MANAGEMENT'S DISCUSSION & ANALYSIS

FOR THE THREE MONTHS AND YEAR ENDED DECEMBER 31, 2013

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This Management's Discussion and Analysis of financial condition and results of operations ("MD&A") is based on information available to April 28, 2014 and should be read in conjunction with Madalena Energy Inc.'s ("Madalena" or the "Company") audited consolidated financial statements ("Consolidated Financial Statements") for the year ended December 31, 2013 and the accompanying notes. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Madalena's Management prepared the MD&A, while the Audit Committee of the Madalena Board of Directors (the "Board") reviewed and recommended its approval by the Board. Additional information relevant to the Company's activities contained in its continuous disclosure documents, including our quarterly financial statements and the Annual Information Form ("AIF"), is available on SEDAR at www.sedar.com.

Effective July 30, 2013, the Company changed its name from Madalena Ventures Inc. to Madalena Energy Inc.

Basis of Presentation

This MD&A and the Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated and have been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board. Production volumes are presented on a before royalties basis.

Unless otherwise indicated, tabular financial amounts, other than per share amounts, are in thousands of Canadian dollars.

Non-GAAP Measures

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as netbacks, and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide readers with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-GAAP measure is presented in the " Financial Results" section of this MD&A.

INTRODUCTION AND OVERVIEW

Overview

Madalena is an independent, Canadian-based, international and domestic upstream oil and gas company whose main business activities include exploration, development and production of crude oil, natural gas liquids and natural gas.

Internationally, Madalena holds three blocks within the Neuquén basin in Argentina comprised of approximately 132,200 net acres on the Coiron Amargo (approximately 34,950 net acres), Curamhuele (approximately 50,600 net acres) and Cortadera (approximately 46,650 net acres) blocks. Madalena's three blocks within the Neuquén Province are strategically positioned in key areas of the basin for the evolving unconventional shales and tight sand plays (including the Vaca Muerta shale, Agrio shale and Mulichinco tight sand play) as well as multiple conventional zones of interest for oil and gas exploration and development.

Domestically, Madalena's core area of operations is located in the greater Paddle River area of west-central Alberta, where the Company holds approximately 196 gross (154 net) sections of land (approximately 78% average working interest).

The Company's strategy

Madalena's strategy is to create value through the generation of a portfolio of high quality oil and gas assets in proven hydrocarbon areas characterized by competitive fiscal terms, significant development potential and high impact exploration opportunities.

The Corporation has a portfolio of exploration and development opportunities within the Neuquén basin of Argentina focused on the delineation of unconventional shale plays, tight sand reservoirs and conventional oil & gas zones of interest. The Neuquén basin is an oil and gas producing basin in central-western Argentina. The portfolio consists of three prospective blocks, each comprised of large acreage positions believed to be on trend with known discoveries and supported by extensive 2D and 3D seismic coverage with existing well data on the blocks and offsetting well data from nearby area activity. The basin has extensive pipeline and facility infrastructure and a developed service industry. The basin remains relatively underexplored and underdeveloped and includes multiple evolving unconventional shale plays in addition to various conventional exploration and development opportunities.

Internationally, Madalena is focused on delineating its unconventional resources in the Vaca Muerta shale, Basal Quintuco and Lower Agrio shale and unlocking its estimated 34.8 Billion Barrels of Oil Equivalen ("boe") of P50 best estimate total petroleum initially in place net to Madalena as evaluated by Ryder Scott Company, L.P. ("Ryder Scott") in its resource report effective December 31, 2013 ("Ryder Scott Resource Report"). The potential prize which Madalena is working to unlock includes a P50 best estimate contingent resource of 19.5 million boe (95% crude oil and NGLs) and a P50 best estimate prospective resource of 2.8 billion boe (45% crude oil and NGLs) as evaluated by Ryder Scott in its resource report effective December 31, 2012 (see advisory section for further details).

Additional unconventional or tight sand plays which are not included in the above mentioned resource numbers, but which are of interest across Madalena's international acreage, include the Mulichinco, Los Molles shale, Lajas and Lotena formations.

As part of a blended business strategy between unconventional shale and tight sand delineation activities, Madalena is also focused on implementing horizontal drilling technology to its high impact, high deliverability, conventional oil and gas reservoirs in the Neuquén basin. Madalena's first use of horizontal technology in Argentina is centered around the Sierras Blancas light oil reservoir which is a conventional reservoir sourced from the Vaca Muerta shale.

Domestically, Madalena's Canadian assets include 154 net sections of land in the greater Paddle River area of west-central Alberta that support multiple light oil and liquids-rich gas resource plays. The entrance into the domestic E&P space in November, 2012 allowed Madalena the opportunity to increase production and cash flow from lower risk development programs, while executing a turnaround plan throughout 2013 to reposition the Company to develop, delineate and grow its international assets and further its overall business plan.

2013 HIGHLIGHTS AND OUTLOOK

- Established and integrated an experienced, full-cycle operating team capable of executing both internationally and domestically;
- Repositioned Madalena for flexibility with respect to its Neuquén basin assets with the signing of three revised block contracts (new contractual amendments and/or extensions) at each of the Company's Curamhuele, Coiron Amargo and Cortadera blocks in Argentina;.
- Conducted an extensive technical review of the Company's unconventional shale resources on its three land blocks within the Neuquén basin effective December 31, 2012 with Ryder Scott and evaluated the Vaca Muerta shale, Lower Agrio shale and Basal Quintuco across the Coiron Amargo, Curamhuele and Cortadera blocks with Ryder Scott Resource Report and prepared a comprehensive resource report which was released on April 30, 2013 and effective December 31, 2012.Highlights of the independent resource evaluation are as follows:
    - Best Estimate P50 total petroleum initially in place ("PIIP") of 34.8 billion boe (51 % crude oil and natural gas liquids ("NGLs")), comprised of:
        - Best Case P50 discovered PIIP ("DPIIP") of 257.4 million boe (95 % crude oil and NGLs); and
        - Best Case P50 undiscovered PIIP ("UPIIP") of 34.6 billion boe (50 % crude oil and NGLs).
    - Best Estimate P50 contingent and prospective resources as follows:
        - Best case P50 prospective resources of 2.8 billion boe (45 % crude oil and NGLs), and
        - Best case P50 contingent resources of 19.4 million boe (95 % crude oil and NGLs).
    - A further breakdown (by block) of the petroleum initially in place and resources aggregating such total are shown in a series of tables in the advisory section of this document.
- Increased proved plus probable reserves ("P+P") by 19% to 4.7 MMboe which is primarily driven by the Company's conventional assets. Net present value of these P+P reserves before tax, discounted at 10%, increased 49% to $50.2 million;
- A large inventory of horizontal locations on Madalena's western Canadian and Argentinean lands remains unbooked;
- Q4 – 2013 production averaged 1,271 boe/d (56% oil and liquids), an increase of 101% from Q4 – 2012
- Madalena has been successfully recapitalized through raising a total of $19.5 million in 2013 and an additional $23 million in February, 2014.
- Maintained a strong balance sheet with zero debt and $8.0 million in positive working capital at the end of the fourth quarter in 2013. With the subsequent $23 million raised in February 2014, unutilized credit facilities of $13 million, cash flow from production and other financial gains expected through 2014, Madalena is positioned to meet its commitments and execute on its 2014 plan;

- In late 2013, Madalena successfully implemented its first use of North American based horizontal drilling technology on its international assets focused initially at its Coiron Amargo block in the Neuquen basin. Horizontal technology was applied to the Sierras Blancas formation which is a conventional light oil reservoir sourced from the Vaca Muerta shale across the Coiron Amargo block. The CAN.xr-2(h) well was re-entered and drilled horizontally and has produced approximately 63,000 barrels of oil in the first three months of 2014. The results to date on the CAN.xr-2(h) horizontal have exceeded management's expectations and as a result, Madalena has commenced a multi-well horizontal drilling program in Sierras Blancas for 2014. To kick-off 2014, the CAN-15(h) well was recently drilled horizontally and during testing operations the highest rates were achieved on a 12 mm choke setting, when the well flowed at a rate of 1,393 bbls/d of oil with 3,301 mcf/d of associated natural gas for a total of 1,943 Boe/d (72% oil) over a 5 hour period. *(see INTERNATIONAL OPERATIONS below).* The next Sierras Blancas horizontal in the multi-well program for 2014 is expected to commence drilling in Q2-2014. Madalena has a 35% working interest in the Coiron Amargo block.

