interest and 0.75% differential lifting entitlement) are 4.59 MMboe (4.02 MMbbls of oil and 3.44 Bscf of gas), not including the additional royalty interest of 1.8%. By comparison, GCA had assigned 4.58 MMboe (4.14 MMbbls and 2.64 Bscf of gas) as at December 31, 2012, prior to the field producing approximately 640,000 boe net Iona in 2013. At this time, reserves will only be assigned to the Paleocene Forties and the Fulmar formation, which has been developed through four production and two water-injection wells to achieve the aforementioned capacity figures. The management views current reserves associated with Huntington as conservative, and believes updated static and dynamic reservoir models, to be agreed by the Huntington joint venture partnership in 2014, will see an increase in reserves at the field.

Trent & Tyne gas production

The T6 well reached total depth in December 2012 and was tied-in to the production system in January 2013. The well commenced production at rates exceeding Iona's expectations, as announced by Iona in January 2013. Iona understands that Perenco is currently assessing a short sidetrack of the T1Z well to reestablish production from a previously producing and un-depleted part of the field. Iona is awaiting the operator's guidance on the timing for the work program.

On completion of the T6 well, the acquisition of a 20% interest in Trent &Tyne from Perenco was considered complete under the accounting standard IFRS 3 Revised, Business Combinations. The Company has determined that this transaction represents a business combination with Iona identified as the acquirer. The accounting for this is detailed in the consolidated financial statements for the Company for the quarters ended March 31, June 30 and December 31, 2013.

The net average daily production rate from Trent & Tyne to Iona during the three and twelve months ended December 31, 2013 was 2.1 MMcf/d and 3.0 MMcf/d respectively. Production for the twelve month period was severely reduced as a result of remedial works at the onshore reception terminal. This resulted in complete production shutdown from February 12th through to April 11th. Further, production from the T6 well was also restricted as a consequence of intermittent performance of the fresh water maker at Tyne and was further exacerbated by the past winter's exceptionally stormy weather, which restricted manned-interventions to effect repairs.

In the operating envelope of the Tyne field, and in particular the T6 well, salt deposition in the wellbore tubulars is a significant risk to production. When super-saline formation water enters the wellbore tubulars it experiences a drop in both temperature and pressure. This causes salt to drop out of solution and deposit in the well. It is a well-known issue in the gas fields of the UK Southern Gas Basin and elsewhere with highly saline formation waters. Standard industry practice is to install a water washing system to the wells. Fresh water is pumped down the wells and this washes salt deposits to surface. A water maker takes sea water and, by reverse osmosis, generates fresh water for the water washing system. Salt build-up is sufficiently quick to preclude producing wells such as T6 without continual water washing. It is routine procedure to suspend production while the water maker is out of commission. Operational improvements to enhance the performance and reliability of the Tyne water maker are being implemented.

Subsequent to December 31, 2013 GCA evaluated, effective as of December 31, 2013, the reserves and net present values of future revenue associated therewith, using forecast prices and costs. The proved and probable reserves from Trent & Tyne net to Iona is 9.33 Bscf of gas based on its 20% working interest.

Developments

Orlando – A proven undeveloped oil discovery

The Orlando Field Development Plan ("FDP") was approved by DECC on April 16, 2013. The development plan contemplates the re-entering and drilling of the suspended 3/3b-13z well as a 3,000 foot horizontal producer, to be completed with dual electric submersible pumps. Additionally, a subsea pipeline, power supply and control umbilical are expected to be laid between the well-head and the Ninian Central Platform ("NCP") approximately 10 km to the south west of the Orlando field. Engineering modifications at the NCP will allow tie-in and first production shortly after completion of the development well. The manufacture of line pipe and Xmas trees is substantially finished. The copper cores for the umbilical are also complete and delivered to the umbilical assembly plant. Manufacture of the control system is ongoing and contractual arrangements for the balance of the project supply chain are in the process of being finalized. Additionally, piping tie-ins to the NCP have now been done.

It was originally contemplated that field development would be completed by 2015, enabling first oil from Orlando in the second half of the year. Subsequent to December 31, 2013, the Company has determined that some deliverables will not be completed during 2014 and 2015, and Iona aims to achieve first oil from Orlando as early as possible in 2016.

Iona is operator and holds a 75% working interest in the Orlando field. Volantis Exploration Limited, a wholly owned subsidiary of Atlantic Petroleum, owns the remaining 25% working interest following its acquisition from Iona on February 21, 2013.

Kells – Redevelopment of a proven field

Kells is slated for development through NCP following the tie-in of Orlando to the same facility. The Kells development plan comprises two subsea production wells, an oil pipeline, a control umbilical, and some pipework modifications at NCP. A draft FDP has been prepared and project activity will be phased through 2015 and 2016, with first oil expected in the second half of 2016. A subsequent water injection project is planned to unlock additional reserves. This 2017 project will involve the laying of water injection and gas lift lines, and the conversion of the second well to water injection service.

West Wick – Oil Discovery

Iona completed the acquisition of a 58.73% working interest in West Wick in August 2012 and is the operator on the block. West Wick is programmed for a three well subsea development. The development will comprise two producers and one injector. The most likely development is via offset field infrastructure; however, Iona is also considering stand-alone facilities and is in consultation with both the joint venture and the supply chain and engineering studies are ongoing. The Company expects to select a development approach and submit the associated FDP in 2014.

Ronan & Oran – Oil Discovery awaiting conversion to Reserves

Detailed subsurface mapping has been undertaken that has confirmed the extent of the Ronan and Oran Oil Discoveries within which oil-water contacts have yet to be established. This work has also matured the potential through appraisal drilling to add significant additional resources below the existing known oil levels and the potential deeper oil-water contacts out to the mapped spill points. Development concepts are under review.

Iona is currently contemplating the drilling of an appraisal well to locate the potential deeper oil-water contact and has initiated the permitting, site survey, and procurement of a semi-submersible rig to potentially commence drilling as early as Q1 2015.

Exploration

The Company's portfolio of assets will continue to grow through acquisitions, farm-ins and participation in license rounds.

CORPORATE TRANSACTIONS

On September 27, 2013, the Company's subsidiary, Iona UK closed $275 million in Bonds. The Bonds will mature on September 30, 2018. The Bonds carry an annual coupon rate of 9.5% payable semi-annually, were issued at 97.5% of par and are callable in whole or in part at the option of the Issuer at any time. The amortization profile is tailor-made to match the cash flow profile of Iona's existing asset base and is structured to enable Iona to bring Orlando, its next significant development project, on stream before commencing amortization payments. Commencing 30 months after the Settlement Date, the Bonds will amortize 15% of the issue amount every six months with a 25% final payment at maturity. The amortizations will be performed at the prevailing call option prices of 105%, 104%, 104%, 103% and 103% of par value with the residual amount payable at 102% of par value.

Proceeds from the Bond were used to repay the Company's Senior Secured Borrowing Base Facility in full and to offset 3.1 million call options with a mirrored call structure. Further, Bond proceeds satisfied all payments owed to Carrizo Oil & Gas, Inc. for the Company's acquisition of its interest in the Huntington field. The residual of the Bond proceeds were allocated towards funding the delivery of the Orlando and Kells projects to first oil.

The Bonds provide the Company with enhanced financial flexibility through improved access to cash flow from its producing assets, Huntington and Trent & Tyne, and increased debt financing for its upcoming development expenditures, while offering general terms and conditions which are less restrictive than those of the previous Loan Facility.

On March 21, 2014 the Bonds commenced trading on the Nordic ABM under the ticker IEC01 PRO.

SIGNIFICANT EVENTS SUBSEQUENT TO THE YEAR END

On January 28, 2014, the Company announced an operational update that, during Q4 2013 Iona produced on average 3,280 boepd as Huntington ramp-up continued to increase following the previously announced curtailment of production by the operator of CATS from mid-September through November. Following a period of inclement weather in December, Huntington returned to plateau production levels and was producing in excess of 34,500 boepd (6,100 boepd net to Iona) at year end. The Huntington reservoir and FPSO continued to perform well, with Q4 2013 system availability of 94%. January saw peak production above 35,450 boepd (6,220 boepd net to Iona) with average production net to Iona of approximately 4,100 boepd to January 15, 2014. Production was restricted from January 15 due to the FPSO storage tanks being full and extreme weather preventing the shuttle tanker connecting for offloading. The 16th cargo from Huntington was off-loaded and as of January 28 production had resumed.

