EXECUTIVE SUMMARY

Iona Energy Inc. (TSX-V: INA) announces its financial and operating results for the year ended December 31, 2014 and details of its end of 2014 reserves assessment.

2014 Highlights

Operating

- 2014 average net production of 2,229 barrels of oil equivalent per day ("boepd") driven by low availability of the Central Area Transmission System ("CATS") gas export system for Huntington.
  - Huntington 2014 average production of 13,472 boepd (gross), 2,021 boepd (net to the Company's 15% working interest[(1)]).
  - Trent & Tyne 2014 average production of 1,043 boepd (gross), 209 boepd (net to the Company's 20% working interest).
- New executive team completed during Q4 2014.
- Orlando development remains on track for first production in Q4 2016.
  - Full suite of offtake agreements executed with CNR International (UK) Limited ("CNR") during Q4 2014.
  - Management seeking to deliver capex savings of 10-15% on the current 2015-2016 budget of US$215 million (gross).
- 29.2 million barrels of oil equivalent ("mmboe") proved and probable ("2P") reserves at December 31, 2014, a 14% reduction versus year-end 2013.
  - Orlando net 2P reserves reduced by 2.1 mmboe following commitment to single well development solution (versus two well proposal at year-end 2013).
  - Huntington net 2P reserves reduced by 1.1 mmboe following 2014 production (0.8 mmboe) and observation of well performance (0.3 mmboe).
- New management team has implemented a strict focus on cost control and G&A reduction.
  - Q4 2014 employee costs reduced by 36% versus Q4 2013.
  - Q4 2014 total G&A reduced by 47% versus Q4 2013.

Financial

- 2014 revenues of $90.5 million (2013: $65.5 million) and Adjusted EBITDA of $43.7 million (2013: $47.9 million).
- Loss after tax of $119.5 million for 2014 (2013: $29.5 million loss) following full impairment of Trent & Tyne ($31.2 million) and impairment of Huntington asset ($88.9 million) and associated goodwill ($14.1 million) during 2014.
  - Huntington impairment largely driven by oil price drop in Q4 2014.
- Approximately 400,000 barrels (effective December 2014 – December 2015) hedged during Q4 2014 with a floor price of US$80.00 / bbl.
- End of year cash and restricted cash $95.7 million (2013: $104.9 million) ($55.5 million (2013: $85.1 million) restricted for purposes of Orlando development and BP hedging settlement).

Q4 2014 Operations Update

Huntington

- Q4 2014 net production of 395 boepd.
- Production was significantly impacted by issues with CATS, with production shut-in or constrained for all of Q4 2014.
- The field operator continues to work on gas disposal by way of an injection solution.
- The Huntington field partners continue to review how to maximize recovery from the field. Subsurface studies are ongoing which may support further capital investment in the field in the form of either a new production well or a sidetracked water-injection well in 2016.

(1) Iona also benefits from a 0.75% differential lifting entitlement and a 1.8% royalty interest in the Huntington field.

Trent & Tyne

- Q4 2014 net production of 227 boepd.
- Company announced that its proposed acquisition of the remaining 80% interest in the Trent & Tyne fields would not complete.

Orlando

- Full suite of offtake agreements finalized with CNR, the operator of the Ninian Central Platform ("NCP") infrastructure.
- Significant milestone to keep the project on track for first oil production at the end of 2016 and add significant production and value.
- NCP modifications on track and installation of Orlando equipment planned during summer shutdown in 2015.
- Orlando 2015-2016 project costs budget reduced from US$228 million to US$215 million (gross). Further cost savings in the order of 10-15% on the revised budget are being targeted by management.

Post Year End Operational Highlights

- Huntington production resumed in April 2015 with all four production wells returning to full production delivery. Since our last update of April 16, 2015 Huntington production has averaged 25,018 bbls of oil per day and 3,084 boe of associated gas per day exported into CATS (28,102 boe/day gross, 4,215 boe/day net to the Company's 15% working interest[(1)]).

(1) Iona also benefits from a 0.75% differential lifting entitlement and a 1.8% royalty interest in the Huntington field.

Funding Update

- The Company was in breach of the financial covenants of its US$275 million senior secured bonds (the "Bond") at December 31, 2014.
- Since year end, financial flexibility has been significantly increased for 2015 and 2016 following bondholder approval of a range of amendments to the terms of the Bond including:
    - Full waiver of financial covenants through to first oil from Orlando.
    - Conversion of interest payments to payment-in-kind for 2015 and 2016.
    - Scheduled 2016 amortization payments deferred until Bond maturity in September 2018.
    - Iona also to commence a review process to consider a range of alternatives to enable the Company to (i) fully fund Orlando and/or (ii) refinance the Bonds. A proposal needs to be presented to the bondholders by the end of June 2015 and, subject to bondholders' approval, implemented by the end of September 2015. If Iona does not provide a proposal or the proposal is not supported by the bondholders then the Company shall use its reasonable endeavors to arrange for the issue of a new super senior debt funding.
    - Both a proposal or a super senior debt funding require support from bondholders.

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

	Three Months ended December 31,			Year ended December 31,		
	2014	2013	**Change**	**2014**	2013	**Change**
Financial						
Crude oil and natural gas revenues	**5,367**	33,797	(84%)	**90,518**	65,508	38%
Operating costs	**(8,955)**	(9,462)	(5%)	**(34,928)**	(18,620)	88%
Depletion, depreciation & amortization	**(3,108)**	(16,206)	(81%)	**(52,977)**	(34,768)	52%
Gross (loss) profit	**(6,695)**	8,129	(182%)	**2,613**	12,120	(78%)
Gross (loss) profit before DD&A	**(3,588)**	24,335	(115%)	**55,590**	46,888	19%
(Loss) Income Before Tax	**(112,754)**	(39,006)	(189%)	**(178,761)**	(65,461)	(173%)
(Loss) Income After Tax	**(48,598)**	31,553	(254%)	**(119,450)**	29,466	(505%)
Per share – basic ($)	**(0.13)**	0.09		**(0.32)**	0.08	
Per share – diluted ($)	**(0.13)**	0.09		**(0.32)**	0.08	
Funds Flow(1)(2)	**(2,807)**	28,225	(110%)	**8,349**	31,324	(73%)
Per share – basic ($)	**(0.01)**	0.08		**0.02**	0.09	
Per share – diluted ($)	**(0.01)**	0.08		**0.02**	0.09	
Adjusted EBITDA(1)(2)	**(6,275)**	23,321	(127%)	**43,749**	47,866	(9%)
Per share – basic ($)	**(0.02)**	0.06		**0.12**	0.13	
Per share – diluted ($)	**(0.02)**	0.06		**0.12**	0.13	

	December 31, 2014	December 31, 2013
Cash and cash equivalents	31,565	19,808
Restricted cash	64,090	85,114
Working capital surplus(1)	73,670	79,075
Senior secured bonds	267,493	262,450
Common shares, end of period ('000s)	370,581	366,831
Fully diluted, end of period(1) ('000s)	403,929	400.975
Weighted average common shares–basic ('000s)	368,105	360,849
Weighted average common shares-diluted ('000s)	368,105	363,078

	Three Months ended December 31,			Year ended December 31,		
	2014	2013	Change	**2014**	2013	Change
Operational						
Crude oil and natural gas production (boepd)(3)						
Crude oil	**379**	2,209	(83%)	**1,803**	1,613	12%
Natural gas	**243**	745	(67%)	**426**	724	(41%)
Total	**622**	2,954	(79%)	**2,229**	2,337	(5%)
Realized sales prices						
Crude oil ($/boe)	**84.47**	105.65	(20%)	**104.03**	108.35	(4%)
Natural gas ($/mmcf)	**10.05**	12.20	(18%)	**10.08**	9.84	2%
Average ($/boe)	**76.05**	97.78	(22%)	**93.95**	90.02	4%
Operating costs(1) ($/boe)	**$140.86**	$33.49	321%	**$42.71**	$28.75	49%
Netback(1) ($/boe)	**($64.81)**	$64.29	(201%)	**$51.24**	$61.27	(16%)

(1) Non-GAAP measure – see "non-IFRS Measures" section within MD&A.
(2) See reconciliation on page 7.
(3) Based on 15.0% direct working interest volumes from Huntington.