- Madalena has established a 2014 capital budget of $48 million, $37 million of which is allocated to Argentina. The 2014 budget is focused on a combination of high impact horizontal wells in the Sierras Blancas light oil play, along with unconventional shale and tight sand delineation work (including completions, fracture stimulations and new drilling), 3D seismic shooting on the Company's international assets, re-entries in Argentina and horizontal work on the Canadian assets.

INTERNATIONAL OPERATIONS - *Neuquén Basin, Argentina*

Coiron Amargo Block

- Industry activity in and around Madalena's Coiron Amargo block (approximately 35,000 net acres) including developments in the greater Loma La Lata and Loma Campana areas has seen a significant step change from initial exploration and appraisal drilling in 2012 to an accelerated exploitation / development phase in the unconventional Vaca Muerta shale through 2013 and into 2014. Over 150 Vaca Muerta shale wells have been drilled in and around this area and a number of significant joint ventures (or other transactions) over the last 14 months have been announced. These largely involve large integrated exploration and production companies such as YPF, Chevron, Shell, Total SA, Wintershall, Petrobras and others. YPF and Chevron have announced a 140 well drilling program in 2014 targeting the Vaca Muerta shale to the west of Madalena's acreage and they expect to increase production from the Vaca Muerta shale to approximately 80,000 bbls/d by 2017 in this area. Madalena's Coiron Amargo block is strategically positioned within this area of Vaca Muerta shale resource development and Madalena continues to execute its business plan in this area.
- The Coiron Amargo block is divided into a North and South region with active drill programs being executed in both areas. Coiron Amargo Notre (the northern portion of the block) is currently under a 25 year exploitation (development) concession. The southern portion of the block, Coiron Amargo Sur, is currently under an exploration contract which was extended until November 8, 2014 by way of an official decree signed by the Province of Neuquén in Argentina on November 12, 2013. Subsequent to November 8, 2014, Madalena has the ability to extend Coiron Amargo Sur through further exploration, evaluation and/or exploitation (development) phases.
- The focus of Madalena's business plan for the Coiron Amargo block includes:
    i) Continue to advance the Company's Vaca Muerta shale activities with a combination of new delineation wells and completion techniques (stimulations and/or multi-stage fracs);
    ii) Drill, complete, test and tie-in high impact horizontal wells targeting Vaca Muerta sourced light oil from the Sierras Blancas reservoir; and
    iii) Technically assess deep gas potential on the block in response to offsetting industry activity.

- Recently, the Company has intensified its focus on the Vaca Muerta shale given the unconventional resource opportunity across the Coiron Amargo block. The block is strategically positioned within the Neuquén basin in the shallower portion of the Vaca Muerta oil window and in an area where over 150 Vaca Muerta shale wells have been drilled over the last 12 to 14 months. Industry activity continues to increase offsetting the Coiron Amargo block where Madalena drilled the CAS.x-14 and the CAS.x-15 vertical wells in Coiron Amargo Sur for the Vaca Muerta shale in 2013. The CAS.x-14 and CAS.x-15 wells were drilled and cased encountering approximately 105 and 114 meters respectively of Vaca Muerta shale on logs. Completion (stimulation work and/or multi-stage frac) activities on these wells are expected to commence in Q2 – 2014.

- Madalena has implemented a balanced business strategy between unconventional shale delineation and potentially high impact horizontal drilling. Accordingly, Madalena successfully implemented North American based horizontal technology and experience on the Coiron Amargo block. As the first implementation of horizontal technology internationally, the CAN.xr-2(h) well was re-entered, drilled and completed horizontally in the Sierras Blancas light oil reservoir which is a conventional reservoir which is sourced from the Vaca Muerta shale. The CAN.xr-2(h) well has now been producing since late 2013 and has exceeded management's expectations. The well has been producing oil at restricted rates for most of Q1 – 2014. Cumulative oil production for Q1-2014, based on field estimates, was approximately 63,000 barrels of oil plus associated solution gas. Average daily production was approximately 700 bbls/d and 1,560 mcf/d of associated solution gas for a total of 978 boe/d (72% oil) over a three month period in Q1-2014. The well has been recently tied into a permanent pipeline system to the central plant and gas dehydration and compressor facility and, accordingly, associated solution gas volumes will be realized as sales in future quarters. Madalena has a 35% working interest in the CAN.xr-2(h) well.

- Encouraged by the results of the CAN.xr-2(h) horizontal, Madalena has commenced a multi-well horizontal drilling program for 2014. The CAN-15(h) well, in which the Company has a 35% working interest, was recently drilled horizontally in the Sierras Blancas light oil reservoir in the Coiron Amargo block to a total measured depth of 3,750 metres with a horizontal lateral section of approximately 692 metres in length. This well is the second horizontal well drilled into the Sierras Blancas which is a conventional light oil reservoir sourced from the Vaca Muerta shale across the Coiron Amargo block. The well was subsequently cased and completed with a 3.5" slotted liner and a multi-rate production test was carried out through temporary production facilities. Throughout the multi-rate production test, the CAN-15(h) well flowed without artificial lift equipment and was tested for approximately 75 hours at various choke settings ranging from 6 mm to 12 mm in size with the following flow rates observed during the test:

  i) With the production test only being carried out on a portion of the horizontal lateral section as planned, the highest rates were achieved on a 12 mm choke setting, when the CAN-15(h) well was flowed at a rate of 1,393 bbls/d of oil with 3,301 mcf/d of associated natural gas for a total of 1,943 Boe/d (72% oil) over a 5 hour period and at an average flowing pressure of approximately 1,263 psi.

  ii) On an 8mm choke setting, the CAN-15(h) well was flowed at a rate of 745 bbls/d of oil with 1,990 mcf/d of associated natural gas for a total of 1,077 Boe/d (69% oil) over a 29 hour period and at an average flowing pressure of approximately 1,629 psi.

  iii) During the test period of 75 hours, the total gross produced cumulative volumes were approximately 2,553 barrels of oil and approximately 7,210 mcf of natural gas, for a total of approximately 3,754 barrels of oil equivalent (68% oil) gross. No significant flowing pressure declines were observed throughout the testing period and water cuts ranged from 0% to 3% throughout the test period.

- Operationally, Madalena and its partners currently have a completion rig running on the Coiron Amargo block with another drilling rig scheduled to mobilize to the block in Q2 to continue drilling a combination of high impact horizontals and Vaca Muerta shale delineation wells.
- Two 3D seismic programs were shot at Coiron Amargo Sur during the second quarter of 2013 and were subsequently processed in the third quarter. The Coiron Amargo block (both north and south regions) is now almost entirely covered with 3D seismic.