On April 4, 2014, the Company announced an operational update relating to its Huntington Oil Field that during Q1 2014 Iona's average production at Huntington increased 34% over Q4 2013, from 2,947 boepd to 3,959 boepd, as operational and weather-related downtime at the field continued to improve. Throughout the month of March, the reservoir and FPSO continued to support strong production levels with peak rates above 34,300 boepd, and the Huntington joint venture continued to optimize the lifting schedule at the field, resulting in a record of 4 cargos offloaded during the last three weeks of the month bringing the total number of liftings to date to 23. During March, Huntington produced on average 26,327 boepd (4,620 boepd net to Iona), 6% lower than February 2014 average production of 28,000 boepd (4,914 boepd net to Iona), due to a planned maintenance shutdown at CATS earlier in the month. To the end of March, the field had produced over 5.1 million barrels of oil equivalent, with Iona's net share of production totaling 0.9 million barrels of oil equivalent. During Q1 2014, the Huntington joint venture realized prices centered on the Brent average of USD108.10/bbl, while average UK gas prices remained above $10.00/mcf.

On April 12, 2014, Huntington production was suspended as work commenced to replace a number of straub couplings that are part of the inert gas system on the floating production, storage and offloading ("FPSO") facility. On April 24, 2014, the Operator, E.ON E&P UK Ltd, informed the partners that the replacement work had been completed ahead of schedule and that production restart had commenced. However, on April 26, 2014 the Huntington partnership was advised that due to an unplanned shutdown issue involving the CATS riser system, all fields producing through the system would be shut in until May 1, 2014.

The joint venture partnership is at present analyzing optimization measures to debottleneck the Voyageur FPSO's current production capacity of 34,500 boe/d by an additional 10%. The results of the analysis should be complete by Q3 2014.

2013 RESULTS OF OPERATIONS

PRODUCTION AND PRICING

		2013	2012	%
Total Petroleum and natural gas production by product				
Crude Oil	bbl	**445,516**	-	-
Natural Gas	boe	**243,667**	-	-
Average Daily Production by product				
Crude Oil(1)	bopd	**1,694**	-	-
Natural Gas(1)	boepd	**736**	-	-

(1) adjusted for start of production for Huntington on April 12, 2013

Average net production for the year ended December 31, 2013 was 1,831 boepd. Production averaged 2,433 boepd net since April 12, 2013.

Of the total revenues of $65.5 million for the year ended December 31, 2013, $46.3 million was generated from oil production, $14.4 million was generated from gas production, $332,000 was generated from condensate and $4.5 million was generated through a gross overriding royalty interest in the Huntington field.

The average realized oil price for the year ended December 31, 2013 was $108 per bbl compared to average Brent oil prices in the period of $108 per bbl. The average realized gas price for the year ended December 31, 2013 was $10.07 per mcf of gas compared to average gas prices in the period of $10.00 per mcf.

REVENUE

		Three Months Ended December 31,			**Twelve Months Ended December 31,**		
		2013	2012	**%**	**2013**	2012	**%**
Petroleum and natural gas sales by product							
Crude oil	$	**25,208**	-	**-**	**46,295**	-	-
Natural gas		**5,350**	-	**-**	**14,398**	-	-
Royalty interest		**3,156**	-	**-**	**4,483**	-	-
Condensate		**83**	-	**-**	**332**		-
Total	$	**33,797**	-	**-**	**65,508**	-	-

Revenue was $33.8 million (2012 - $Nil) and $65.5 million (2012 – Nil) respectively for the three and twelve months ended December 31, 2013. The revenues generated during the fourth quarter were significantly higher than the previous quarters as a result of increased production from the Huntington Oil Field.

Oil sales volumes increased as a result of improved production from the Huntington field for the fourth quarter of 2013 compared to the third quarter of 2013. The decrease in gas sales in the fourth quarter compared to the previous quarters was due to a reduction in the Trent &Tyne gas volumes due to shut downs experienced throughout the third and fourth quarters.

Revenue was generated from the Trent & Tyne gas fields and from the Huntington oil field as discussed in *Key Projects Update*. There was no revenue generated from operations in 2012 as Huntington commenced production on April 12, 2013, while all revenues from Trent & Tyne accrued into a restricted cash account between the economic date of the Trent & Tyne acquisition and the completion of the T6 well in January 2013.

INVENTORY

Inventory for the year ended December 31, 2013 was $1.8 million (2012 - $Nil). Inventory relates to the Company's share of stock remaining in the FPSO storage tanks at December 31, 2013. Inventories of crude oil are valued at the lower of cost, using the average cost method, and net realizable value. Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location.

COST OF SALES

		Three Months Ended December 31,			Twelve Months Ended December 31,		
		2013	2012	**%**	**2013**	2012	**%**
Operating costs	$	**9,462**	-		**18,620**	-	-
Depletion and depreciation		**16,206**	-		**34,768**	-	-
Total	$	**25,668**	-		**53,388**	-	-

Cost of sales were $25.7 million (2012 - $Nil) and $53.4 million (2012 - $Nil) respectively for the three and twelve months ended December 31, 2013. Operating costs were $9.5 million (2012 - $Nil) and $18.6 million (2012 - $Nil) respectively for the three and twelve months ended December 31, 2013 while DD&A for the three and twelve months ended December 31, 2013 were $16.2 million (2012 - $Nil) and $34.8 million (2012 - $Nil), respectively.

The costs were generated from the Huntington and Trent & Tyne fields as discussed in *Key Projects, Production and Operations Update.* There was no cost of sales associated with operations in 2012 as Huntington commenced production on April 12, 2013, while all revenues from Trent & Tyne accrued into a restricted cash account between the economic date of the Trent & Tyne acquisition and the completion of the T6 well in January 2013.

OPERATING NETBACKS

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2013	**2012**	**2013**	**2012**
	$/boe	**$/boe**	**$/boe**	**$/boe**
Average Selling Price[1]	**103.84**	-	**97.63**	-
Operating Cost[2]	**(24.94)**	-	**(27.75)**	-
Netback from Operations	**78.90**	-	**69.88**	-

(1) Average Selling Price is inclusive of hedging
(2) Q3 operating costs had been understated by $2.1 million; this amount has been included in the Company's Q4 operating costs. Realized operating costs have been normalized. Operating costs for Q3 have not been restated.

Operating costs include all costs to produce and sell the commodity. Operating costs were consistent throughout the year ended December 31, 2013 averaging $27.75 per boe and $24.94 per boe in the quarter ended December 31, 2013. A certain percentage of operating costs at Huntington and Trent & Tyne are fixed. Management expects operating costs on a per boe basis to decrease as production continues to increase and stabilize at each field.

GENERAL AND ADMINISTRATIVE EXPENSES

		Three Months Ended December 31,	Three Months Ended December 31,	**Twelve Months Ended December 31,**		Twelve Months Ended December 31,
		2013	2012	**2013**		2012
Consulting fees / wages	$	**820**	**279**	**3,632**	$	1,391
Professional fees		**435**	**1,117**	**1,485**		1,677
Stock option expense		**981**	**1,292**	**3,896**		4,504
Depreciation		**8**	**9**	**37**		28
Insurance		**516**	**-**	**917**		-
Travel, office costs and other		**708**	**562**	**2,120**		1,167
Total	$	**3,468**	**3,259**	**12,087**	$	8,767
Per boe	$/boe	**11.76**	-	**18.01**		-

General and administrative costs were $3.5 million and $12.1 million respectively for the three and twelve months ended December 31, 2013. General and administrative costs for the year ended December 31, 2013 have increased from the comparative period of 2012 mainly as a result of increased consulting fees and wages, insurance and travel costs due to the Company's growth and increased operations. This was offset by a decrease in professional fees and stock option expense.

General and administrative costs increased from Q4 2012 to Q4 2013 mostly due to an increase in consulting fees and wages which is due to an increase in personnel driven by the increase in operations. This was offset by a decrease in professional fees in Q4 2012.

The stock option charge represents the fair value of the Company's stock options amortized over the respective vesting period via the graded vesting method. Pursuant to the plan, the Board of Directors determines the vesting provisions of the stock options at the date of grant. All of the options granted to date under the plan (other than options granted to a firm providing investor relations activities) vest as follows: ¼ immediately and ¼ vesting on the first, second and third anniversary dates. All unvested options vest upon the change of control of the Company. The options are non-transferable. The minimum exercise price is based on the trading price of the common shares on the date prior to the day of the grant less any applicable discount permitted by the TSX Venture Exchange. The future expense will vary as it is dependent on the number and vesting provisions of future stock option grants.