KEY ASSET UPDATES

Huntington (15.0% Working Interest)

- Iona's net Huntington average production for Q4 2014 was 395 boepd.

- Huntington production during the quarter was impacted by issues at the CATS infrastructure which is used to export the field's gas production. When Huntington is unable to export gas it is unable to produce oil:

  - Huntington production was constrained from October 1, 2014 through to October 18, 2014 due to issues with CATS and was then suspended for scheduled maintenance of CATS. Upon CATS restarting in early December, an incident occurred at the CATS riser platform which restricted Huntington's ability to export gas. The CATS riser platform ties in a number of fields which introduce dry gas to the system which is used to blend the Huntington wet gas. In the absence of dry gas being available, the Huntington field is unable to access the CATS pipeline.
  - Huntington production resumed in April 2015 with all four production wells returning to full production delivery. Since our last update of April 16, 2015 Huntington production has averaged 25,018 bbls of oil per day and 3,084 boe of associated gas per day exported into CATS (28,102 boe/day gross, 4,215 boe/day net to the Company's 15% working interest[(1)]).

  (1) Iona also benefits from a 0.75% differential lifting entitlement and a 1.8% royalty interest in the Huntington field.

- The Huntington field partners continue to review how to maximize recovery from the field. Subsurface studies are on going which may support further capital investment in the field in the form of either a new production well or a new or sidetracked water-injection well in 2016.

- Following the rapid decline in oil prices during Q4 2014, the Company has recognized an $88.9 million impairment charge against the Huntington asset for the year ended December 31, 2014.

Trent & Tyne (20% Working Interest)

- Iona's net Trent & Tyne average production for Q4 2014 was 227 boepd.

- During the Q2 2014 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).

- On October 8, 2014, the Company announced that as per the terms of the SPA detailed above, a number of conditions which were required to be satisfied by October 28, 2014, were not going to complete.

- As a result of the Company determining that the Trent and Tyne assets would continue to generate break-even or negative cash flows for the remaining life of the field the Company's interests in the Trent and Tyne assets were fully written down to nil during Q3 2014 with an additional $3.4 million impairment charge taken during Q4 2014 (total charge for the year of $31.2 million) relating to an increase in the decommissioning estimate.

Orlando (75% Working Interest)

- During the quarter, Iona's Orlando development project team continued to implement the project activities for the subsea tie back to the NCP.

- On October 8, 2014 the Company announced that all necessary agreements had been signed with CNR, the Operator of the NCP infrastructure, securing the offtake arrangements for the Orlando field development. The Construction and Tie-in Agreement describes how the parties will work together to deliver first oil from the Orlando development by the end of 2016. Integrated planning is already at an advanced stage to commence the installation of brownfield equipment on NCP in 2015. Subsea installation and drilling activities are planned to commence in spring 2016.

- The development plan for Orlando comprises the re-entering of the suspended 3/3b-13z well to drill a 3,000 foot horizontal production well which will be completed with dual Electric Submersible Pumps ("ESPs"). A subsea pipeline, power supply and control umbilical will be laid between the well-head and NCP approximately 10 km to the south west of the Orlando field.

- The project remains on track to deliver first production during Q4 2016.

- The Company's latest capex estimate for the project is US$215 million (gross) for 2015 – 2016. Management is targeting further cost savings on the revised estimate in the order of 10-15%.

- Initial production rates from the field are estimated by Iona at c. 10,500 bopd (gross) with year one decline in the range of 50 – 60% and year 2 decline in the range of 30-40%.

RESERVES UPDATE

Iona's estimated net reserves as of December 31, 2014 as audited by Gaffney Cline & Associates ("GCA") are summarised in the table below.

	Total net (mmboe)			Pre-tax NPV10 ($mm)		
	1P	**2P**	**3P**	**1P**	**2P**	**3P**
Orlando	6.3	9.4	12.8	163.8	288.1	347.9
West Wick	5.1	9.7	12.2	96.0	312.9	372.1
Kells	3.9	6.6	8.0	40.8	144.6	198.0
Huntington	2.4	3.5	4.4	65.1	125.4	185.6
Total	17.7	29.2	37.4	365.7	871.0	1,103.6

Notes:
1. Iona's working interest in the Huntington field is 15%, however its net reserves include a 0.75% royalty interest in addition to the 15% working interest.

- Total net 2P reserves as of December 31, 2014 have been assessed at 29.2 mmboe representing a 14% reduction versus year-end 2013.

    - This reduction is largely related to the Orlando field where selection of a single well development solution versus the previously contemplated two well scenario has reduced 2P reserves by 2.1 mmboe compared to year-end 2013. The single well development concept represents a more capital efficient development and reduces Iona's capex exposure. A second well may be added later depending on the field's performance however this has been excluded at this time.

    - Huntington 2P reserves have reduced by 1.1 mmboe versus year-end 2013. Of this 0.8 mmboe represents production during 2014, while the remainder is a reflection of observed well performance and updated reservoir modelling. It should be noted that Huntington reserves include a contribution from the deeper Fulmar reservoir (also referred to as Maxwell).

    - Kells reserves are unchanged versus year-end 2013. Limited capex has been deployed on the Kells project as Iona has focused on delivering Orlando first production. Iona is reviewing how to maximize the value of Kells. The current Kells license agreement requires submission of a field development plan by August 2015. This will not be achieved and Iona is in discussions with the Department of Energy and Climate Change ("DECC") to seek an extension to the license. There is a risk that DECC may not be willing to extend the licence.

    - West Wick reserves are unchanged versus year-end 2013. Limited capex has been deployed on the West Wick project as Iona has focused on delivering Orlando first production. Iona is reviewing how to maximise the value of West Wick. West Wick is classified as a Fallow B Rescued license and Iona is required to report to DECC by the end of April 2015 with progress. There is a risk that DECC may not be willing to extend the licence.

PERSONNEL HIGHLIGHTS

- In November 2014 the Company announced a number of senior management appointments:
    - Robert Gair, Chief Financial Officer
    - Kevin Holley, Corporate Controller
    - James Lund, Head of Operations and Development
    - Gregor Maxwell, Head of Business Development

MANAGEMENT DISCUSSION AND ANALYSIS

Business of the Company

Iona is an oil and natural gas production, appraisal, and development corporation focused on the United Kingdom's Continental Shelf ("UKCS").