Curamhuele Block

- The greater El Trapial / Curamhuele region is an evolving area within the Neuquén basin which is seeing increased exploration and appraisal activity for unconventional shale plays and tight sand reservoirs. Chevron has recently announced that a second focus area for Chevron in the Vaca Muerta shales is the El Trapial block which is adjacent and to the east of Madalena's 90% working interest Curamhuele block. At El Trapial, Chevron is drilling and testing four exploration wells in 2014 to further assess the unconventional shale potential. Others, such as YPF are also drilling on lands offsetting Madalena's Curamhuele block for unconventional shale and tight sand plays.
- The primary zones of interest across the Curamhuele block are the unconventional Vaca Muerta shale, Lower Agrio shale and liquids rich Mulichinco sands. The block is also prospective for other conventional reservoirs.
- To satisfy a portion of the 2014 block commitments, Madalena has recently shot an approximately 75 square kilometer 3D seismic survey at Curamhuele. Processing of this data is currently underway. The Company plans to merge this newly acquired data with the existing 125 square kilometer 3D survey on the block. This will provide 3D seismic coverage on the entire northern portion of the Curamhuele block.
- To satisfy the remaining 2014 block commitments, Madalena plans to execute two high impact re-entries of the Yp.x-1001 and Ch.x-1 wellbores. Through these re-entries, Madalena plans to test an estimated 200 meter thick tight Mulichinco sand liquids-rich gas play and an estimated 225 meter thick oil zone in the Lower Agrio shale (which is a second emerging unconventional shale play in Argentina). In response to offsetting industry activity, Madalena is also evaluating the Vaca Muerta shale across the block.
- To accelerate exploration and development activities on the block, the Company continues to assess different opportunities with RBC Capital Markets ("RBC"), Madalena's exclusive advisor related to its Neuquén basin assets, in respect of a possible joint venture partnership or other transaction.

Cortadera Block

- On January 15, 2014, the Corporation announced that, on the Cortadera Block, the joint venture partnership consisting of Apache Corporation, Gas y Petroleo del Neuquén SA and Madalena had signed an amended contract agreement to formalize a multi-year extension of the initial exploration period and inclusion of subsequent exploration periods. Subsequent to that agreement and following an application and approval process, the first exploration period for Cortadera was extended by way of an official decree which was signed by the Province of Neuquén in Argentina. This extension provides the partnership until October 26, 2014 to satisfy the remaining work commitments on the block, which involves an upcoming re-entry of the CorS.x-1 well. Under the amended agreement, and subsequent to conducting the upcoming re-entry work, the partnership at Cortadera has the option to enter into a second exploration period extending to October 25, 2018 and a third exploration period extending to October 25, 2021, or extend the Cortadera Block through potential further evaluation and/or exploitation phases.
- Madalena and its new block partner YPF S.A. (acquired through YPF's recent purchase of the Apache subsidiary in Argentina) plan to re-enter the previously drilled CorS.x-1 Vaca Muerta test well to evaluate the uphole Mulichinco tight sand play (or other zone of interest). Madalena expects that its share of any costs for the work performed will not be significant due to YPF's continued earning obligations which include carrying Madalena

for the majority of the anticipated costs.

DOMESTIC OPERATIONS – *Greater Paddle River Area, Alberta, Canada*

- Domestically, Madalena's core area of operations is located in the greater Paddle River area, where the Company holds approximately 196 gross (154 net) sections of land (approximately 78% average working interest) in west-central Alberta that support light oil and liquids-rich gas resource plays. Madalena entered the domestic E&P space in November, 2012 and executed horizontal drilling activity in 2013 with a focus of bringing increased production and cash flow into the company.
- Drilled 6 (5.92 net) wells in 2013 including 4 development horizontals and 2 exploration wells which qualify for Canadian Exploration Expense ("CEE") , resulting in 4 (4 net) oil wells;
- Continued to make progress on the Ostracod horizontal oil project with 5 (4.92 net) wells drilled in 2013. Four (4.0 net) of these wells are currently on production while the fifth (0.92 net), a significant step-out well drilled in late 2013, continues to be evaluated. Q4 – 2014 production from the producing Ostracod wells represented 70% of the Company's domestic production of 1,098 boe/d. Operating costs for the Ostracod horizontal wells in Q4, 2013 were $14.54 per boe. Overall, the Company has gained valuable insights during 2013 on its emerging Ostracod project and has an inventory of horizontal development locations on its 58 net section land position.
- Madalena's domestic focus is to exploit its inventory of horizontal development locations on its Ostracod oil, Notikewin/Wilrich liquids-rich gas and other emerging oil & liquids-rich gas resource plays in the area. Madalena also holds more than 100 net sections (100% W.I.) which are prospective for the Duvernay shale.

SUMMARY FINANCIAL AND OPERATIONAL RESULTS

	Three months ended December 31		Year ended December 31	
	2013	2012	**2013**	2012
Financial - Canadian $000s, except per share amounts				
Oil and gas revenue	**5,633**	3,012	**17,960**	5,545
Net loss	**(20,527)**	(4,933)	**(23,285)**	(8,865)
Per share – basic and diluted	**(0.06)**	(0.02)	**(0.07)**	(0.03)
Business combinations	-	16,090	-	16,090
Capital expenditures	**13,121**	6,310	**43,296**	22,851
Working capital	**8,016**	30,025	**8,016**	30,025
Equity outstanding – 000s				
Common shares	**364,029**	314,307	**364,029**	314,307
Stock options	**19,530**	22,334	**19,530**	22,334
Operating				
Average Daily Production				
Crude oil and condensate – Bbls/d	**551**	327	**392**	173
Natural gas – Mcf/d	**3,366**	1,377	**3,346**	369
NGLs – Bbls/d	**160**	78	**137**	20
Total - boe /d(1)	**1,271**	634	**1,086**	254
Average Sales Prices				
Crude oil and condensate - $/Bbl	**73.71**	74.75	**79.69**	75.23
Natural gas - $/Mcf	**3.52**	3.35	**3.18**	3.41
NGLs - $/Bbl	**54.99**	48.04	**53.61**	48.04
Total - $/boe(1)	**48.16**	51.66	**45.28**	59.86
Operating Netbacks				
$/boe(1)	**16.82**	13.49	**15.25**	18.18

(1) Refer to - "Oil, Natural Gas Liquids and Natural Gas Conversions to boe" in Advisory.

FINANCIAL RESULTS

Net Loss and Comprehensive Loss

Canadian $000s, except per share amounts	Three months ended December 31 **2013**	2012	Year ended December 31 **2013**	2012
Net loss	**(20,527)**	(4,933)	**(23,285)**	(8,865)
Comprehensive income (loss)	**(24,016)**	(6,219)	**(32,006)**	(12,076)
Net loss Per share – basic & diluted	**(0.06)**	(0.02)	**(0.07)**	(0.03)

The net loss for the three months ended December 31, 2013 (the "Quarter") was $20.5 million (2012 – $4.9 million). The net loss for the year ended December 31, 2013 ("YTD") was $23.3 million (2012 – $8.9 million). The Company recorded an impairment charge on its Canadian assets in the amount of $19.7 million during the Quarter and YTD. Further details are provided under "Impairment" later in this report.