FOREIGN EXCHANGE

	2013	2012	% Change
Foreign exchange gain / (loss)	**$ 6,991**	$ (152)	4,699%

During the year ended December 31, 2013, the Company recognized a foreign exchange gain of $7.0 million (2012 – loss of $152,000). The exchange gain in 2013 arose primarily as a result of the strengthening of the GBP against the USD increasing the value of the GBP working capital balances held in Iona UK.

RELATED PARTY TRANSACTIONS

During the year ended December 31, 2013, the Company was charged $58,000 (2012 - $40,000) and $716,000 (2012 - $391,000), in legal fees for the three and twelve months ended December 31, 2013 respectively, of which $97,000 (2012 - $220,000) related to share issuance costs by a law firm where a director of the Company is a partner, of which $29,000 (2012 - $70,000) is included in accounts payable and accrued liabilities as at December 31, 2013.

Compensation of key management personnel

Key management personnel include all Directors, the Chief Executive Officer, and the Interim Chief Financial Officer. Compensation paid to and share-based compensation attributable to the key management personnel consists of the following:

	Year ended December 31, 2013	**Year ended December 31, 2012**
Short-term benefits	$ 2,239	$ 721
Share based payments [1]	2,344	2,495
Termination benefits	$ 71	$ -

[1] Represents amount of the non-cash share-based compensation expense estimated on grant date associated with share options (note 10). This amount may not be equal to the fair value ultimately received on exercise.

Included in accounts receivable is $117,483 (2012 - $265,000) due from a former officer and director of the Company who resigned from the Company's management team and Board. Of this amount $117,483 remains to be collected as at December 31, 2013. The amounts owing are non-interest bearing and secured. The Company expects full repayment of the remaining balances in 2014.

Except as disclosed, all related party transactions are in the normal course of operations and have been measured at the agreed to exchange amounts, which is the amount of consideration established and agreed to by the related parties and approximates fair value.

EXPLORATION AND EVALUATION

As at December 31, 2013 and as of the date of this MD&A no costs held within Exploration and Evaluation are considered to be impaired, however, the assets have not yet been determined to be technically feasible and commercially viable.

General exploration and evaluation

The Company had $22.0 million of additions during the year ended December 31, 2013 (2012 – $106.2 million) in addition to $14.5 million spent on acquiring an interest in exploration plays in the Huntington Field. The reduction in spending was mostly due to the purchase of the remaining working interest in Orlando and Kells from its joint venture partners.

The Company's exploration and evaluation expense in the income statement represents all pre-license costs and the capitalized costs from exploration and evaluation assets that have been expensed. These costs represent unrecoverable exploration and evaluation costs associated with an area and costs incurred prior to obtaining the legal rights to explore.

During the year ended December 31, 2013, the Company expensed $531,000 (2012 - $355,000) respectively of exploration and evaluation costs to the consolidated statement of operations and comprehensive loss. The additions to general exploration and evaluation within the statement of financial position mainly relates to development expenditure on both the Orlando and Kells fields and exploration values attributed to the exploration acreage acquired as part of the Huntington acquisition.

Property payments and disposals

On September 27, 2013, the Company satisfied all payments owed to Carrizo Oil & Gas Inc. for the Company's acquisition of its interest in the Huntington field.

On February 21, 2013, the Company completed the sale of a 25% working interest in its UK North Sea Orlando and Kells fields to Volantis Exploration for total gross proceeds of $36.8 million on close and pro-rata share of future staged payment obligations.

Drilling costs
On July 22, 2013, Iona UK resolved disputed historic drilling costs and received a cash payment of $3.6 million, which has been netted against additions in the year.

DEFERRED COSTS

Due to the business combinations as detailed in *Key Projects Update*, $38.5 million held in deferred costs in relation to Huntington and Trent & Tyne were transferred to property and equipment.

PROPERTY AND EQUIPMENT

Due to the business combinations as detailed in *Key Projects Update*, $38.5 million held in deferred costs in relation to Huntington and Trent & Tyne were transferred to property and equipment. Property plant and equipment increased by $330.3 million due to the Huntington and Trent & Tyne acquisitions. The remaining $5.8 million of additions mostly relate to costs spent on the Trent & Tyne fields.

Impairment

The Trent Field is located in Block 43/24a. There are three production wells of which two are currently active. Gas is exported to the Bacton terminal, 165 km to the south, via the Eagles Transportation System (ETS). The Tyne Field is located offshore in Block 44/18 of the Southern North Sea. Production is from gas-bearing reservoirs in the Carboniferous Ketch Formation at a depth of approximately 12,000 ft subsea. Four gas accumulations in four separate fault blocks have been drilled: Tyne North, Tyne South, Tyne West and Tyne East. A fifth fault block, Tyne North West, has not been drilled and is a possible exploration target. A total of eight exploration and appraisal wells have been drilled in the field as well as six production wells. Only three wells are currently producing: T2 in Tyne West, and T3A and T6 in

Tyne North. T6 was drilled in late 2012 as a replacement for T5, which has been shut since the year 2000. Gas is exported via a pipeline to the Trent field. As at December 31, 2013, Iona held a 20% interest in both the Trent and Tyne fields, with the remaining 80% being held by the Operator, Perenco.

Upon acquisition, the Company's T6 well, located in the Tyne North Field, which came on stream in early 2013, had originally used the production history for the T5 well as an analogue for the T6 well as the standoff perforations in the T6 well contact was about the same as in the T5 well when it was first drilled. During late 2013 and early 2014 the T6 well began experiencing technical difficulties and a gas water contact was detected in the T6 well. Therefore the Companies initial estimates for the T6 well have been refined based on analysis of the most recent production and pressure data. This along with a lower gas price index has resulted in indicators of impairment of the Company's Trent & Tyne assets.

In the fourth quarter of 2013, the Company recognized an impairment charge of $23.6 million with respect to these producing assets. The CGU was written down to the estimated recoverable amount based on fair value less cost of disposal. The estimated fair value was determined using future cash flows adjusted for risks specific to the asset and discounted using an before tax discount rate of 25%. The key assumptions in estimating the future cash flows for recoverable amounts are anticipated future commodity prices, expected production volumes and future operating and development costs. A 1% change in the discount rate would not significantly change the estimated recoverable amount.

GOODWILL

Huntington UK acquisition

Goodwill of $14.1 million was recorded on acquisition to the extent that the purchase cost exceeded the fair value of the identifiable assets and liabilities of Carrizo UK. Carrizo UK was a private company with interests in the Huntington field located in the United Kingdom continental shelf. None of the goodwill recognized is expected to be deductible for income tax purposes.

The Huntington UK purchase price allocation is preliminary in nature and will be reviewed in accordance with the provisions of IFRS 3 – Business Combinations within the specified twelve month period from completion date. The values allocated to Huntington Deep may be adjusted within the twelve month period and impact goodwill.

Trent & Tyne business combination accounting

The fair value of the identifiable assets and liabilities of Trent & Tyne exceeded the purchase cost and a profit on acquisition of $6.6 million has been recognized and recorded. The profit is a result of an increase in the fair value of the acquired reserves of Trent & Tyne from the time when the acquisition was negotiated to the acquisition date. The profit has been taken to the consolidated statement of operations and comprehensive loss.

SENIOR DEBT INSTRUMENTS

On September 27, 2013, Iona UK issued $275 million in senior secured bonds (the "Bonds"), net of discounts of $6.9 million and transaction cost of $8 million, for $260 million. As at December 31, 2013 the fair value of the Bonds were $275 million. The bonds mature on September 30, 2018. The Bonds carry an annual coupon rate of 9.5% payable semi-annually, were issued at 97.5% of par and are callable in whole or in part at the option of Iona UK at any time. Commencing 30 months after September 30, 2013, the Bonds will be repaid at 15% of the face value every six months with a 25% final payment at maturity. The Bonds contain certain early redemption options under which the Company has the option to redeem all or a portion of the Bonds at various redemption prices, which include the principal amount plus accrued and unpaid interest, if any, to the applicable redemption date. The Company reviewed the terms of the Bonds and determined that certain prepayment options were an embedded derivative. The fair value of the embedded derivative at inception was $1,146,000. At December 31, 2013 the derivative was valued at $262,000 and will be fair valued at each subsequent reporting period. The fair value of the derivative is the residual of the value of similar debt without the derivative less the current fair value of the bonds. The embedded derivative is presented separately from the bonds in statement of financial position as a current derivative instrument. At December 31, 2013 the balance of the Bonds of $262,450,000 represents the Bonds amortized cost net of transaction costs of $8 million and the initial fair value of the embedded derivative.