The following Management's Discussion and Analysis ("MD&A") of Iona Energy Inc. ("Iona" or "the Company") is based on and should be read in conjunction with the consolidated financial statements and accompanying notes of the Company as at and for the period ended December 31, 2014 which have been prepared in accordance with International Financial Reporting Standards ("IFRS") and should be read in conjunction with, the Annual Information Form ("AIF") for the year ended December 31, 2014, the MD&A for the year ended December 31, 2013 and the audited consolidated financial statements as at and for the year ended December 31, 2013. Copies of these documents and additional information about Iona are available on SEDAR at www.sedar.com.

This MD&A is dated April 28, 2015. 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 and contingent and prospective resources, 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. 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, 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

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.

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 generated from operating activities before changes in non-cash working capital. Adjusted EBITDA is calculated as net income before finance costs, transaction costs, derivative gains and losses, taxes, impairment, 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:

		Year ended December 31,	
		2014	2013
Cash flow generated from operating activities	$	**34,796**	15,294
Changes in non-cash working capital balances:			
Accounts receivable		**(10,483)**	11,896
Prepaid expenses		**64**	(722)
Inventory		**(229)**	581
Accounts payable and accrued liabilities		**(15,799)**	4,275
Funds Flow	$	**8,349**	31,324

The following table reconciles net (loss) / income for the year to Adjusted EBITDA:

		Year ended December 31,	
		2014	2013
Net (loss) / income for the year	$	**(119,450)**	29,466
Income tax expenses (recovery)		**(59,311)**	(94,927)
Finance costs		**32,713**	23,172
Finance income		**(13)**	(20)
(Gain) / loss on risk management contracts		**(3,916)**	30,917
Transaction costs		**6,579**	910
Impairment of goodwill		**14,058**	-
Impairment of oil and gas properties		**120,112**	23,580
Depletion, depreciation and amortization		**52,977**	34,768
Adjusted EBITDA	$	**43,749**	47,866

TRANSACTIONS

During Q2 2014 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).

On October 8, 2014, the Company announced that as per the terms of the SPA detailed above, a number of conditions which were required to be satisfied by October 28, 2014, were not going to complete. Perenco has disagreed with the position of the Company and in Q3 2014 wrote to Iona attempting to terminate the SPA on the grounds of the Company's alleged breach of contract, stating that it was entitled to retain the deposit of US$2 million and reserving its rights to claim damages. The Company strongly believes that it has complied with its obligations under the SPA and accordingly is entitled to the repayment of the deposit and will robustly defend any action raised by Perenco. On this basis, the Company has recognized the full amount of $2 million within Accounts Receivable as at December 31, 2014. Perenco as operator is unlikely to sanction further investment in Trent & Tyne and therefore the Trent & Tyne producing assets will continue to generate break-even or negative cash flows for the remaining life of the field and as such has the Company has recognized an impairment charge of $31.2 million with respect to the Trent & Tyne producing assets in Q3 and Q4 2014.

On October 27, 2014 Iona UK closed out the 361,976 outstanding put options (effective October 2014 – July 2015) realizing proceeds of $1.9 million. Simultaneously, the Company put in place “costless collar” arrangements over 396,197 barrels (effective December 2014 – December 2015) with a floor price of US$80.00 / bbl and a ceiling price of US$92.75 / bbl.

On December 15, 2014 the Company announced that - as a result of continued production interruptions at Huntington (mainly linked to the availability of the CATS gas export infrastructure), a delay in projected first oil at Orlando from 2015 to Q4 2016 and the rapid decline in oil prices - the Company may breach certain of the Bond covenants during the next twelve month operating cycle. As a result of this, the Company also confirmed that constructive discussions had commenced with some of its largest bondholders to increase financial flexibility to facilitate the Company’s new strategy. On March 5, 2015 the Company announced that it was in breach of the financial covenants of its US$275 million senior secured bonds at December 31, 2014.

Post year end, the Company announced on March 12, 2015 that it had called a bondholder meeting to consider certain amendments to the terms of the bonds. Subsequently on March 27, 2015 the Company announced that the bondholder meeting had successfully approved all amendments. The amendments are more particularly detailed in the section below entitled “SENIOR DEBT INSTRUMENTS” on page 12.

PRODUCTION AND PRICING

		Three months ended December 31,			Twelve months ended December 31,		
		2014	2013	% Change	**2014**	2013[1]	% Change
Total Petroleum and natural gas production (net) by product & project							
Huntington[2]							
Crude Oil	bbl	**34,831**	203,272	(83%)	**658,198**	424,301	55%
Natural Gas	boe	**1,443**	36,202	(96%)	**79,372**	60,826	30%
Trent & Tyne							
Natural Gas	boe	**20,902**	32,310	(35%)	**76,133**	179,848	(58%)
Total petroleum and natural gas production (net)	boe	**57,176**	271,784	(79%)	**813,703**	664,975	22%
Average Daily Production (net) by product							
Crude Oil	bopd	**379**	2,209	(83%)	**1,803**	1,613	12%
Natural Gas	boepd	**243**	745	(67%)	**426**	724	(41%)
Total average daily production (net)	boepd	**622**	2,954	(79%)	**2,229**	2,337	(5%)

(1) Adjusted for start of production for Huntington on April 11, 2013

(2) Based on 15.0% direct working interest volumes from Huntington

Average net production for the three and twelve months ended December 31, 2014 was 622 boepd and 2,229 boepd respectively compared to average net production during the comparable periods in 2013 of 2,954 boepd and 2,337 boepd respectively. The decrease in crude oil production to 379 bopd during the three months ending December 31, 2014 compared to 2,209 bopd during the three months ending December 31, 2013 was a result of the planned and unplanned shutdowns and restrictions in the CATS infrastructure throughout Q4 2014. The increase in crude oil production to 1,803 bopd during the twelve months ended December 31, 2014 compared to 1,613 bopd during twelve months ended December 31, 2013 was a result of a full period of production from the Huntington field in 2014 compared to production beginning on April 11 in 2013, offset in the third and fourth quarters by planned and unplanned shutdowns and restrictions in the CATS infrastructure.

SALES

		Three months ended December 31,			Twelve months ended December 31,		
		2014	2013	% Change	**2014**	2013[1]	% Change
Total Petroleum and natural gas sales (net) by product & project							
Huntington[2]							
Crude Oil	bbl	**41,224**	214,060	(81%)	**662,263**	406,932	63%
Natural Gas	boe	**1,443**	36,202	(96%)	**79,372**	60,826	30%
Trent & Tyne							
Natural Gas	boe	**20,902**	32,310	(35%)	**76,133**	179,848	(58%)
Total petroleum and natural gas sales (net)	boe	**63,569**	282,572	(78%)	**817,768**	647,606	26%
Average Daily Sales by product (net)							
Crude Oil	bopd	**448**	2,209	(80%)	**1,814**	1,547	17%
Natural Gas	boepd	**243**	745	(67%)	**426**	724	(41%)
Total average daily sales (net)	boepd	**691**	2,954	(77%)	**2,240**	2,271	(1%)
Realized sales prices							
Crude oil	$/boe	**84.47**	105.65	(20%)	**104.03**	108.35	(4%)
Natural gas	$/mmcf	**10.05**	12.20	(18%)	**10.08**	9.84	2%
Average	$/boe	**76.05**	97.78	(22%)	**93.95**	90.02	4%

(1) Adjusted for start of production for Huntington on April 11, 2013

(2) Based on 15.0% direct working interest volumes from Huntington

Average daily sales for the three and twelve months ended December 31, 2014 was 691 boepd and 2,240 boepd respectively compared to average daily sales during the comparable periods in 2013 of 2,954 boepd and 2,271 boepd respectively. The decrease in average daily sales to 691 boepd during the three months ending December 31, 2014 compared to 2,954 boepd during the three months ending December 31, 2013 and 2,240 boepd during the twelve months ended December 31, 2014 compared to 2,271 during the twelve months ended December 31, 2013 was a result of the planned and unplanned shutdowns and restrictions in the CATS infrastructure through Q4 2014.