In addition, the Company realized foreign exchange gains of $1.0 million (2012 – nil) and $3.6 million (2012 – nil) for the Quarter and YTD, respectively. These gains were a result of beneficial exchange rates between the Argentine peso and the Canadian dollar that existed in the market at the time of funding the Argentina exploration and development activity from Canada.

The increase in the comprehensive loss compared to the net loss was a result of the changes in the Argentine peso to Canadian dollar exchange rate applied to the net assets of the Company's operations in Argentina. During the Quarter and YTD, the Argentine peso weakened against the Canadian dollar. The foreign currency translation loss for the Quarter and YTD was $3.5 million (2012 – loss $1.3 million) and $8.7 million (2012 – loss $3.2 million), respectively.

Production

Average daily production	Three months ended December 31 **2013**	2012	Year ended December 31 **2013**	2012
Argentina				
Crude oil (Bbls/d)	**154**	195	**170**	140
Natural gas (Mcf/d)	**117**	132	**126**	55
Total daily production (boe/d)	**173**	217	**191**	149
Canada				
Crude oil and condensate (Bbls/d)	**397**	132	**222**	33
Natural gas (Mcf/d)	**3,249**	1,245	**3,221**	314
Natural gas liquids (Bbls/d)	**160**	78	**137**	20
Total daily production (boe/d)	**1,098**	417	**895**	105
Corporate				
Total daily production (boe/d)	**1,271**	634	**1,086**	254
% Oil & NGLs	**56%**	64%	**49%**	76%

Neuquén *Basin, Argentina*

The Company produces oil, with a small amount of solution gas, from 8.0 wells (2.8 net) at Coiron Amargo Norte (northern portion of the block). Reduced oil production due to natural declines from the CAN 7 vertical well, which commenced production in July 2012, was the primary cause of the reduction in the comparative quarterly production rates, while increased production year over year was primarily a result of natural production declines from the CAN 5 and CAN 8 wells, which commenced production in June 2012 and February 2013, respectively.

Canada

Production and the increase in production from the Canadian operations for the Quarter and YTD was a result of a strategic domestic acquisition and entry into the domestic E&P sector on November 1, 2012. Production was 1,098 boe/d (Q4-2012 – 417 boe/d) and 895 boe/d (2012 – 105 boe/d) during the Quarter and YTD, respectively. The Company has a mature base production of approximately 275 boe/d from 36 (22 net) oil and gas wells, with the balance of the Company's production being generated from four 100% working interest Ostracod horizontal oil wells and one 100% working interest Notikewin gas well. Q4 – 2014 production from the four Ostracod wells represented 70% of the Company's domestic production.

Average Realized Prices

	Three months ended December 31		Year ended December 31	
Canadian $	**2013**	**2012**	**2013**	**2012**
Argentina				
Crude oil – $/bbl	**86.05**	77.63	**81.17**	76.35
Natural gas – $/mcf	**4.66**	4.03	**4.48**	4.16
Total – $/boe	**79.53**	72.19	**75.20**	73.21
Canada				
Crude oil and condensate – $/bbl	**68.92**	70.49	**77.93**	70.49
Natural gas – $/mcf	**3.48**	3.27	**3.12**	3.27
Natural gas liquids – $/bbl	**54.39**	48.04	**54.76**	48.04
Total - $/boe	**43.21**	40.99	**38.93**	40.99

The Company has the following physical natural gas and oil contracts in place:

Type	Period	Volume	Price Floor	Price Ceiling	Index
Natural gas fixed	April 1, 2014 to Oct. 31, 2014	500 GJ/d	$3.45CDN	$3.45 CDN	AECO
Natural gas fixed	April 1, 2014 to Oct. 31, 2014	300 GJ/d	$3.55CDN	$3.55 CDN	AECO
Natural gas fixed	April 1, 2014 to Oct. 31, 2014	300 GJ/d	$4.43CDN	$4.43 CDN	AECO
Natural gas fixed	April 1, 2014 to Oct. 31, 2014	300 GJ/d	$4.52CDN	$4.52 CDN	AECO
Crude oil call options	Jan. 1, 2014 to Dec. 31, 2014	50 bbl/d	-	$100 US	WTI
Crude oil call options	Jan. 1, 2014 to Dec. 31, 2014	50 bbl/d	-	$100 US	WTI
Crude oil swap	Feb 1, 2014 to Dec 31, 2014	50 bbl/d	-	$100 CDN	WTI
Crude oil call options	Jan. 1, 2015 to Dec. 31, 2015	50 bbl/d	-	$95 US	WTI

The fair value of commodity contracts is determined by discounting the difference between the contracted price and published forward price curves as at the balance sheet date, using the remaining contracted petroleum and natural gas volumes. The fair value of commodity contracts as at December 31, 2013 was a net payable and an unrealized loss of $90,387 (2012 - $nil). Realized gains for the Quarter and YTD were $53,562 and $132,814 (2012 –

nil and nil) and are included in interest and other income on the Statement of Loss and Comprehensive Loss. The commodity contracts are classified as level 2 within the fair value hierarchy.

During 2012, the Company did not have any physical natural gas and oil contracts in place.

Revenue

	Three months ended December 31		Year ended December 31	
Canadian $000s, except per boe	**2013**	**2012**	**2013**	**2012**
Argentina				
Crude oil	**1,219**	1,390	**5,031**	3,889
Natural gas	**50**	49	**206**	83
	1,269	1,439	**5,237**	3,972
Canada				
Crude oil and condensate	**2,499**	853	**6,257**	853
Natural gas	**1,040**	375	**3,677**	375
Natural gas liquids	**825**	345	**2,789**	345
	4,364	1,573	**12,723**	1,573
Corporate Total	**5,633**	3,012	**17,960**	5,545
Corporate - $/boe	**48.16**	51.66	**45.28**	59.86

Neuquén Basin, Argentina
Oil sales decreased by $0.2 million in the Quarter from the corresponding period in 2012 as a result of lower production volumes from the CAN-5 and CAN-7 wells. YTD oil sales increased by $1.1 million from the corresponding period in 2012 as a result of production from the CAN-5 and CAN-8 wells, which commenced production in June 2012 and February 2013, respectively..

Canada
Petroleum, natural gas and natural gas liquid sales from the Canadian operations for the Quarter and YTD were a result of a strategic domestic acquisition on November 1, 2012. Prior thereto, there were no Canadian operations and accordingly, the 2012 results are for only two months. The Company added production during 2013 from three 100% Ostracod wells and one 100% Notikewin well. The Ostracod wells represented 74% and 50% of the total Canadian revenue for the Quarter and YTD, respectively.

Royalties

	Three months ended December 31		Year ended December 31	
Canadian $000s	**2013**	**2012**	**2013**	**2012**
Argentina				
Royalties	**161**	208	**801**	609
As % of revenue from Argentina	**13%**	15%	**15%**	15%
Canada				
Royalties	**502**	276	**1,574**	276
As % of revenue from Canada	**12%**	18%	**12%**	18%
Corporate total	**663**	484	**2,375**	885

Neuquén *Basin, Argentina*

Royalty expense in the Quarter declined as a result of reduced oil volumes while royalty expenses for the YTD increased due to higher production volumes.

Canada

Royalty expense consists of royalties paid to provincial governments, freehold landowners and overriding royalty owners. For the Quarter, royalties were 12% (2012 – 18%) of revenues and YTD were 12% (2012 – 18%) of revenues. The decreased royalty rate in 2013 was a result of the Company drilling wells eligible for a reduced crown royalty rate of 5%. Horizontal oil wells receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance).