Payment date	Nominal installment amount	Premium on nominal installment
March 2016	**41,250,000**	**5%**
September 2016	**41,250,000**	**4%**
March 2017	**41,250,000**	**4%**
September 2017	**41,250,000**	**3%**
March 2018	**41,250,000**	**3%**
September 2018 (Maturity)	**68,750,000**	**2%**

On September 27, 2013, upon closing of the Bonds, the Company repaid the Company's Loan Facility in full. The carrying amount on the date of the Bond closure was $145.4 million, inclusive of waivers. Additionally, on September 27, 2013, the Company offset 3.1 million of the 7.4 million outstanding call options previously sold to Britannic Trading Limited, a subsidiary of BP Oil International Limited in February 2013, by purchasing 3.1 million call options effective between October 2014 and September 2016 (defined as the Tranche 1 Call Options under the Bond Agreement) for $33.5 million.

The Bonds are secured against the assets of the Company and its subsidiaries. Under the Bond Agreement, capital expenditures are limited to assets within the borrowing base (currently Huntington, Trent & Tyne, Orlando, Kells, Ronan and Oran). Under the Bond Agreement a working interest of at least fifty percent must be maintained in Orlando and Kells. Additionally no sale or disposal of any (direct or indirect) ownership interest in the Huntington Asset shall be permitted during the term of the Bonds as long as any call options are outstanding under the BP Structured Energy Derivative.

Under the Bond Agreement the Company must maintain the following financial covenants, as calculated quarterly:

- minimum liquidity (defined as the restricted group's cash and cash equivalents) of at least $30 million;
- a leverage ratio (defined as net interest bearing debt divided by twelve months of earnings before interest, taxes, depreciation and amortization ("EBITDA")) of not more than 3.0x; and
- ensure a minimum of both the capital employed ratio (defined as equity divided by the sum of equity and net interest bearing debt) and the restricted capital employed ratio (defined as restricted group equity divided by the sum of restricted group equity and net interest bearing debt) of 40% until December 31, 2016, and a minimum of 50% thereafter.

The restricted group is defined as Iona UK and Iona UK Huntington Ltd.

Under the Bond Agreement an event of default constitutes two consecutive quarterly covenant violations. The quarter ended December 31, 2013 is the first quarter that the Company is required to adhere to the financial covenants defined above.

The company was in breach of the leverage ratio at December 31, 2013 due to lower than expected sales from Huntington during the fourth quarter resulting from CATS restrictions and weather. Also impacting the Leverage Ratio was the $33.5 million retirement of Tranche 1 of the BP Call options, thereby lowering the Company's Cash and Cash Equivalents by $33.5 million, resulting in higher net interest bearing debt. This retirement was mandated by the Bond agreement.

At March 31, 2014, the Company is not in compliance with the leverage ratio covenant primarily due to the definition of cash and cash equivalents not including restricted cash accounts. The Company is currently in the process of amending the Bond Agreement to clarify the definition of cash and cash equivalents to include restricted cash accounts as originally intended. The amendment of the Bond Agreement contemplates the revision to the definition to be effective on the issue date of the Bond Agreement. Subsequent to the amendment the Company expects to be in compliance with all Bond covenants.

On April 16, 2014, the Company called a Bondholder Meeting to amend the definition of Cash and Cash Equivalents, as used in the Bond Agreement, to include the Bond proceeds escrowed specifically for the development of Orlando and Kells. A Bondholder vote is being held on May 6, 2014 and, upon the Bond Agreement being successfully amended, the Company expects to be in compliance with the Bond's financial covenants at March 31, 2014.

The table below delineates the Company's position with respect to the Bond covenants at December 31, 2013.

	31-Dec-13[(1)]	Covenant
Liquidity	$104,922	Greater than $30,000
Restricted Group Capital Employed Ratio	67%	Greater than 40%
Group Capital Employed Ratio	58%	Greater than 40%
Leverage Ratio	3.86	Not greater than 3.0x

(1) Includes restricted cash

DERIVATIVE INSTRUMENTS – COMMODITY HEDGING

The details of the hedging contracts entered into by the Company in the quarter are included in *Corporate Transactions.* The Company's derivative financial instruments measured at fair value as of December 31, 2013 are presented in the table below:

	Level 1	Level 2	Level 3	Total Fair Value
Current assets				
Derivative financial instrument assets (embedded derivative)	$ -	262	-	$ 262
Derivative financial instrument assets (put options)	-	31	-	31
Current liabilities				
Derivative financial instrument liabilities (call options)	-	16,867	-	16,867
Non-current liabilities				
Derivative financial instrument liabilities (call options)	$ -	31,038	-	$ 31,038

The table below presents the total loss on financial instruments that has been disclosed through the consolidated statement of comprehensive income:

	2013	2012
Cost of derivative options	$ 7,186	$ -
Unrealized (gain) / loss on commodity hedges	17,937	-
Realized (gain) / loss on commodity hedges	5,794	-
Total (gain)/ loss on commodity hedges	**$ 30,917**	$ -

TAXATION

Reconciliation of effective tax rate for the years ended December 31

	2013	2012
Loss before tax from continuing operations	**$ (65,461)**	$ (10,581)
Rate of corporation tax (parent)	**62.0%**	62.0%
	(40,585)	(6,560)
Small field allowance	**(20,862)**	-
Gain on acquisition	**(4,095)**	
Other permanent differences	**11,061**	710
Foreign tax rate difference	**2,104**	1,600
Change in unrecognized deferred tax asset	**(42,550)**	4,250
Tax expense / (recovery)	**$ (94,927)**	-

The ring-fence expenditure supplement is designed to assist companies that do not yet have sufficient taxable income for ring fence corporation tax purposes against which fully to set their exploration, appraisal and development costs. The ring-fence expenditure supplement increases the value of losses carried forward from one accounting period to the next by a compound 10% a year – 6% a year for accounting periods beginning before 1 January 2012 – for a maximum of 6 years.

The small field allowance provides an incentive for development of commercially marginal oil and gas fields that are under a certain size constraint. The small field allowance reduces the amount of adjusted ring fence profits on which the supplementary corporation tax of 32% is charged by a maximum possible of GBP 150 million.

Tax losses were recognized in the period to the extent that it is probable that future income will be available. These losses partially offset the deferred tax liability created on acquisition of Trent & Tyne and Huntington.

Reconciliation of Deferred Tax Liabilities

	2013	**2012**
Balance beginning of year	**$ -**	**$ -**
Deferred tax liability created on business combination	100,038	-
Deferred tax expense / (recovery)	(94,927)	-
Foreign exchange loss / (gain)	-	-
Ending deferred tax liability	**$ 5,111**	**-**

Unrecognized Deferred Tax Assets

Deferred tax assets have not been recognized in respect of the following items:

Year ended December 31, 2013

	United Kingdom	United States	Canada	Total
Other temporary differences	$ -	$ (315)	$ 1,480	$ 1,165
Tax losses	-	304	2,982	3,286
Total unrecognized deferred tax asset	**$ -**	**$ (11)**	**$ 4,462**	**$ 4,451**

Year ended December 31, 2012

	United Kingdom	United States	Canada	Total
Other temporary differences	$ 1,183	$ (315)	$ 2,064	$ 2,932
Tax losses	14,872	304	1,998	17,174
Total unrecognized deferred tax asset	$ 16,055	$ (11)	$ 4,062	$ 20,106

Movements of the Company's temporary differences for the year ended December 31, 2013 is as follows:

	31-Dec-12	Recognized in net income	Acquired in business combination	**31-Dec-13**
Tax loss carry forwards	(102,624)	(11,665)	(89,806)	**(204,095)**
Property and equipment	103,301	(59,840)	195,572	**239,033**
Decommissioning	(654)	(2,618)	(5,696)	**(8,968)**
Other	(23)	57	(32)	**2**
Change in unrecognized deferred tax asset	-	(20,861)	-	**(20,861)**
	-	(94,927)	100,038	**5,111**

A deferred tax asset has not been recognized as it is not probable at the year end that the asset is recoverable. The asset is recoverable if there are future suitable taxable profits from which the future reversal of the underlying temporary differences can be deducted. It is likely that with further development of the assets in the United Kingdom that a deferred tax asset will be recognized. The probability of recoverability will be reviewed at the end of each reporting period.