The average realized oil price for the three and twelve months ended December 31, 2014 was $84.47 and $104.03 respectively per bbl (three and twelve months ended December 31, 2013 - $105.65 and $108.35 respectively per bbl). The average realized gas price for the three and twelve months ended December 31, 2014 was $10.05 per mcf and $10.08 per mcf respectively (three and twelve months ended December 31, 2013 - $12.20 per mcf and $9.84 per mcf respectively).

REVENUE

	Three months ended December 31,			Year ended December 31,		
	2014	2013	% Change	**2014**	2013	% Change
Petroleum and natural gas sales by product						
Crude oil	**3,482**	22,614	(85%)	**68,894**	44,090	56%
Natural gas	**1,352**	6,837	(80%)	**9,642**	14,398	(33%)
Royalty interest	**553**	4,246	(87%)	**9,759**	6,688	46%
Condensate	**(20)**	100	(120%)	**2,223**	332	570%
Total	**5,367**	33,797	(84%)	**90,518**	65,508	38%

Revenue was $5.4 million and $90.5 million for the three and twelve months ended December 31, 2014 (2013: $33.8 million and $65.5 million), respectively.

Oil revenues decreased from the same three month period in the previous year as a result of restricted production at the Huntington field. Year over year revenues increased as the current year reflects a full period of production from the Huntington field compared to production beginning on April 11 in 2013, offset by planned and unplanned shutdowns in the last two quarters. Gas sales in the three and twelve months ended December 31, 2014 decreased as a result of previously discussed restrictions in the CATS infrastructure and reduced production levels at the Trent & Tyne fields.

Of the total revenues of $5.4 million and $90.5 million for the three and twelve months ended December 31, 2014 ($33.8 million and $65.5 million for the three and twelve months ended December 31, 2013), $3.5 million, 65% of total revenue and $68.9 million, 76% of total revenue, was generated from oil production (2013: $22.6 million, 67% of total revenue and $44.1 million, 67% of total revenue), respectively, $1.4 million, 25% of total revenue and $9.6 million, 11% of total revenue, was generated from gas production (2013: $6.8 million, 20% of total revenue and $14.4 million, 22% of total revenue), respectively, $553,000, 10% of total revenue and $9.8 million, 11% of total revenue, was generated through a gross overriding royalty interest in the Huntington field (2013: $4.2 million, 13% of total revenue and $6.7 million, 10% of total revenue), respectively, and ($20,000), 0% of total revenue and $2.2 million, 2% of total revenue from condensate (2013: $100,000, 0% of total revenue and $332,000, 1% of total revenue), respectively.

INVENTORY

Inventory for the quarter ended December 31, 2014 was $943,000 (2013: $1.8 million). Inventory relates to the Company's share of stock remaining in the FPSO storage tanks at December 31, 2014. 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,			Year ended December 31,		
	2014	2013	% Change	**2014**	2013	% Change
Operating costs	**8,955**	9,462	(5%)	**34,928**	18,620	88%
Depletion and depreciation	**3,108**	16,206	(81%)	**52,977**	34,768	52%
Total	**12,063**	25,668	(53%)	**87,905**	53,388	65%

Operating costs for the three and twelve months ended December 31, 2014 were $9.0 million and $34.9 million during the three and twelve months ended December 31, 2014 respectively compared to $9.5 million and $18.6 million for the three and twelve months ended December 31, 2013. Operating costs were broadly flat in Q4 2014 versus Q4 2013 reflecting the largely fixed cost base of Iona's production assets while there was an overall increase in operating costs over the year compared to 2013 due to 2014 having a full year of production from the Huntington field. Depletion decreased during the three months and increased during the twelve months ended December 31, 2014 to $3.1 million and $53.0 million respectively compared to $16.2 million and $34.8 million respectively during the three and twelve months ended December 31, 2013. The decrease in depletion for the three months ended December 31, 2014 is a result of decreased production during the fourth quarter while the increase in depletion and depreciation for the twelve months ended December 31, 2014 is due to a full period of production from the Huntington field in the current year compared to production beginning on April 11, 2013.

The costs were generated from the Huntington and Trent & Tyne fields as discussed in *Key Projects.*

OPERATING NETBACKS

		Three months ended December 31,				Year ended December 31,		
		2014	2013	% Change		**2014**	2013	% Change
		$/boe	$/boe			**$/boe**	$/boe	
Average Selling Price	$	**76.05**	97.78	(22%)	$	**93.95**	90.02	4%
Operating Cost		**(140.86)**	(33.49)	321%		**(42.71)**	(28.75)	49%
Netback from Operations	$	**(64.81)**	64.29	(201%)	$	**51.24**	61.27	(16%)

Operating costs include all costs to produce and sell the commodity. Operating costs for Q4 of 2014 increased to $140.86 per boe compared to $33.49 per boe in Q4 2013 as a result of restricted production at Huntington shut-in during the fourth quarter where a large portion of operating costs are fixed. Operating costs for the year ended December 31, 2014 increased to $42.71 per boe compared to $28.75 in the same period in 2013 as a result of restricted production from Huntington in Q3 and Q4 2014.

GENERAL AND ADMINISTRATIVE EXPENSES

		Three months ended December 31,			Year ended December 31,		
		2014	2013	% Change	**2014**	2013	% Change
Consulting fees / wages		**528**	820	(36%)	**4,157**	3,632	14%
Professional fees		**395**	435	(9%)	**823**	1,485	(45%)
Stock option expense		**134**	981	(86%)	**1,200**	3,896	(69%)
Depreciation		**36**	8	350%	**156**	37	322%
Insurance		**(245)**	516	(147%)	**21**	917	(98%)
Travel, office costs and other		**999**	708	41%	**3,272**	2,120	54%
Total		**1,847**	3,468	(47%)	**9,629**	12,087	(20%)
Per boe	$boe	**29.06**	12.17		**11.77**	18.66	

General and administrative costs were $1.8 million and $9.6 million for the three and twelve months ended December 31, 2014 compared to $3.5 million and $12.1 million for the three and twelve months ended December 31, 2013.

General and administrative costs decreased 47% from the three month comparative period in 2013 as a result of decreased consulting fees and wages due to staff reductions in Canada and the UK along with reduced professional fees, stock option expense and insurance. Travel, office costs and other increased due to increased corporate activity. Stock option expense decreased due to stock options forfeited in the quarter along with, the natural decline in expense due to graded vesting.

General and administrative costs decreased 20% for 2014 versus 2013 mainly as a result of decreased professional fees and stock option expense offset by a slight increase in consulting fees and wages due to the Company's increased staff levels in Q2 2014 and Q3 2014 relating to the proposed transfer of operatorship of the Trent & Tyne asset. Professional fees include legal, audit and tax fees. As noted above stock option expense decreased due a natural decline in expense due to graded vesting as well as forfeitures, this was offset in the third quarter of 2013 as a result of stock option grants to new employees.