Operating Costs

Canadian $000s, except per boe	Three months ended December 31 2013	2012	Year ended December 31 2013	2012
Argentina				
Operating costs	**640**	653	**2,807**	1,888
$/boe	**40.14**	32.79	**40.31**	34.81
Canada				
Operating costs	**2,362**	1,088	**6,729**	1,088
$/boe	**23.38**	28.34	**20.58**	28.34
Corporate total	**3,002**	1,741	**9,536**	2,976

Operating costs in Argentina were $40.14 per boe and $40.31 per boe in the Quarter and YTD, respectively, as work continued on the build-out of necessary facility infrastructure on the Coiron Amago block and the optimization of surface fluid handling and gas conservation facilities. Madalena expects to see the operating costs in Argentina decrease on a boe basis in 2014 and into 2015 as the Company executes its multi-well horizontal program to increase oil volumes and overall facility throughput on newly up-graded and constructed infrastructure.

In Canada, operating costs were $23.38 per boe during the Quarter and $20.58 per boe for the YTD. Operating costs for the four Ostracod horizontal wells were $14.54 and $15.23 per boe for the Quarter and YTD, respectively.

Netbacks (1)

Canadian $, boe	Three months ended December 31 2013	2012	Year ended December 31 2013	2012
Argentina				
Revenue	**79.53**	72.19	**75.20**	73.21
Royalties	**(10.11)**	(10.46)	**(11.51)**	(11.22)
Operating expenses	**(40.14)**	(32.79)	**(40.31)**	(34.81)
Netbacks	**29.28**	28.94	**23.38**	27.18
Canada				
Revenue	**43.21**	40.99	**38.90**	40.99
Royalties	**(4.97)**	(7.19)	**(4.81)**	(7.19)
Operating expenses	**(23.38)**	(28.34)	**(20.58)**	(28.34)
Netbacks	**14.86**	5.46	**13.51**	5.46

Corporate total				
Revenue	**48.16**	51.66	**45.28**	59.86
Royalties	**(5.67)**	(8.31)	**(5.99)**	(9.55)
Operating expenses	**(25.67)**	(29.86)	**(24.04)**	(32.13)
Netbacks	**16.82**	13.49	**15.25**	18.18

(1) The term "netback" is a non-GAAP measure and may not be comparable with the calculation of other entities. Netback is calculated as the average unit sales price, less royalties and operating expenses and represents the cash margin for every barrel of oil equivalent sold. The Company uses this measure to analyze operating performance and considers netback a key measure as it demonstrates its profitability relative to current commodity prices.

General and Administration ("G&A") Expenses

	Three months ended December 31		Year ended December 31	
Canadian $000s	**2013**	**2012**	**2013**	**2012**
Argentina	**668**	229	**1,938**	1,615
Canada	**1,017**	1,379	**4,112**	3,287
	1,685	1,608	**6,050**	4,902

The Company currently has three full-time employees in Argentina and seven full-time employees in Canada. The Company's head office is in Canada. The YTD increase in general and administration costs were predominately a result of the establishment of the Canadian operations and severance payments paid to a former officer.

Finance Cost

In Argentina, accretion costs were $15,958 (2012 – $16,816) for the Quarter and $69,431 (2012 – $62,822) YTD. In Canada, accretion costs were $17,000 (2012 - $10,000) for the Quarter and were $68,000 (2012 - $10,000) YTD.

Share-based Compensation

Under the Company's stock option plan, directors, officers, employees and certain consultants are eligible to receive options to acquire common stock of the Company. The exercise price of the granted options is no less than the closing trading price per share on the last day preceding the date of the grant. Total options granted cannot exceed 10% of the issued and outstanding common shares of the Company. Options granted to directors, officers, employees and consultants may vest immediately or over three years on each anniversary of the grant date. Options expire three to five years from the grant date. There are no cash settlement alternatives for employees under the Company's stock option plan.

Share based compensation was $0.5 million in the Quarter (2012 - $0.6 million) and $1.2 million YTD (2012 - $1.9 million).

Depletion and Depreciation

	Three months ended December 31		Year ended December 31	
Canadian $000s, except per boe	**2013**	**2012**	**2013**	**2012**
Argentina	**471**	626	**1,983**	1,218
Canada	**1,696**	505	**4,655**	505
	2,167	1,131	**6,638**	1,723
$/boe	**18.53**	19.40	**16.73**	18.57

In Argentina, depletion and depreciation expense for the Quarter decreased by $155,000 as a result of lower depletion rates and production volumes. YTD depletion and depreciation increased by $765,000 due to higher depletion rates used and increased production. In Canada, depletion and depreciation expense for 2012 was for only two months from November 1 to December 31, 2012.

Impairment

At December 31, 2013, Madalena determined that there were no indications of impairment for its Argentine CGU at Coiron Amargo North. At December 31, 2012, the Company recognized an impairment of $2.5 million related to this CGU. In assessing its Canadian CGU for impairment at December 31, 2013, the Company observed triggers for impairment that included a decrease in the long term forward Canadian natural gas prices as at December 31, 2013, as listed by McDaniel & Associates Consultants Ltd., relative to those estimated at December 31, 2012, reserve revisions on certain of the mature producing assets, increases in operating costs and significant facility upgrades on the Company's older facilities. The Company's testing of its Canadian CGU recoverable value relative to its carrying value revealed an impairment charge of $5.0 million (2012-nil). The impairment test was based on proved plus probable reserves, using a discount rate of 10% and forward commodity price estimates. The impairment test used the following benchmark prices from McDaniel & Associates Consultants Ltd. price forecast, effective January 1, 2014.

Year	WTI (US$/bbl)	AECO - Spot ($/MMBtu)	Exchange Rate ($US/$Cdn)
2014	95.00	4.00	0.95
2015	95.00	4.25	0.95
2016	95.00	4.55	0.95
2017	95.00	4.75	0.95
2018	95.30	5.00	0.95
2019	96.60	5.25	0.95
2020	95.50	5.35	0.95
2021	100.50	5.45	0.95
2022	102.50	5.55	0.95
2023	104.60	5.65	0.95
2024	106.70	5.75	0.95
2025	108.80	5.90	0.95
2026	111.00	6.00	0.95
2027	113.20	6.15	0.95
2028	115.50	6.25	0.95
Thereafter	+2%/yr	+2%/yr	0.95

The Company has recorded an impairment charge of $14.7 million on its Canadian exploration and evaluation assets at December 31, 2013. Included in this impairment charge are all the costs incurred to December 31, 2013 on the three wells described below.

In late 2012, the Company spud a well in an attempt to establish a resource project from horizontal drilling in the Nordegg formation. The well was completed in 2013 and was unsuccessful in establishing commercial reserves. This well was abandoned during the first quarter of 2014.

In late 2013, the Company drilled a vertical exploration well (which qualified for Canadian "CEE" expenses), which was unsuccessful in establishing commercial reserves. The well was also abandoned in the first quarter of 2014.

Also in late 2013, the Company drilled a horizontal step-out Ostracod well. While work continues on the evaluation of this well, the Company does not believe that the costs incurred at December 31, 2013 will be recovered. Accordingly, all costs incurred through December 31, 2013 are included in the impairment charge.

Costs incurred during the first quarter on the two wells that were abandoned (estimated at $0.8 million) will be included in a first quarter 2014 impairment charge. Depending on the outcome of the Ostracod well continuing to be evaluated, an additional impairment charge may be required. Costs incurred to finish the drilling in early 2014 and subsequently complete this well with a multi-stage frac are estimated at $2.0 million, net to the Company.