The Company has incurred cumulative non-capital losses at December 31, 2013 of approximately $11,928,000 (December 31, 2012 - $6,365,000) for Canadian income tax purposes, which are available to reduce taxable income in future years. If not utilized, these losses will expire in the years ending December 31, 2026 to 2032. The unrecognized UK deferred tax asset relates to pre-trading expenditure which if capital in nature can be carried on indefinitely. Currently all pre-trading expenditure in the UK is considered capital in nature.

COMMITMENTS

In addition to the amounts recorded in the condensed consolidated financial statements, based on management's best estimate, the Company has the following contractual obligations:

	December 31, 2013				
	Payments Due in Period				
Contractual Obligations	**Total**	**Less than 1 Year**	**1 to 3 Years**	**3 to 5 Years**	**More than 5 Years**
U.S. Segment					
Exploration leases	**$ 204**	17	51	51	$ 85
UK Segment					
Office lease	**130**	87	43	-	-
Drilling, completion, facility construction	**17,465**	17,465	-	-	-
Total UK Segment	**17,595**	17,552	43	-	-
Corporate Segment					
Office lease	**15**	15	-	-	-
Total Contractual Obligations	**$ 17,814**	17,584	94	51	$ 85

The above table does not include contingent property payments with respect to the Orlando property due pursuant to property acquisition agreements.

LIQUIDITY AND CAPITAL RESOURCES

The Company manages its capital with the prime objectives of safeguarding the business as a going concern, creating investor confidence, maximizing long-term returns and maintaining an optimal structure to meet its financial commitments and to strengthen its working capital position. At present, the capital structure of the Company is primarily composed of shareholders' equity. The Company's strategy is to access capital, primarily through equity issuances, reserve based lending, and other alternative forms of debt financing. The Company actively manages its capital structure and makes adjustments relative to changes in economic conditions and the Company's risk profile.

Cashflow from operations
Cash generated from operating activities, funds flow, was $31.3 million primarily due to cash generated from the Huntington oil field and the Trent & Tyne gas field.

Cashflow from financing activities
Cash generated from financing activities was $229.4 million primarily due to Iona's issuance of a $275 million senior secured bond.

Cashflow from investing activities
Cash used in investing activities was $240.0 million primarily due to capital expenditure on the acquisition of the Orlando interest and the purchase of the Huntington oil field.

The Company continues to be fully funded, with more than sufficient financial resources to cover its anticipated future commitments from its existing cash balance and forecast cash flow from operations. No unusual trends or fluctuations are expected outside the ordinary course of business.

As at December 31, 2013, the Company has net assets of $192.2 million, working capital of $79.1 million and $17.6 million of commitments due in the next twelve months.

Under the senior secured bonds, capital expenditures are limited to assets within the borrowing base (currently Huntington, Trent & Tyne, Orlando, Kells and Ronan & Oran). Allowable capital expenditures include: a) all cash calls by the Operators; b) all capital costs; c) all costs of producing, lifting, transporting, storing, processing and selling associated hydrocarbons; d) all costs of reinstating damaged facilities; e) all costs of satisfying any liability in respect of seepage, pollution and well control; f) all insurance premiums and all the fees, costs and expenses; g) all exploration and appraisal expenditures; h) all costs of abandonment, and any payments to make provision for abandonment costs; i) all royalties and other amounts payable under any Petroleum production license; j) all general and administrative expenditures; k) loan repayments and finance costs; and l) any other costs, expenses or payments as agreed to by the Lenders.

FINANCIAL RISKS

Crude oil and natural gas operations involve certain risks and uncertainties. These risks include, but are not limited to, commodity prices, foreign exchange rates, credit, operational and safety.

Operational risks are managed through a comprehensive insurance program designed to protect the Company from significant losses arising from risk exposures. Risks associated with commodity prices, interest and exchange rates are generally beyond the control of the Company; however, various hedging products may be considered to reduce the volatility in these areas.

Safety and environmental risks are addressed by compliance with government regulations as well as adoption and compliance of the Company's safety and environmental standards policy.

The Company will be exposed to concentration of credit risk as substantially all of the Company's accounts receivable will be with joint venture partners in the oil and gas industry and are subject to normal industry credit risks. The Company mitigates this risk by entering into transactions with long-standing, reputable counterparts and partners. If significant amounts of capital are to be spent on behalf of a joint venture partner, the partner is "cash called" in advance of the capital spending taking place.

All derivative instruments are recorded in the balance sheet at fair value unless they qualify for the expected purchase, sale and usage exemption. All changes in their fair value are recorded in income unless cash flow hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income until the hedged transaction is recognized in net earnings.

The Company operates on an international basis and therefore foreign exchange risk exposures arise from transactions denominated in currency other than the United States Dollar. The Company is exposed to foreign currency fluctuations as it holds cash and incurs expenditures in property and equipment in foreign currencies. The Company incurs expenditures in Pound sterling, Euros, United States dollars and Canadian dollars and is exposed to fluctuations in exchange rates in these currencies. There are no exchange rate contracts in place as at or during the period ended December 31, 2013, or thereafter.

Assuming all other variables remain constant, a 1% increase or decrease in foreign exchange rates on the foreign cash and restricted cash balances at December 31, 2013 would have impacted the comprehensive loss of the Company for the year ended December 31, 2013 by $21,000 (December 31, 2012 – $507,000).

In addition at December 31, 2013, the Company held $11,629,030 (£7,035,957) (2012 $54,963,000 (£33,991,000)) of accounts payable in Pound Sterling. Assuming all other variables remain constant, a 1% increase or decrease in foreign exchange rates at December 31, 2013 would impact the comprehensive loss of the Company for the year ended December 31, 2013 by $116,290 (December 31, 2012 - $550,000).

OUTSTANDING SHARE DATA

The Company has authorized an unlimited number of Common shares, without nominal or par value and unlimited number of preferred shares, issuable in series. The Company, as at the date of this MD&A had 366,830,868 Common Shares, and 34,750,000 stock options outstanding.

The following details the stock option structure as of the date of this MD&A:

Date of Grant	Number Outstanding	Exercise Price CAD$	Weighted Average Remaining Contractual Life	Date of Expiry	Number Exercisable Dec 31, 2012
May 31, 2011	9,550,000	$0.60	1.42 years	May 31, 2015	7,162,500
November 25, 2011	100,000	$0.60	1.90 years	November 25, 2015	75,000
April 13, 2012	16,220,000	$0.57	3.28 years	April 12, 2017	8,110,000
January 10, 2013	175,000	$0.59	4.03 years	January 10, 2018	175,000
March 5, 2013	6,780,000	$0.63	4.18 years	March 5, 2018	1,695,000
July 29, 2013	700,000	$0.59	4.58 years	July 29, 2018	175,000
October 3, 2013	625,000	$0.63	4.76 years	October 3, 2018	625,000
October 23, 2013	600,000	$0.63	4.81 years	October 23, 2018	150,000
	34,750,000				18,167,500

On February 21, 2013 the Company issued 41,818,603 common shares pursuant to a public offering at a price of CAD$0.55 per share for gross proceeds of CAD$23,000,232. On April 11, 2012 the Company issued 184,044,400 common shares pursuant to a public offering at a price of CAD$0.50 per share for gross proceed of CAD$92,022,200.

On March 13, 2013 and August 2, 2013 the Company had 87,300 and 20,000 warrants exercised, respectively, for gross proceeds of $22,921. The warrants were issued to brokers who assisted with the Company's private placements in 2010. The warrants were exercisable into a common share of the Company at a strike price of CAD$0.22 per warrant, in August 2013, the 112,800 outstanding warrants expired. The warrants were valued at $28,000 using the Black Scholes option pricing model, recorded as a share issuance costs with the following assumptions: dividend yield – Nil, expected volatility 75%, risk free rate of return 1.53%, weighted average life – 3 years, forfeiture rate – Nil.