The Company is seeking to reduce general and administrative costs to be more appropriate to a low cost operator. Since the year end further organizational changes have been implemented to reduce costs.

FOREIGN EXCHANGE

	Three months ended December 31,			Year ended December 31,		
	2014	2013	% Change	**2014**	2013	% Change
Foreign exchange gain / (loss)	**(849)**	6,543	(113%)	**(1,929)**	6,991	(128%)

During the three and twelve months ended December 31, 2014, the Company recognized a foreign exchange loss of $849,000 and $1.9 million (2013: gain of $6.5 million and $7.0 million, respectively). The exchange loss in the quarter arose primarily as a result of the strengthening of the GBP against the USD increasing the value of the GBP payable working capital balances held in Iona UK.

RELATED PARTY TRANSACTIONS

During the three and twelve months ended December 31, 2014, the Company was charged $70,000 (2013: $61,000) and $451,000 (2013: $716,000) respectively, in legal fees of which $NIL (2013: $97,000) related to share issuance costs by a law firm where a director of the Company is a partner, of which $70,000 (2013: $29,000) is included in accounts payable and accrued liabilities as at December 31, 2014.

Included in accounts receivable is $101,169 (2013: $117,483) due from a former officer and director of the Company who resigned from the Company's management team and Board. As of the date of this MD&A $101,169 remains to be collected. The amounts owing are non-interest bearing and secured by 559,524 common shares. The Company expects full repayment of the remaining balances in 2015.

On September 12, 2014 the Company entered into an agreement for two Demand Promissory Notes in the amount of $480,000 ($500,000 CAD) bearing interest at 3.25% with two members of senior management. These notes are secured by 1,250,000 outstanding common shares and 1,250,000 warrants issued on August 29, 2014. At December 31, 2014 these promissory notes remained outstanding. The Company expects full repayment of the Demand Promissory Notes in the future.

Except as disclosed, all related party transactions 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.

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 net proceeds of $260 million. As at December 31, 2014 the fair value of the Bonds were $212 million (2013: $275 million). The Bonds mature on September 30, 2018.

At issuance, the Bonds had the following key features:

- annual coupon rate of 9.5% payable semi-annually
- were issued at 97.5% of par
- were callable in whole or in part at the option of Iona UK at any time
- at issuance, the maturity schedule commenced 30 months after September 30, 2013, the Bonds were to be repaid at 15% of the face value every six months with a 25% final payment at maturity plus a specified premium
- the Bonds contained certain early redemption options under which the Company has the option to redeem all or a portion of the bonds at various redemption prices.

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, 2014 the derivative was valued at $Nil (2013: $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.

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 restricted group which is defined as Iona UK and Iona Huntington Ltd (currently Huntington, Trent & Tyne, Orlando, Kells, Ronan and Oran). Additionally, a working interest of at least fifty percent was required to be maintained in Orlando and Kells.

At issuance, under the Bond Agreement the Company was required to 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 finance costs, transaction costs, derivative gains and losses, taxes, impairment, 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.

Under the Bond agreement “net interest bearing debt” is defined as the book value of the interest bearing financial indebtedness less the cash and cash equivalents. “Restricted group equity” is defined as the aggregate book value of the restricted group's total equity treated as equity in accordance with IFRS (including subordinated loans), excluding any fair value adjustment attributable to the BP structured energy derivative.

The Company was in breach of the Leverage Ratio at December 31, 2014. Given under the Bond Agreement an event of default constitutes two consecutive quarterly covenant violations the amounts in respect of the senior debt facility continue to be classified as non-current liabilities as at December 31, 2014.

The table below delineates the Company’s position with respect to the Bond covenants at December 31, 2014.

	31-December-14	Covenant
Liquidity as defined (In thousands of US dollars)	$86,809	Greater than $30,000
Restricted Group Capital Employed Ratio	36%	Greater than 40%
Group Capital Employed Ratio	36%	Greater than 40%
Leverage Ratio	4.07	Not greater than 3.0x

The above calculation includes restricted cash in the definition of cash as changed in the amendment to the Bond Agreement effected May 6, 2014.

On March 27, 2015, Bondholders approved a range of amendments to the Bond agreement which provide the Company with significant additional financial flexibility including:

- Full waiver of financial covenants through to first oil at Orlando including net debt / EBITDA and minimum capitalization ratios.

- Conversion of interest payments to payment-in-kind (“PIK”) (i.e. added to principal, therefore non-cash) for 2015 and 2016. PIK interest rate increased to 12.5%.

- Scheduled 2016 amortization payments deferred until Bond maturity in September 2018.

- New independent director to be appointed to the Board of the Company.

- Bondholders to receive a fee in the form of non-transferable warrants to purchase common shares of the Company representing in aggregate 10% of the existing common shares of the Company. The warrants shall have an exercise price of CAD$0.05 per warrant. The warrants shall be exercisable until September 27, 2018 and will be subject to a hold period of four months and a day from issuance.

Iona has also initiated a review process to consider all options to (i) ensure the business is fully funded to first oil at Orlando and/or (ii) enable the refinancing of the Bonds. A proposal is required to be presented to the bondholders by the end of June 2015 and, subject to bondholders' approval, implemented by the end of September 2015.

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, 2014 are presented in the table below:

	Level 1	Level 2	Level 3	Total Fair Value
Current assets				
Derivative financial instrument assets (embedded derivative)	-	-	-	-
Derivative financial instrument assets (put options)	-	7,817	-	7,817
	-	-	-	-
Current Liabilities				
Derivative financial instrument liabilities (call options)				
Non-current liabilities				
Derivative financial instrument liabilities (call options)	-	21,020	-	21,020

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

	Three Months Ended December 31		Year Ended December 31	
	2014	2013	**2014**	2013
Cost of derivative options	-	53	-	(7,186)
Unrealized gain / (loss) on commodity hedges	**9,191**	(11,381)	**34,410**	(17,937)
Realized gain / (loss) on commodity hedges	**1,936**	(914)	**(30,494)**	(5,794)
Total gain / (loss) on commodity hedges	**11,127**	(12,242)	**3,916**	(30,917)

All other financial assets are classified as loans and receivables and are accounted for on an amortized cost basis. All financial liabilities are classified as other liabilities.

COMMITMENTS

In addition to accounts payable and accrued liabilities, and based on management's best estimate, the Company has the following contractual obligations:

	December 31, 2014				
	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**	-	68	51	85
UK Segment					
Office lease	**4,147**	451	1,354	903	1,439
Equipment leases	**35,513**	11,224	24,289	-	-
Drilling, completion, facility construction	**49,919**	27,759	22,160	-	-
Total UK Segment	**89,579**	39,434	47,803	903	1,439
Total Contractual Obligations	**89,783**	39,434	47,871	954	1,524

Excluded from the table above on January 19, 2012, the Company's UK Subsidiary, Iona UK, acquired full ownership and operatorship from Fairfield Cedrus Limited ("Fairfield") of a 100% interest in Block 3/8d containing the Kells Oil Field. Iona UK reimbursed Fairfield on closing for $8.5 million in pre-development expenditures related to the Kells field. In addition, upon the approval by DECC of a field development plan in respect of Kells, Iona will be obligated to make a cash payment of $5.0 million to Fairfield and pay a net royalty of $2.50 per barrel of production from the Kells Oil Field.