Income Taxes

In Canada, as at December 31, 2013, the Company has, subject to confirmation by income tax authorities, cumulative income tax deductions of approximately $77 million (2012 - $49 million).

Transactions with Related Parties

A director of the Company is a partner of a law firm that provides legal services to the Company. During the Quarter and YTD, the Company incurred fees of $119,598 (2012 - $110,189) and $551,179 (2012 - $448,531), respectively from this firm for legal fees related to legal matters of which $34,976 (2012 – 10,000) is included in accounts payable and accrued liabilities at December 31, 2013. The costs were expensed in profit and loss.

A director of one of the Company's subsidiaries provides legal and consulting services to the Company. During the Quarter and YTD, the Company incurred fees of $21,942 (2012 - $230,000) and $260,905 (2012 - $444,099), respectively for these services which related to concession extensions and other legal matters, of which $21,942 (2012 -$10,000) was included in accounts payable and accrued liabilities at December 31, 2013. The costs related to the concession extensions were recorded in PP&E and E&E assets and the costs related to other legal matters were expensed in profit and loss.

The transactions arose during the normal course of business and have been recorded at the exchange amounts, which are the amounts agreed upon by the related parties.

Property, Plant & Equipment Additions

	Three months ended December 31		**Year ended December 31**	
Canadian $000s	**2013**	**2012**	**2013**	**2012**
Argentina				
Land	**(2)**	-	**-**	-
Geological and geophysical	**(22)**	-	**3**	-
Drilling and completions	**1,363**	1,222	**3,026**	4,750
Well equipment and facilities	**433**	2	**1,814**	2,399
Other	**(340)**	223	**852**	1,597
Argentina Total	**1,432**	1,447	**5,695**	8,746

Property, Plant & Equipment Additions

Canadian $000s	Three months ended December 31 2013	2012	Year ended December 31 2013	2012
Canada				
Business combination	**-**	16,530	**-**	16,530
Land	**1**	-	**2**	-
Geological and geophysical	**16**	-	**52**	-
Drilling and completions	**(27)**	2,428	**11,990**	2,428
Well equipment and facilities	**1,509**	61	**4,807**	78
Other	**16**	-	**205**	-
Canada total	**1,515**	19,019	**17,056**	19,036
Corporate total	**2,947**	20,466	**22,751**	27,782

For the Quarter, capital expenditures for property plant and equipment were $2.9 million (2012 - $20.5 million) and YTD were $22.8 million (2012 - $27.8 million). In Argentina during 2013, the Company participated in the CAN.xr-2(h) well re-entry which was drilled and completed horizontally in the Sierras Blancas light oil reservoir, the workover of CAN.x-3 well, the completion of the CAN-8 well and the construction of three surface facility components at Coiron Amargo Norte.

Canadian activity during the Quarter was primarily oil facility upgrades at Leaman and construction of oil faciliites for a recently drilled Ostracod well. YTD the Company drilled, completed and tied-in three Ostracod wells in the Paddle River area and completed and tied-in one Notikewin well at Niton.

Exploration and Evaluation Asset Additions

Canadian $000s	Three months ended December 31 2013	2012	Year ended December 31 2013	2012
Argentina				
Land acquisitions	**1,765**	3	**2,899**	580
Geological and geophysical	**74**	180	**1,229**	602
Drilling and completions	**2,694**	393	**4,535**	7,321
Well equipment and facilities	**182**	8	**(74)**	2
Other	**798**	(222)	**725**	1,304
Argentina Total	**5,513**	362	**9,314**	9,809
Canada				
Business combination	**-**	8,455	**-**	8,455
Land acquisitions	**(16)**	11	**150**	11
Geological and geophysical	**-**	-	**10**	2,104
Drilling and completions	**4,588**	2,104	**10,410**	-
Well equipment and facilities	**17**	-	**536**	-
Other	**49**	-	**125**	-
Canada total	**4,638**	10,570	**11,231**	10,570
Corporate total	**10,151**	10,932	**20,545**	20,379

Capital expenditures for exploration and evaluation assets were $10.2 million for the Quarter and $20.5 million YTD compared to $10.9 million and $20.4 million for the respective corresponding periods in 2012. Argentine expenditures were $5.5 million (2012 -$0.4 million) and $9.3 million (2012 - $9.8 million) for the Quarter and YTD, respectively. Canadian expenditures were $4.6 million (2012 – 10.6 million) and $11.2 million (2012 – 10.6 million) for the Quarter and YTD, respectively.

In Argentina, activity during the Quarter included commencement of the drilling of the CAS.x-15 vertical well and the payment of extension fees relating to the Cortadera concession. Additional activity during the year included conducting two 3D seismic programs at Coiron Amargo Sur, extension fee payments relating to the Curamhuele concession, a workover of the CAS.x-1 vertical well in the Vaca Muerta shale, the drilling and casing of the CAS.x-5 well, the completion of the CAS.x-5 well and completion of CAS.x-4 in the Punta Rosada formation.

In Canada, activity during the Quarter included the drilling of wells at West Cove, Paddle River and Greencourt and ongoing completion activity on the Nordegg well which was previously drilled in the Wildwood area. Additional activity during the year focused on drilling and completion activities on the Company's Wildwood Nordegg horizontal well.

FINANCIAL POSITION, LIQUIDITY AND CAPITAL RESOURCES

Liquidity, working capital and shareholders' equity

Canadian $000s	December 31 2013	December 31 2012
Working capital	**8,016**	30,027
Shareholders' equity	**79,003**	92,386

The Company's capital management objective is to have sufficient capital to be able to execute its business plan. The Company manages its capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Company considers its capital structure to include shareholders' equity, existing credit facilities and working capital. The Company may issue shares to fund its capital commitments or utilize other forms of non-dilutive arrangements such as industry farm-ins or financial joint ventures.

At December 31, 2013, the Company had a revolving operating demand loan credit facility with the National Bank of Canada to a maximum of $10 million with interest charged at the bank's prime rate plus 1.0% per annum. Security for this facility is provided by way of a charge over the petroleum and natural gas assets of the Company. The facility includes a working capital ratio covenant, whereby the Company's working capital deficiency (excluding any unrealized hedging gains or losses) may not exceed $10 million. Standby fees associated with the facility are 0.25% per annum on the undrawn portion.

In addition, The Company has an acquisition / development demand loan credit facility with the National Bank of Canada to a maximum of $3 million with interest charged at the bank's prime rate plus 1. 5% per annum.

Both facilities are subject to a periodic review by the bank and the next review is scheduled on or before May 1, 2014. The facilities were unutilized at December 31, 2013.

As the credit facilities are a demand loan, it may be called at any time. Accordingly, there is no assurance that the credit facilities will be renewed when the current scheduled review is completed.

Share capital issued and options granted

Outstanding Share Capital

On July 11, 2013, the Company raised approximately $7.25 million through the issuance of:

i) 11,765,000 common shares issued as CEE "flow-through shares" at a price of $0.34 by way of a "bought deal" private placement; and

ii) 200,000 common shares at a price of $0.31 per share, 4,780,000 common shares issued as CDE "flow-through shares" at a price of $0.32 per share and 4,886,765 common shares issued as CEE "flow-through shares" at a price of $0.34 per share by way of a Private Placement.

iii) Certain directors and officers of the Company acquired an aggregate of 200,000 common shares and 400,000 CEE "flow-through" shares under the non-brokered Private Placement.