SUMMARY OF QUARTERLY RESULTS

($ thousands, except per share amounts)

	2013				2012			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue	**$33,797**	18,082	11,771	$1,858	$ -	-	-	$ -
Average Daily Production (boepd)								
Crude oil [(1)]	**2,320**	1,614	1,058	-	-	-	-	-
Natural Gas	**765**	837	656	316	-	-	-	-
Total	**3,085**	2,451	1,714	316	-	-	-	-
Net income / (loss)	**31,553**	899	9,188	(12,174)	(4,456)	(2,258)	(2,854)	(1,024)
Income / (loss) per share – basic	**0.09**	0.00	0.02	(0.03)	(0.01)	0.01	0.01	0.01
Income / (loss) per share – diluted	**0.09**	0.00	0.02	(0.03)	(0.01)	0.01	0.01	0.01
Funds Flow	**28,225**	11,397	1,364	(9,662)	(1,649)	(1,448)	(797)	(659)
Funds Flow per share – basic	**0.08**	0.03	0.00	(0.02)	(0.01)	(0.00)	(0.00)	(0.00)
Funds Flow per share – diluted	**0.08**	0.03	0.00	(0.02)	(0.01)	(0.00)	(0.00)	(0.00)
Adjusted EBITDA	**27,936**	12,737	3,230	3,053	(4,499)	(2,321)	(2,910)	(1,008)
Adjusted EBITDA per share – basic	**0.08**	0.03	0.01	0.01	(0.01)	(0.01)	(0.01)	(0.01)
Adjusted EBITDA per share – diluted	**0.08**	0.03	0.01	0.01	(0.01)	(0.01)	(0.01)	(0.01)
Working capital surplus/ (deficit)	**79,075**	71,247	(155,367)	(47,275)	(34,897)	40,863	70,177	4,945
Total assets	**$545,079**	631,690	516,606	$ 513,002	$204,566	182,253	164,192	$76,045
Weighted average common shares - basic	**360,849**	366,824	377,060	342,597	324,905	324,905	302,647	140,861
Weighted average common shares– fully diluted	**363,078**	366,824	377,060	342,597	324,905	324,905	302,647	140,861

(1) Adjusted for start of production for Huntington on April 12, 2013

Comparative information has been restated to reflect the change in presentation currency from Canadian to US Dollar using the average rate in each respective quarter.

Over the past eight quarters, the Company's oil and gas sales have generally increased due to a successful drilling program and two business combinations. Fluctuations in production and the Brent benchmark price have also contributed to the fluctuations in oil and gas sales.

Net income has fluctuated primarily due to changes in funds flow from operations, unrealized derivative gains and losses, which fluctuate with the changes in forward market prices, along with associated fluctuations in the deferred tax expense (recovery).

CRITICAL ACCOUNTING ESTIMATES

The Company's management made judgements, assumptions and estimates in the preparation of the financial statements. Actual results may differ from those estimates. The accounting policies applied by the Company are described in Note 3 of the audited consolidated financials statements as at and for the year-ended December 31, 2013.

The preparation of financial statements requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the year. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future periods could require a material change in the financial statements. Accordingly, actual results may differ from the estimated amounts as future confirming events occur. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are as follows:

The operations of the Company are complex, and regulations and legislation affecting the Company are continually changing.

The financial statements include accruals based on the terms of existing joint venture agreements. Due to varying interpretations of the definition of terms in these agreements the accruals made by management in this regard may be different from those determined by the Corporation's joint venture partners. The effect on the consolidated financial statements resulting from such adjustments, if any, will be reflected prospectively.

The Company's operations change significantly each reporting period, this change can impact the functional currencies of the Company and its subsidiaries. Management makes judgements each reporting period as to the appropriateness of the existing functional currencies and makes changes when the facts and circumstances warrants. These changes could have material impact on the consolidated financial statements in future periods.

Amounts that will be recorded for depletion and depreciation and amounts used for impairment calculations are based on estimates of petroleum and natural gas reserves. By their nature, the estimates of reserves, including the estimates of future prices, costs, discount rates and the related future cash flows, are subject to measurement uncertainty. Accordingly, the impact to the consolidated financial statements in future periods could be material.

Oil and natural gas assets are aggregated into cash-generating units based on their ability to generate largely independent cash flows and are used for impairment testing. The determination of the Company's cash-generating units is subject to Management's judgment.

The decision to transfer assets from exploration and evaluation to property, plant and equipment is based on the estimated recoverable reserves used in the determination of an area's technical feasibility and commercial viability. As such there is judgment in determining the timing of these transfers.

Compensation costs recognized for share based compensation plans are subject to the estimation of what the ultimate payout will be using pricing models such as the Black-Scholes model which is based on significant assumptions such as volatility, dividend yield and expected term. These are recognized over the vesting term and the underlying options.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company operates are subject to change. As such income taxes are subject to measurement uncertainty.

Deferred income tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings.

CHANGE IN FUNCTIONAL AND PRESENTATION CURRENCY

These consolidated financial statements are presented in United States dollars ("US dollars"). The functional currency of Iona Energy Inc. is Canadian dollars. The functional currencies of the Company's foreign subsidiaries are US dollars. The Company changed the functional currency of Iona Energy Company (UK) Limited ("Iona UK") from Pounds Sterling to US dollars with effect from October 1, 2013. This change was triggered by the commencement of oil and gas production and the issuance of $275 million of US denominated debt by Iona UK. The statement of financial position of Iona UK was translated to US dollars at the October 1, 2013 rate of 1.6204 GBP per 1 USD. Transactions impacting the statement of operations and comprehensive income were translated to US dollar using rates which approximate the rates at the date of transaction. The resulting gains and losses were recorded in the statement of comprehensive income.

In 2013, the Company changed its presentation currency from the Canadian dollars (“CAD”) to the US dollar. These consolidated financial statements are presented in US dollars, which is the Company’s presentation currency. The change in presentation currency is to better reflect the Company’s business activities and to improve investors’ ability to compare the Company’s financial results with other publicly traded businesses in the oil and gas industry. In making this change to the US dollar presentation currency, the Company followed the guidance in IAS 21 The Effects of Changes in Foreign Exchange Rates and have applied the change retrospectively as if the new presentation currency had always been the Company’s presentation currency. In accordance with IAS 21, the financial statements for all years and periods presented have been translated to the new US dollar presentation currency. For the 2012 comparative balances, assets and liabilities have been translated into the presentation currency (US dollars) at the rate of exchange prevailing at the reporting date. The statements of comprehensive income (loss) were translated at the average exchange rates for the reporting period, or at the exchange rates prevailing at the date of transactions. Exchange differences arising on translation were taken to the foreign currency translation reserve in shareholders’ equity. The Company has presented a third statement of financial position as at January 1, 2012 without the related notes except for the disclosure requirements outlined in IAS 8 accounting policies, changes in accounting estimates and errors. The resulting effect of the change in presentation currency of $158,000 on the comparative figures is reflected in the accumulated other comprehensive income at December 31, 2012.

ACCOUNTING POLICY CHANGES

Changes in accounting policies
Effective January 1, 2013, the Company adopted IFRS 10 “Consolidated Financial Statements”, IFRS 11 “Joint Arrangements, IFRS 12 “Disclosure of Interests in Other Entities”, and the amendments to IAS 28 “Investments in Associates and Joint Ventures.”

There were no changes to the consolidated financial statements or the consolidation process as a result of adoption of IFRS 10. IFRS 11 classifies interests in joint arrangements as joint ventures or joint operations depending on the rights and obligations of the parties in the arrangement. The Company performed a review of interests in joint arrangements and concluded that shared wells operate as joint operations and accordingly there is no change in the accounting for these assets as a result of adoption of this standard. As a result, there were no changes as a result of the adoption of IFRS 12 as well. Furthermore the Company was also required to adopt IFRS 13 “Fair Value Measurements,” amendments to IAS 1 “Presentation of Financial Statements,” amendments to IFRS 7 “Financial Instruments: Disclosures.” There were no material changes as a result of the adoption of these standards.

On 1 October 2013 the Company changed its presentation currency to US dollars. Comparative figures have been restated to US dollars, the resulting effect of the change in presentation currency of $158,000 on the comparative figures is reflected in the accumulated other comprehensive income at December 31, 2012.

Future Changes in Accounting Policies:
Iona has reviewed new and revised accounting pronouncements that have been issued but are not yet effective. The Company is currently evaluating the impact of the adoption of these standards and amendments. The adoption of these standards and amendments are not expected to significantly impact the Company.

In May 2013, the IASB issued amendments to IAS 36 "Impairment of Assets" which reduce the circumstances in which the recoverable amount of CGUs is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. The amendments are required to be adopted retrospectively for fiscal years beginning January 1, 2014, with earlier adoption permitted. These amendments will be applied by Iona on January 1, 2014 and the adoption will only impact Iona's disclosures in the notes to the financial statements in periods when an impairment loss or impairment reversal is recognized.

In May 2013, the IASB issued IFRIC 21 "Levies," which was developed by the IFRS Interpretations Committee ("IFRIC"). IFRIC 21 clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. The interpretation also clarifies that no liability should be recognized before the specified minimum threshold to trigger that levy is reached. IFRIC 21 is required to be adopted retrospectively for fiscal years beginning January 1, 2014, with earlier adoption permitted. IFRIC 21 will be applied by Iona on January 1, 2014 and the adoption is not expected to have a material impact on Iona’s consolidated financial statements.