Additionally, future staged payments will be made by Iona to Sorgenia and MPX commencing six months after first production from Orlando. The first payment will be $7.0 million with additional payments of $7.0 million, $7.0 million, $4.0 million, and $4.0 million made every six months thereafter respectively, amounting to a total payment of $29.0 million over 3 years.

On February 21, 2013, the Company completed the sale of a 25% working interest in the Orlando and Kells fields to Volantis Exploration (a subsidiary of Atlantic Petroleum) for total gross proceeds of $36.8 million on close and a pro-rata share of the future staged payment obligations referred to above.

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 used in operating activities, funds flow, during the fourth quarter of 2014 was ($2.8 million) a decrease from $28.2 million generated in the fourth quarter of 2013 primarily due to a decrease in revenues resulting from production constraints in Q4 2014.

Cashflow from financing activities
Cash used in financing activities during the fourth quarter of 2014 was ($318,000) compared to ($33.5 million) in the fourth quarter of 2013.

Cashflow from investing activities
Cash used in investing activities in the fourth quarter of 2014 was ($3.2 million) compared to cash generated from investing activities of $28.2 million in the fourth quarter of 2013.

The Company initiated discussions with its largest bondholders in late 2014 to increase financial flexibility for the Company. On March 27, 2015 bondholders approved a range of amendments to the bond agreement which provide Iona with significant additional financial flexibility including a waiver of financial covenants through 2015 and 2016, conversion of interest to payment-in-kind and a deferral of scheduled 2016 amortization payments.

The Company has also initiated a review process to consider all options to enable (i) the business is fully funded to first oil at Orlando, and/or (ii) the refinancing of the Bonds. The review will result in a transaction proposal (the “Proposal”) being made to bondholders for their approval by June 30, 2015 and if the Proposal is approved then it is required to be implemented by September 30, 2015. If Iona does not provide a Proposal or the Proposal is not supported by the bondholders then the Company shall use its reasonable endeavors to arrange for the issue of a new super senior debt funding (the “Super Senior Funding”) to be made available by no later than September 30, 2015.

Both implementation of the Proposal and the Super Senior Funding are subject to bondholder approval at a bondholders’ meeting. There can be no guarantee that bondholders will vote in favour of either the Proposal or the Super Senior Funding. If neither the Proposal nor the Super Senior Funding are supported by bondholders then the Company will likely default under the terms of the Bonds during 2015. In an event of default, Bondholders could require immediate repayment of the Bonds which would cast significant doubt as to the Company’s ability to continue as a going concern and the Company might be unable to realize its assets and discharge its liabilities in the normal course of business.

As at December 31, 2014, the Company had net assets of $75.5 million, working capital of $73.7 million and $39.4 million of commitments due in the next twelve months.

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, 2014, 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, 2014 would have impacted the comprehensive loss of the Company for the year ended December 31, 2014 by $30,000 (2013: $21,000).

In addition at December 31, 2014, the Company held $8,606,524 (£5,514,174) (2013: $11,629,030 (£7,035,957)) of accounts payable in British Pound Sterling. Assuming all other variables remain constant, a 1% increase or decrease in foreign exchange rates at December 31, 2014 would impact the comprehensive loss of the Company for the year ended December 31, 2014 by $86,065 (2013: $116,290).

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 370,580,868 Common Shares, 3,750,000 warrants and 29,597,500 stock options outstanding.

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

	December 31, 2014		December 31, 2013	
Stock Options	**Number of Options**	**Weighted Average Exercise Price CAD$**	Number of Options	Weighted Average Exercise Price CAD$
Beginning of year	**34,750,000**	**$0.59**	27,080,000	$0.58
Granted	**6,600,000**	**$0.44**	11,395,000	$0.63
Exercised	**-**	**-**	-	-
Forfeited	**(11,752,500)**	**$0.59**	(3,725,000)	$0.54
End of year	**29,597,500**	**$0.56**	34,750,000	$0.59
Exercisable, end of year	**20,167,500**	**$0.58**	18,167,500	$0.59

Date of Grant	**Issued**	**Exercise Price CAD$**	**Weighted Average Remaining Contractual Life**	**Date of Expiry**	**Number Exercisable Dec 31, 2014**
May 31, 2011	7,600,000	$0.60	0.42 years	May 31, 2015	7,600,000
April 12, 2012	10,900,000	$0.57	2.28 years	April 12, 2017	8,362,500
March 5, 2013	4,610,000	$0.63	3.18 years	March 5, 2018	2,405,000
October 23, 2013	600,000	$0.63	3.81 years	October 23, 2018	300,000
April 30, 2014	637,500	$0.54	4.33 years	April 30, 2019	187,500
July 1, 2014	750,000	$0.49	4.47 years	June 19, 2019	187,500
September 1, 2014	4,500,000	$0.40	3.67 years	September 1, 2019	1,125,000
	29,597,500				20,167,500

On April 30, 2014, the Company issued 1,350,000 stock options to purchase 1,350,000 common shares of the Company to employees of the Company (of which 712,500 stock options were forfeited during the year). The options were issued with an exercise price of $0.54 per share, vest as to one quarter immediately and one quarter on each of the first, second and third anniversaries of the date of grant and have a five year term from the date of issuance.

On July 1, 2014 and September 1, 2014 Iona Energy issued 750,000 and 4,500,000 stock options respectively to purchase 2,100,000 common shares of the Company to employees of the Company. The options were issued with an exercise price of $0.49 and $0.40 per share respectively, vest as to one quarter immediately and one quarter on each of the first, second and third anniversaries of the date of grant and have a five year and four year term, respectively, from the date of issuance.

SUMMARY OF QUARTERLY RESULTS

($ thousands, except per share amounts)

	2014				2013			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Revenue	**5,367**	**22,403**	**27,100**	**35,648**	33,797	18,010	11,843	1,858
Average Daily Production (boepd)								
Crude oil [1]	**379**	**2,269**	**2,284**	**3,475**	2,585	1,799	1,179	-
Natural Gas	**243**	**467**	**475**	**680**	765	927	655	316
Total	**622**	**2,736**	**2,759**	**4,155**	3,350	2,726	1,834	316
Net (loss) / income	**(48,598)**	**(42,487)**	**(28,027)**	**(338)**	31,395	899	9,117	(11,945)
(Loss) / income per share – basic	**(0.13)**	**(0.12)**	**(0.08)**	**(0.00)**	0.09	0.00	0.02	(0.03)
(Loss) / income per share – diluted	**(0.13)**	**(0.12)**	**(0.08)**	**(0.00)**	0.09	0.00	0.02	(0.03)
Funds Flow	**(2,807)**	**(19,277)**	**3,345**	**27,088**	24,181	4,983	3,911	(1,751)
Funds Flow per share – basic	**(0.01)**	**(0.05)**	**0.01**	**0.07**	0.08	0.01	0.01	(0.01)
Funds Flow per share – diluted	**(0.01)**	**(0.05)**	**0.01**	**0.07**	0.08	0.01	0.01	(0.01)
Adjusted EBITDA[2]	**(6,275)**	**10,082**	**12,166**	**27,776**	23,321	18,263	3,001	3,281
Adjusted EBITDA per share – basic	**(0.02)**	**0.03**	**0.03**	**0.07**	0.05	0.05	0.01	0.01
Adjusted EBITDA per share – diluted	**(0.02)**	**0.03**	**0.03**	**0.07**	0.05	0.05	0.01	0.01
Working capital surplus/ (deficit)	**73,670**	**85,924**	**88,847**	**88,776**	79,075	71,247	(155,367)	(47,275)
Total assets	**460,158**	**482,169**	**544,072**	**545,159**	545,079	631,690	516,606	513,002
Weighted average common shares-basic	**368,105**	**368,054**	**366,831**	**366,831**	360,849	366,824	377,060	342,597
Weighted average common shares–fully diluted	**368,105**	**368,054**	**366,831**	**366,831**	363,078	366,824	377,060	342,597

(1) Q2 2013 production has been adjusted for start of production for Huntington on April 11, 2013.