A flow-through share liability in the amount of $936,242 was recorded to recognize the difference between the flow-through share price and the price of the common shares. This liability was reduced to $384,847 as at December 31, 2013 as qualifying expenditures were incurred.

On November 21, 2013, the Company issued 5,555,556 common shares, issued as “flow-through shares” (“CDE Flow-Through Shares”) within the meaning of the Income Tax Act (Canada) at a price of $0.54 per CDE Flow-Through Share, for gross proceeds of $3 million pursuant to a Private Placement.

On December 5, 2013, the Company closed a bought deal financing of 19,575,300 common shares at a price of $0.47 per common share, including 2,553,300 common shares issued pursuant to the exercise of the over-allotment option in full by the underwriters, for aggregate gross proceeds of $9.2 million.

In addition, a total of 2,958,700 shares were issued during 2013 pursuant to the exercise of stock options for proceeds of $630,914, of which 200,000 were issued during the Quarter for proceeds of $84,000.

On February 11, 2014, the Company closed a bought deal financing of 32,857,225 common shares at a price of $0.70 per common share, including 4,285,725 common shares issued pursuant to the exercise of the over-allotment option in full by the Underwriters, for aggregate gross proceeds of $23,000,058.

As of April 28, 2014, the Company has 396,885,731 common shares outstanding.

In March 2012, the Company issued 54,000,000 common shares at a price of $1.25 per common share for gross proceeds of $67,500,000.

Financial Instruments

Financial instruments comprise cash and cash equivalents, trade and other receivables, and trade and other payables. Carrying values reflect the current fair value of the Company’s financial instruments due to their short-term to maturity.

Decommissioning Obligations

Decommissioning obligations result from net ownership interests in property, plant and equipment and are a critical accounting estimate. There are significant uncertainties related to settling decommissioning obligations and the impact on the financial statements could be material. The eventual timing of and costs to settle these obligations could differ from current estimates. The main factors that can cause expected decommissioning obligations to change are changes to laws and regulations, construction of new facilities, changes in reserve estimates and reserve lives and changes in technology.

Argentina

The total undiscounted amount of cash flows required to settle its decommissioning obligations is approximately $2.1 million. The majority of the costs are expected to be incurred between 2023 and 2025. An inflation rate of 10.9% was used to calculate the future value of the undiscounted decommissioning obligations. At December 31, 2013, the decommissioning obligations of $0.4 million have been discounted using a discount rate of 17.18%.

Canada
The total undiscounted amount of cash flows required to settle its decommissioning obligations is approximately $5.6 million. The majority of the costs are expected to be incurred between 2018 and 2030. An inflation rate of 2% was used to calculate the future value of the undiscounted decommissioning obligations. At December 31, 2013, the decommissioning obligations of $4.0 million have been discounted using a discount rate ranging from 1.1% to 2.99%.

Contractual Obligations

Development & Exploration commitments

Coiron Amargo Block
The Coiron Amargo block is divided into two regions called Coiron Amargo Norte (northern portion of the block) and Coiron Amargo Sur (southern portion of the block). Coiron Amargo Norte is currently under a 25 year exploitation (development) concession which was approved by the Province of Neuquén in 2012.

In October 2013, following an application and approval process by Madalena and its partners over several months, the exploration period for Coiron Amargo Sur was extended until November 8, 2014 by way of an official decree signed by the Province of Neuquén in Argentina. The remaining work commitments in Coiron Amargo Sur are estimated at approximately USD$ 2.35 million plus VAT (net to Madalena) as of December 31, 2013. After satisfying these remaining work commitments, Madalena has the ability to extend Coiron Amargo Sur through further exploration, evaluation and/or exploitation (development) phases.

Curamhuele Block
In June 2013 the exploration period was extended by way of an official decree signed by the Province of Neuquén until November 8, 2014.

The key zones of interest across the Curamhuele block are the unconventional Vaca Muerta shale, Lower Agrio shale and liquids rich Mulichinco, as well as other conventional formations of interest. To accelerate exploration and development activities in Argentina, the Company continues to assess different opportunities with RBC Capital Markets ("RBC"), Madalena's exclusive advisor related to its Neuquen basin assets, in respect of a possible joint venture partnership or other transaction.

Madalena's remaining share of future work commitments associated with the Curamhuele block as of December 31, 2013 is approximately US$13.8 million plus VAT. After satisfying these remaining work commitments, Madalena expects to either convert certain area(s) of the acreage into an exploitation (development) concession and/or enter into a new exploration period(s) or unconventional evaluation phase, to further explore and appraise the Curamhuele block.

Cortadera Block
On January 15, 2014, the Corporation announced that, on the Cortadera Block, the joint venture partnership consisting of Apache Corporation, Gas y Petroleo del Neuquén SA and Madalena signed an amended contract agreement to formalize a multi-year agreement for the extension of the initial exploration period and inclusion of subsequent exploration periods. Subsequent to that agreement and following an application and approval process, the first exploration period for Cortadera was extended by way of an official decree which was signed by the Province of Neuquén in Argentina. This extension provides the partnership until October 26, 2014 to satisfy the remaining work commitments on the block, which involves the upcoming re-entry work.

Under the amended agreement, and subsequent to conducting the upcoming re-entry work, the partnership at Cortadera has the option to enter into subsequent exploration periods involving a second exploration period extending to October 25, 2018 and a third exploration upon which the partnership has the option to enter into subsequent exploration periods involving a second exploration period extending to October 25, 2021, or extend the Cortadera Block through potential further evaluation and/or exploitation phases.

The decree signed by the Province of Neuquén, as noted above, stipulates that Gas y Petroleo del Neuquén SA, which is the provincial petroleum company within the Province of Neuquén and is a working interest partner in the Cortadera Block, upwardly revised its carried working interest in the block to 15% from the previous 10%, resulting in a proportionate reduction of Madalena's working interest in the block to 37.8% compared to its previous 40% working interest.

Madalena and its new incoming partner (YPF S.A. post the purchase of the Apache subsidiary in Argentina) plan to re-enter the previously drilled CorS.x-1 Vaca Muerta test well to evaluate an up-hole zone of interest in the wellbore targeting the Mulichinco tight sand play. Madalena believes that its share of any work performed is not expected to be significant due to Apache's obligation to pay for the majority of the costs of the anticipated work program.

Flow-through Shares Commitments

During 2013, the Company completed a CEE flow through share financing in the amount of $5.7 million and CDE flow through share financings of $4.5 million. As at December 31, 2013, all of the CDE flow-through funds had been expended and $1.3 million of the CEE flow-through funds had been expended. The Company has until December 31, 2014 to expend the remaining CEE flow through funds in the amount of $4.4 million on qualified expenditures.

The Company had a previous flow-through share commitment of $462,450 to be renounced by December 31, 2013. As at December 31, 2013, all of these funds had been expended.

ANNUAL AND QUARTERLY FINANCIAL RESULTS

Annual Financial Results

As of December 31 Canadian $000s, except shares outstanding	**2013**	2012	2011
Revenues	**17,960**	5,545	2,599
Net loss	**(23,285)**	(8,865)	(16,137)
Total assets	**96,286**	109,016	42,098
Long-term financial liabilities	**385**	62	-
Shareholder equity	**79,003**	92,386	38,802
Net loss per share – basic and diluted	**(0.07)**	(0.03)	(0.07)

Revenues in 2013 increased as a result of the establishment of Canadian operations in late 2012. The Company recorded an impairment charge in 2013 and 2012 of $19.7 million and $2.5 million, respectively, impacting the net loss recognized of $23.3 million and $8.9 million in 2013 and 2012, respectively.