The IASB has undertaken a three-phase project to replace IAS 39 "Financial Instruments: Recognition and Measurement" with IFRS 9 "Financial Instruments." In November 2009, the IASB issued the first phase of IFRS 9, which details the classification and measurement requirements for financial assets. Requirements for financial liabilities were added to the standard in October 2010. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

RISKS AND UNCERTAINTIES

Management defines risk as the evaluation of probability that an event might happen in the future that could negatively affect the financial condition and/or results of operations of Iona. The following section describes specific and general risks that could affect the Company. The following descriptions of risk do not include all possible risks, as there may be other risks of which management is currently unaware. Moreover, the likelihood that a risk will occur or the nature and extent of its consequences if it does occur, are not possible to predict with certainty, and the actual effect of any risk or its consequences on the business could be materially different from those described below.

Reliance on Third Parties
To the extent Iona is not the operator of its oil and natural gas properties, Iona will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators including the operators with respect to the Huntington and Trent & Tyne properties.

Foreign Operations
Presently, all of Iona's oil and gas operations and assets are located in foreign jurisdictions. As a result, Iona is subject to political, economic and other uncertainties, including but not limited to changes, sometimes frequent and applied retroactively, in energy policies or the personnel administering them, nationalization, expropriation of property without fair compensation, cancellation or modification of contract rights, foreign exchange restrictions, currency fluctuations, royalty and tax increases, and other risks arising out of foreign governmental sovereignty over the areas in which Iona's operations are conducted, as well as risks of loss due to civil strife, acts of war, guerilla activities and insurrections. Changes in legislation may affect Iona's oil and natural gas exploration and production activities. Iona's international operations may also be adversely affected by laws and policies of Canada as they pertain to foreign trade, taxation and investment.

Iona's subsidiary, Iona UK, was incorporated under the laws of Scotland. In addition, substantially all of Iona's oil and gas assets are located in the U.K. North Sea. The government of Scotland has proposed terms upon which Scotland could secede from the United Kingdom. If all required governmental approvals are obtained and such proposal for secession is implemented, Iona may be subject to substantial changes in legislation, including taxation and environmental legislation. The effect upon Iona of any such proposed changes being implemented is uncertain at this time.

In the event of a dispute arising in connection with its foreign operations, Iona may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of courts in Canada or enforcing Canadian judgments in foreign jurisdictions. In addition, Iona's existing joint ventures and its subsidiaries were formed pursuant to, and their operations are governed by, a number of complex legal and contractual relationships. The effectiveness of and enforcement of such contracts and relationships with parties in these jurisdictions cannot be assured. Consequently, Iona's foreign exploration, development and production activities could be substantially affected by factors beyond Iona's control, any of which could have a material adverse effect on Iona.

Production Concentration
The Company's anticipated revenue for 2013 and 2014 is dependent upon production rates from the Company's Huntington and the Trent & Tyne fields as well as prevailing oil and natural gas prices in the UK marketplace. The Company is dependent upon revenue from these fields to service future obligations, including future obligations relating to the Bonds. The Company's current production is concentrated to a limited number of wells which are tied back to two production platforms (one for Huntington production and one for Trent & Tyne production). A decrease in production from the Huntington field or the Trent & Tyne field for any reason, including if the actual reserves associated with such fields are lower than the Company's estimated reserves for such fields, could have an adverse impact on the Company's operating results, financial position or ability to service its obligations. Additionally, issues at either of the two production platforms which constrain, delay or limit production, including without limitation, unanticipated delays, shutdowns, mechanical problems, extreme weather conditions or production curtailments by the facility operators, could also have an adverse impact on the Company's operating results, financial position or ability to service its obligations.

Financing Requirements and Liquidity

It may take many years and substantial cash expenditures to pursue exploration activities on Iona's existing undeveloped properties. Accordingly, Iona is likely to need to raise additional funds from outside sources in order to explore and develop its properties in a timely manner. Additionally, unexpected delays may result in significant increases in the capital expenditures required to develop projects.

Iona's financing risk relates to the availability and cost of equity or debt financing and is affected by many factors, including world and regional economic conditions, the state of international relations, the stability and the legal, regulatory, fiscal and tax policies of various governments in areas of operation, fluctuations in the world and regional price of oil and gas and in interest rates, the outlook for the oil and gas industry in general and in areas in which Iona has or intends to have operations, and competition for funds from possible alternative investment projects. Although there have been improvements in the global economy and financial markets in recent months, there continues to be restrictions on the availability of credit which may limit Iona's ability to access debt or equity financing for its development projects.

Potential investors and lenders will be influenced by their evaluations of Iona and its projects, including their technical difficulty, and comparison with available alternative investment opportunities.

Iona continuously monitors its cash position, capital commitments and future capital requirements in order to ensure sufficient liquidity and capital resources are available. In the event that adequate funds from credit/loan facilities, suitable aligned partners or cashflows are not attained; Iona may be required to scale back certain projects or to raise additional funds.

Iona is also dependent upon continued access to the proceeds of the Bond offering to fund its development projects. An inability to access the proceeds of the Bond offering for any reason, including non-compliance with the operating covenants contained in the Bond Agreement may have a material adverse effect on Iona and its operations.

Loss from Operations
Iona had retained earnings as at December 31, 2013 of $12,733,000 and a deficit $16,733,000 as at December 31, 2012. No assurance can be given that Iona will not experience operating losses or write-downs of its oil and gas properties in the future.

Volatility of Crude Oil and Natural Gas Prices
Crude oil and natural gas are commodities that are sensitive to numerous worldwide factors, which are beyond Iona's control, and are generally sold at contract or posted prices. Changes in world crude oil and natural gas prices may significantly affect Iona's results of operations and cash generated from operating activities. Consequently, such prices may also affect the value of Iona's oil and gas properties and the level of spending for oil and natural gas exploration and development.

Iona's crude oil prices are based on various reference prices, primarily the WTI crude oil reference price and other reference prices such as UK Brent Light. Occasionally a differential in price exists between WTI and UK Brent Light. Adjustments are made to the reference price to reflect quality differentials and transportation. WTI and other reference prices are affected by numerous and complex worldwide factors such as supply and demand fundamentals, economic outlooks, production quotas set by the Organization of Petroleum Exporting Countries ("OPEC") and political events. Occasionally quality differentials are affected by local supply and demand factors.

Any material declines in prices could result in a reduction of Iona's net production revenue. The economies of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of Iona's reserves and Iona limiting or abandoning an exploration program on its undeveloped properties. Iona might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Iona's net production revenue. All of Iona's expenditures are subject to the effects of inflation and prices received for the product sold are not readily adjustable to cover any increase in expenses from inflation.

Hedging
From time to time the Company may enter into agreements such as the Payment Swap and the hedging agreements entered into with the lenders in the Loan Facility to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases and the Company may nevertheless be obligated to pay royalties on such higher prices, even though such higher prices are not received by it, after giving effect to such agreements.

Offshore Exploration

Iona faces additional risks when conducting offshore activities. In particular, drilling conditions, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity, or other geological and mechanical conditions. Sub-sea tiebacks in the UK North Sea, while common, are also affected by weather conditions. Potential pipeline tie-backs can only be conducted from April to late September. Offshore oil and gas activities can also be affected by extreme weather and ocean phenomena arising from occurrences such as hurricanes and tsunamis. Due to general industry response to the BP Macondo Gulf of Mexico, it may be that extra delays in permitting and increased costs with respect to insured operations, oil spill mitigation and clean up will be incurred.

Availability of Drilling Equipment and Access Restrictions
Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Iona and may delay exploration and development activities. Iona is subject to the relatively limited availability of offshore drilling rigs to proceed with its UK North Sea drilling program.

Access to Production Facilities and Pipelines
Access to facilities and pipelines to process field production is an important consideration when developing fields in the North Sea. Such access is not guaranteed and directly affects the economics of a project. The United Kingdom government with the assistance of DECC has introduced a policy which has been adopted by the major operators of facilities in the North Sea that should allow access to facilities at a reasonable rate.

These types of initiatives are intended to ensure that reserves that cannot support facilities on a stand-alone basis can be developed.