(2) Q3 and Q4 2013 EBITDA has been adjusted for the restatement of Q3 2013 finance costs. See Note 16 of the Q3 2014 interim condensed financial statements.

Comparative information has been restated to reflect the change in presentation currency from Canadian to US Dollar using the average rate for income statement and cash flow data and the rate at the end of the period for balance sheet data in each respective quarter.

The decrease in net income from Q4 2014 compared to net income from Q3 2014 is primarily due to decreased production from the Huntington field and the impairment charge taken against goodwill and the Huntington asset.

Revenue, Funds Flow and Adjusted EBITDA were substantially impacted by production constraints throughout 2014 as a result of unplanned shutdowns of the Voyageur FPSO and ongoing gas export challenges, both related to Huntington. This decrease in revenue significantly impacted net income in Q3 and Q4 of 2014. Fluctuations in production and the Brent benchmark price have also contributed to the fluctuations in oil and gas sales.

CRITICAL ACCOUNTING ESTIMATES

The Company's management made judgements, assumptions and estimates in the preparation of the consolidated 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, 2014.

The preparation of consolidated 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:

Functional currencies

The Company's operations change significantly each reporting period, this change can impact the functional currencies of the Company and its subsidiaries. Management makes judgments 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.

Depletion, depreciation and amortization amounts

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.

Share based compensation plans

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.

Joint arrangements

Judgment is required to determine when the Company has joint control over an arrangement, which requires an assessment of the relevant activities and when the decisions in relation to those activities require unanimous consent. The Company has determined that the relevant activities for its joint arrangements are those relating to the operating and capital decisions of the arrangement, including the approval of the annual capital and operating expenditure work program and budget for the joint arrangement, and the approval of chosen service providers for any major capital expenditure as required by the joint operating agreements applicable to the entity's joint arrangements.

Judgment is also required to classify a joint arrangement. Classifying the arrangement requires the Company to assess their rights and obligations arising from the arrangement. Specifically, the Company considers:

- The structure of the joint arrangement – whether it is structured through a separate vehicle
- When the arrangement is structured through a separate vehicle, the Company also considers the rights and obligations arising from:
  - The legal form of the separate vehicle;
  - The terms of the contractual arrangement; and
  - Other facts and circumstances, considered on a case by case basis.

This assessment often requires significant judgment. A different conclusion about both joint control and whether the arrangement is a joint operation or a joint venture, could materially impact the accounting.

Funding arrangements

The accounting for funding arrangements requires management to make certain estimates and assumptions on whether a liability exists at the time of the funding. Specifically, the Company considers the terms of the contract and applies the concepts of obligating events, probabilities and providing for future events. An assessment of any contract will consider factors such as:

- the stage of any asset in its development life cycle;
- the allocation of any proven or probable recoverable reserves to that asset;
- an assessment as to whether the arrangement results in the transfer of the risks, rewards and obligations associated with funding on that asset;
- requirements of when any future payments would first arise, for example on reaching commercial production and the likelihood of achieving this;
- the period over which the payment or repayment of monies received under the arrangement; and
- whether legal title to the asset passes but also the economic substance of transactions, other events and conditions, and not merely the legal form.

This assessment requires the exercise of judgment.

Exploration and Evaluation Assets

The accounting for exploration and evaluation ("E&E") assets requires management to make certain estimates and assumptions, including whether exploratory wells have discovered economically recoverable quantities of reserves. Designations are sometimes revised as new information becomes available. If an exploratory well encounters hydrocarbons, but further appraisal activity is required in order to conclude whether the hydrocarbons are economically recoverable, the well costs remain capitalized as long as sufficient progress is being made in assessing the economic and operating viability of the well. Criteria used in making this determination include evaluation of the reservoir characteristics and hydrocarbon properties, expected additional development activities, commercial evaluation and regulatory matters. The concept of "sufficient progress" is an area of judgment, and it is possible to have exploratory costs remain capitalized for several years while additional drilling is performed or the Company seeks government, regulatory or partner approval of development plans.

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.

Determination of Cash Generating Units

The Company's E&E assets and development oil and gas properties are grouped into Cash Generating Units ("CGUs"). CGUs are defined as the lowest level of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations. Factors considered in the classification include the integration between assets and the way in which management monitors the operations, as well as the planned development for the field or licence. The recoverability of the Company's E&E assets and development oil and gas properties is assessed at the CGU level and therefore the determination of a CGU could have a significant impact on impairment losses or impairment reversals.

Impairment Indicators

The Company monitors internal and external indicators of impairment relating to E&E assets and property, plant and equipment and goodwill. For E&E assets the following are examples of the types of indicators used:

- The entity's right to explore in an area has expired or will expire in the near future without renewal;
- No further exploration or evaluation is planned or budgeted;
- The decision to discontinue exploration and evaluation in an area because of the absence of commercial reserves; or
- Sufficient data exists to indicate that the book value will not be fully recovered from future development and production.

For development oil and gas properties, the following are examples of the indicators used:

- A significant and unexpected decline in the asset's market value or likely future revenue;
- A significant change in the asset's reserves assessment;
- Significant changes in the technological, market, economic or legal environments for the asset; or

- Evidence is available to indicate obsolescence or physical damage of an asset, or that it is underperforming expectations.

The assessment of impairment indicators requires the exercise of judgment. If an impairment indicator exists, then the recoverable amounts of the cash-generating units and/or individual assets are determined based on the higher of value-in-use and fair values less costs of disposal calculations. These require the use of estimates and assumptions, such as future oil and natural gas prices, discount rates, operating costs, future capital requirements, decommissioning costs, exploration potential, reserves and operating performance. These estimates and assumptions are subject to risk and uncertainty. Therefore, there is a possibility that changes in circumstances will impact these projections, which may impact the recoverable amount of assets and/or CGUs.

Decommissioning Obligation

Decommissioning obligations will be incurred by the Company at the end of the operating life of wells. The ultimate asset decommissioning costs and timing are uncertain and cost estimates can vary in response to many factors including changes to relevant legal requirements and their interpretation, the emergence of new restoration techniques, the prevailing rig rates or experience at other production sites. As a result, there could be significant adjustments to the provisions established which could materially affect future financial results.

Derivative financial instruments

The Company's has in place risk management contracts in the form of commodity put and call options. The fair value assigned to the derivative financial instruments uses level II assumptions with the main inputs to the valuation being the quoted forward prices for commodities, market interest rates, and volatility factors.

Commitments

Commitment disclosure includes estimates of the total cost of long-term projects in which there are many contingent factors and which could be revised either upwards or downwards based on the actual results of operations.

Contingent Liabilities

Accounting for contingent liabilities requires the Company to make assumptions regarding the likelihood that a future event will occur. This assessment often requires significant judgment. A different conclusion regarding the likelihood of the future event, could materially impact the accounting.

Recognition of Deferred Tax Assets

Accounting for income and profit taxes is a complex process requiring management to interpret frequently changing laws and regulations and make judgments related to the application of tax law, estimate the timing of temporary difference reversals, and estimate the realization of tax assets. All tax filings are subject to subsequent government audits and potential reassessment. These interpretations and judgments and changes related to them can potentially impact current and deferred tax provisions, deferred income tax assets and liabilities and net post-tax profit or loss.

Accordingly, in common with other international oil and gas companies conducting their business through government licences to operate, the provision for income tax, profits tax and other tax liabilities is subject to a degree of measurement uncertainty. The recognition of deferred tax assets requires a determination of the likelihood that the Company will generate sufficient taxable earnings in future periods, in order to utilize recognized deferred tax assets. Assumptions about the generation of future taxable profits depend on management's estimates of future cash flows. These estimates of future taxable income are based on forecast cash flows from operations (which are impacted by production and sales volumes, oil and natural gas prices, reserves, operating costs, decommissioning costs, capital expenditure and other capital management transactions) and judgment about the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize the net deferred tax assets recorded at the reported date could be impacted.

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) plc (“Iona UK”) from Pounds Sterling to US dollars with effect from October 1, 2013. This change was triggered by the achievement of plateau oil and gas production in the Huntington field and the issuance of $275 million of US Dollar denominated debt by Iona UK. Oil and gas prices received by the Company are benchmarked against the US Dollar Brent oil standard. 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 2013 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.

ACCOUNTING POLICY CHANGES

Changes in accounting policies
As of January 1, 2014, the Company adopted several new IFRS interpretations and amendments in accordance with the transitional provisions of each standard. A brief description of each new accounting policy and its impact on the Company's consolidated financial statements follows below:

IAS 36 "Impairment of Assets" has been amended to reduce the circumstances in which the recoverable amount of cash generating units "CGUs" is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. The retrospective adoption of these amendments will only impact Iona’s disclosures in the notes to the consolidated financial statements in periods when an impairment loss or impairment reversal is recognized.

IFRIC 21 "Levies" was developed by the IFRS Interpretations Committee ("IFRIC") and is applicable to all levies imposed by governments under legislation, other than outflows that are within the scope of other standards (e.g., IAS 12 "Income Taxes") and fines or other penalties for breaches of legislation. The interpretation clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. It also clarifies that a levy liability is accrued progressively only if the activity that triggers payment occurs over a period of time, in accordance with the relevant legislation. Lastly, the interpretation clarifies that a liability should not be recognized before the specified minimum threshold to trigger that levy is reached. The retrospective adoption of this interpretation does not have any impact on Iona’s consolidated financial statements.

Future Changes in Accounting Policies:
The Company 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 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2017, with earlier adoption permitted. IFRS 15 will be applied by Iona on January 1, 2017 and the Company is currently evaluating the impact of the standard on Iona’s consolidated financial statements.

In July 2014, the IASB completed the final elements of IFRS 9 "Financial Instruments." The Standard supersedes earlier versions of IFRS 9 and completes the IASB’s project to replace IAS 39 "Financial Instruments: Recognition and Measurement." IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss’ impairment model and a substantially-reformed approach to hedge accounting. The Standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 9 will be applied by Iona on January 1, 2018 and the Company is currently evaluating the impact of the standard on Iona's consolidated financial statements.

Other future standards and interpretations, and amendments to standards and interpretations resulting from improvements to IFRS that did not have any impact on the accounting policies, financial position or performance of the Company are:

- IAS 19 – Employee contributions – amendments effective January 1, 2015
- IFRS 2 – Definitions of vesting conditions – amendments effective January 1, 2015
- IFRS 8 – Aggregation of operating segments – amendments effective January 1, 2015
- IFRS 8 – Reconciliation of the total reportable segments' assets to the entity's assets - amendments effective January 1, 2015
- IAS 16 and IAS 38 – Revaluation method – proportionate restatement of accumulated depreciation/amortization amendments effective January 1, 2015
- IAS 24 – Key management personnel – amendments effective January 1, 2015
- IFRS 3 – scope exceptions for joint ventures – amendments effective January 1, 2015
- IFRS 13 – portfolio exception – amendments effective January 1, 2015
- IAS 40 – ancillary services – amendments effective January 1, 2015
- IFRS 10 and IAS 28 – Sale or Contribution of Assets between an Investor and its Associate or Joint Venture - amendments effective January 1, 2016
- IFRS 10, IFRS 12 and IAS 28 – Investment Entities – amendments effective January 1, 2016
- IFRS 11 – Accounting for Acquisitions of Interests in Joint Operations - amendments effective January 1, 2016
- IFRS 14 – Regulatory Deferral Accounts - amendments effective January 1, 2016
- IAS 1 – Disclosure Initiative - amendments effective January 1, 2016
- IAS 16 and IAS 38 – Clarification of Acceptable Methods of Depreciation and Amortization - amendments effective January 1, 2016
- IAS 16 and IAS 41 – Bearer Plants - amendments effective January 1, 2016
- IAS 27 – Equity Method in Separate Financial Statements - amendments effective January 1, 2016
- IFRS 5 – Non-current Assets Held for Sale and Discontinued Operations - amendments effective January 1, 2016
- IFRS 7 – Servicing Contracts - amendments effective January 1, 2016
- IFRS 7 – Applicability of the offsetting disclosures to condensed interim financial statements - amendments effective January 1, 2016
- IAS 19 – Discount Rate - amendments effective January 1, 2016
- IAS 34 – Disclosure of information 'elsewhere in the interim financial report - amendments effective January 1, 2016

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.

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 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 installations (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 achieve revenues from 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. 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. See further details provided in the Senior Debt Instruments section above.

Loss from Operations
Iona had a retained deficit as at December 31, 2014 of $106,717,000 and retained earnings of $12,733,000 as at December 31, 2013. 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 primarily in UK Brent. Brent 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 economics 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 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.

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 licenses 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, are 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.

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 oil and gas regulatory regime is changing in 2015. The existing regulatory, DECC, will be replaced by the Oil and Gas Authority ("OGA"). It is unclear at this stage whether this will have any significant impact on operating conditions in the UK North Sea.

The UK government does not assess a crown royalty against production. The current tax regime in the UK is favorable to companies of 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.

Subsequent to December 31, 2014 the UK Government amended the tax legislation to decrease the supplemental tax rate applicable to Oil and Gas companies to 20% effective January 1, 2015 and also to introduce a new investment allowance (the "Investment Allowance") to reduce the amount of adjusted ring fence profits subject to the supplementary charge. The portion of profits reduced by the allowance will be dependent on a company's investment expenditure and will be generated at 62.5% of that spend. The Investment Allowance will replace the SFA and BFA. Had this been in effect at December 31, 2014 the Company would have recorded a deferred tax asset of $41.4 million instead of $54.2 million.

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, 2014, which is available on SEDAR under the Company’s profile at www.sedar.com.

Notes Regarding Oil and Gas Disclosure

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.