Conflicting Interests with Partners
Joint venture, acquisition, financing and other agreements and arrangements must be negotiated with independent third parties and, in some cases, must be approved by governmental agencies. These third parties generally have objectives and interests that may not coincide with Iona's interests and may conflict with Iona's interests. Unless the parties are able to compromise these conflicting objectives and interests in a mutually acceptable manner, agreements and arrangements with these third parties will not be consummated.

In certain circumstances, the concurrence of co-venturers may be required for various actions. Other parties influencing the timing of events may have priorities that differ from Iona's, even if they generally share Iona's objectives. Demands by or expectations of governments, co-venturers, customers, and others may affect Iona's strategy regarding the various projects. Failure to meet such demands or expectations could adversely affect Iona's participation in such projects or its ability to obtain or maintain necessary licences and other approvals.

Changes to Development Plans
Development plans for the Company's properties are based on management's estimates as of the date of this MD&A. Development plans may change as a result of new information, events or as a result of business decisions. Any such changes could have a material effect on the Company's proposed capital expenditures and the timelines associated with the development of the Company's properties.

Foreign Currency Rate Risk
A significant portion of Iona's activities is transacted in or referenced to United States dollars, Canadian dollars or British Pounds Sterling. Iona's operating costs and certain of Iona's payments, in order to maintain property interests, is incurred in the local currency of the jurisdiction where the applicable property is located. As a result, fluctuations in the Canadian dollar and British pounds sterling against the United States dollar, and each of those currencies against any other local currencies in jurisdictions where properties of Iona are located, could result in unanticipated fluctuations in Iona's financial results which are denominated in US dollars. Iona has not entered into any risk management contracts to hedge its exposure to foreign exchange rates.

Commodity Price Risk
From time to time Iona may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Iona would not benefit from such increases.

Governmental Regulation
The petroleum industry is subject to regulation and intervention by governments in such matters as the awarding of

exploration and production interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights. As well, governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for natural gas and crude oil, increase costs and may have a material adverse impact on Iona. Export sales are subject to the authorization of provincial and federal government agencies and the corresponding governmental policies of foreign countries. Development of reserves and rates of return are also susceptible to changes in national fiscal policy.

The UK government does not assess a crown royalty against production. The current tax regime in the UK is favorable to companies of the Iona's size in that it allows full deductions of appraisal and development expense before any tax is payable. As of January 1, 2006, the supplementary tax rate applicable to North Sea oil and gas companies rose from 10% to 20%. This change resulted in an effective rate of corporation tax of 30% of profits after all capital and operating costs have been recovered, and an effective supplementary rate of 20% on profits after all capital and operating costs (excluding finance costs) have been recovered, resulting in an effective combined base and supplementary tax rate of no less than 50%. In 2009, a number of reforms were introduced to the North Sea fiscal regime aimed at fostering developments in smaller fields as well as more complex high pressure/high temperature and heavy oil fields. The smaller field relief is granted in respect of fields less than 20 MMbbls and is a potential benefit to Iona. Further favorable tax reforms were announced in January 2010 in which the additional tax allowances were extended to gas fields in frontier areas.

On March 24, 2011, the supplementary tax rate applicable to North Sea oil and gas companies increased unexpectedly from 20% to 32%. As a result, the effective combined base and supplementary tax rate rose from 50% to 62%.

On March 21, 2012, the UK Government increased the Small Field Allowance (“SFA”) tax shelter availability from the 32% Supplemental tax charge for small developments. The size of fields that qualify for full SFA was increased to include all fields with reserves of under 45 MMboe and the tax allowance available to each field has been doubled from approximately $120 million to $240 million. The expectation is that this change will materially reduce the future effective tax rate of the Company.

During September 2012, the UK Government announced the Brown Field Allowance (“BFA”), which is a new tax relief to encourage investment in older oil and gas fields. The BFA will shield up to £250m of income in qualifying brown field projects, or £500m for projects in fields paying Petroleum Revenue Tax, from the 32% Supplementary Charge rate (providing tax relief of up to £80m or £160m respectively). The level of relief available to an individual project will depend on its size and unit costs. A qualifying project will be an incremental project increasing expected production from an offshore oil or gas field as described in a revised consent for development which is authorized by DECC on or after September 7, 2012, and has verified expected capital costs per tonne of incremental reserves in excess of £60. The maximum level of allowance will be £50/tonne and will be available to projects with verified expected capital costs of £80/tonne or above. The Company welcomes this announcement and hopes to utilize it on its qualifying projects in the future.

Based on Iona's present stage of development, Iona is able to avail itself of tax efficiencies with respect to tax pools and small field allowances and therefore expects the supplementary tax rate changes to have a small but negative effect on the present net worth of Iona's reserves. Any further changes to these laws would impact the net present worth of Iona's reserves. No assurances can be given that such an event would not re-occur.

Strategic Partnerships
As part of its development plan in the North Sea, Iona may consider the formation of strategic partnerships, potentially sharing development costs and, where appropriate, the acquisition or exchange of working interests. There is no assurance that any such strategic transaction will be entered into. If such strategic transaction is entered into, there is no assurance that such transaction will be successful.

Write-Off of Unsuccessful Properties and Projects
In order to realize the carrying value of its oil and gas properties and ventures, Iona must produce oil and gas in sufficient quantities and then sell such oil and gas at sufficient prices to produce a profit. Iona has a number of non-producing oil and gas properties. The risks associated with successfully developing such oil and gas properties are even greater than those associated with successfully continuing development of producing oil and gas properties, since the existence and extent of commercial quantities of oil and gas in unevaluated properties have not been fully established. Iona could be required to write-off some or all of its non-producing oil and gas properties if such projects prove to be unsuccessful.

Insurance
Iona's operations are subject to the risks normally associated with the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, blowouts, cratering and fires, all of which could result in personal injuries, loss of life and damage to the property of Iona and others. In accordance with customary industry practice, Iona is not fully insured against all of these risks, nor are all such risks insurable. Damages and losses occurring as a result of such risks may give rise to claims against Iona.

Although Iona believes that it, or where applicable the operator, will carry adequate insurance with respect to its operations in accordance with industry practice, in certain circumstances Iona's, or where applicable the operator's, insurance may not cover or be adequate to cover the consequences of such events. The payment of such uninsured liabilities would reduce the funds available to Iona. The occurrence of a significant event that is not covered or not fully covered by insurance, or the insolvency of the insurer of such event, could have a materially adverse effect on the business, financial condition and results of operations of Iona. Moreover, there can be no assurance that Iona will be able to maintain adequate insurance in the future at rates that it considers reasonable.

Regulatory Approvals
The further development of Iona's properties requires the approval of applicable regulatory authorities to the plans of Iona with respect to the drilling and development of such properties. A failure to obtain such approval on a timely basis or material conditions imposed by such authority in connection with the approval would materially affect the prospects of Iona.

Dilution from Further Equity Issuances
If Iona issues additional equity securities to raise additional funding or as consideration for the acquisition of a company or assets, as the case may be, such transactions may substantially dilute the interests of Iona Shareholders, and reduce the value of their respective investment.

Dividends
The Company has neither declared nor paid any dividends on its Ordinary Shares since the date of its incorporation. Any payments of dividends on the Ordinary Shares of the Company will be dependent upon the financial requirements of the Company to finance future growth, the financial condition of the Company and other factors, which the Company's board of directors may consider appropriate in the circumstance. It is unlikely that the Company will pay dividends in the immediate or foreseeable future.

For additional information regarding the Company's risks and uncertainties, please refer to the Company's annual information form for the year ended December 31, 2012, which is available on SEDAR under the Company's profile at www.sedar.com.

Notes Regarding Oil and Gas Disclosure
As used in this MD&A, "boe" means barrel of oil equivalent on the basis of 6 mcf of natural gas to 1 bbl of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

It should not be assumed that the present worth of estimated future net revenue represents the fair market value of the reserves disclosed in this MD&A. The reserve and related revenue estimates set forth in this MD&A are estimates only and the actual reserves and realized revenue may be greater or less than those calculated. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

As used in this MD&A, "possible reserves" are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Additionally, this MD&A uses certain abbreviations as follows:

Oil and Natural Gas Liquids		Natural Gas	
bbls	barrels	mcf	thousand cubic feet
Mbbls	thousand barrels	mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf	millions of cubic feet
MMboe	million barrels of oil equivalent	MMcf/d	millions of cubic feet per day
boepd	barrels of oil equivalent per day	Bscf	billion standard cubic feet
bopd	barrels of oil per day		
NGLs	natural gas liquids		

Additional information relating to the Company is available on SEDAR at www.sedar.com.