Quarterly Financial Results

Canadian $000s, except per share amount and shares outstanding	Q4 2013	Q3 2013	Q2 2013	Q1 2013
Revenues	**5,633**	4,840	3,877	3,610
Net loss	**(20,527)**	(118)	(320)	(2,320)
Shares outstanding – 000s	**364.0**	338.7	316.8	316.1
Net loss per share – basic and diluted	**(0.06)**	(0.00)	(0.00)	(0.01)

	Q4 2012	Q3 2012	Q2 2012	Q1 2012
Revenues	3,012	1,762	375	397
Net loss	(4,934)	(916)	(1,848)	(1,167)
Shares outstanding ('000s)	314.3	314.3	314.3	314.3
Net loss per share – basic and diluted	(0.02)	(0.0)	(0.01)	(0.0)

The Company's increase in revenues during 2013 can be attributed to increasing oil production in Argentina, its strategic domestic acquisition in the fourth quarter of 2012 and the active drilling program in Canada that added both oil and gas production during 2013.

The Company recorded an impairment charge in Q4-2013 and Q4-2012 of $19.7 million and $2.5 million, respectively, impacting the net loss recognized of $20.4 million and $4.9 million in Q4-2013 and Q4-2012, respectively.

The Company issued 25.3 million shares during the Quarter for gross proceeds of $12.3 million and issued 54 million shares during Q1-2012 for gross proceeds of $67.5 million.

CRITICAL ACCOUNTING JUDGEMENTS, ESTIMATES AND ACCOUNTING POLICIES

For more details regarding the Company's critical accounting judgments, estimates and accounting policies the following should be read in conjunction with the Company's 2013 annual Consolidated Financial Statements.

Management is required to make judgments, estimates and assumptions in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from those estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. The Company's critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further details on the basis of presentation and significant accounting policies can be found in the Company's notes to the Consolidated Financial Statements for the year ended December 31, 2013.

Critical Accounting Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recognized in the Company's annual and interim Consolidated Financial Statements and accompanying notes. On January 1, 2013, as required, the Company adopted the standards related to joint arrangements, consolidations and associates. See discussion below under Changes in Accounting Policies for details. Further information on Management's critical accounting judgments in applying accounting policies can be found in the notes to the Consolidated Financial Statements for the year ended

December 31, 2013.

Critical accounting estimates

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the period in which the estimates are revised. For 2013, there have been no changes to the Company's key sources of estimation uncertainty. Further information on the Company's key sources of estimation uncertainty can be found in the notes to the Consolidated Financial Statements for the year ended December 31, 2013.

Changes in Accounting Policies

As disclosed in the December 31, 2013 Consolidated Financial Statements, the Company adopted, as required, IFRS 10 Consolidated Financial Statements ("IFRS 10"), IFRS 11 Joint Arrangements("IFRS 11"), IFRS 12 Disclosure of Interest in Other Entities ("IFRS 12"), IFRS 13 Fair Value Measurement ("IFRS 13"), as well as the amendments to IAS 1 Presentation of Financial Statements ("IAS 1"), IAS 27 Separate Financial Statements ("IAS 27")and IAS 28 Investments in Associate and Joint Ventures ("IAS 28").

The Company reviewed its consolidation methodology and determined that the adoption of IFRS 10 did not result in a change in the consolidation status of its subsidiaries and investees. The Company performed a comprehensive review of its interests in other entities and identified no interests that would require different accounting treatment under IFRS 11 or disclosures required under IFRS 12. The Company applied IFRS 13 prospectively as required and there has been no change to the Company's methodology for determining fair value for its financial assets and liabilities and as such, the adoption of IFRS 13 did not result in any measurement adjustments as at January 1, 2013. The amendments to IAS 1, IAS 27 and IAS 28 had no impact on the Consolidated Financial Statements.

Future Accounting Pronouncements

There were no new or amended standards issued during the Year ended December 31, 2013 that are applicable to the Company in future periods. A description of standards and interpretations that will be adopted by the Company in future periods can be found in the notes to the annual Consolidated Financial Statements for the year ended December 31, 2013.

RISK MANAGEMENT

The Company's business, prospects, financial condition, results of operation and cash flows, and in some cases its reputation, are impacted by risks that are categorized as financial risks; operational risks; and safety, environmental and regulatory risks.

In Madalena's Annual Information Form for the fiscal year ended December 31, 2013, the Company provided a detailed review of the risks that could affect its financial condition, results of operations or business that could cause actual results to differ materially from those expressed in the Company's forward-looking statements.

The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

Financial Risks

During the three and year ended December 31, 2013, the Company's financial instruments included cash and cash equivalents, trade and other accounts receivable and accounts payable and accrued liabilities. The carrying values of these financial instruments approximate their fair values due to their relatively short periods to maturity.

The Company is exposed to fluctuating market prices for oil and natural gas. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollars, but also global economic events that dictate the levels of supply and demand. Most commodity prices are based on U.S. dollar benchmarks, which result in the Company's realized prices being influenced by the Canadian/U.S. exchange rates. The Company does not currently sell or transact in any foreign currency and has no foreign exchange risk management contracts outstanding.

The Company mitigates its credit risk associated with cash by holding the cash and cash equivalents in accounts with a high credit quality financial institution. As the Company has cash balances and no debt, it is not exposed to interest rate risks arising from fluctuating interest rates. The Company's assets, liabilities and operations are denominated in Canadian dollars mitigating foreign exchange risk.

In Argentina, the majority of the Company's oil production is sold to the Argentina subsidiaries of major international oil and gas companies. In Canada, receivables from oil and natural gas marketers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company historically has not experienced any collection issues with its oil and natural gas marketers.

The Company does not anticipate any default as it transacts with creditworthy customers and management does not expect any losses from non-performance by these customers. As such a provision for doubtful accounts has not been recorded at December 31, 2013 and December 31, 2012.

Operational Risks

The Company is exposed to operational risks being the risk of loss or lost opportunity resulting from reserve replacement and capital and operating activities. The Company's ability to operate, generate cash flows, complete projects, and add reserves is dependent on financial risks, including commodity prices mentioned above, continued market demand for its products and other risk factors outside of its control, which include: general business and market conditions; economic recessions and financial market turmoil; the ability to secure and maintain cost effective financing for its commitments; environmental and regulatory matters; unexpected cost increases; royalties; taxes; the availability of drilling and other equipment; the ability to access lands; weather; the availability of processing capacity; the availability and proximity of pipeline capacity; technology failures; accidents; the availability of skilled labour; and reservoir quality.

If the Company fails to acquire or find additional oil or natural gas reserves, its reserves and production will decline materially from their current levels and, therefore, its cash flows are highly dependent upon successfully exploiting current reserves and acquiring, discovering or developing additional reserves.

To mitigate these risks, as part of the capital approval process, the Company's projects are evaluated on a fully risked basis, including geological risk and engineering risk. When making operating and investing decisions, the Company's decision model seeks to optimize investments focused on project returns, long-term value creation, and risk mitigation.

Foreign Operations

Prior to the acquisition of Online on November 1, 2012 all of the Company's oil and gas operations were in Argentina. A number of risks are associated with conducting foreign operations over which the Company has no control, including currency instability, potential and actual civil disturbances, restriction of funds movement outside of these countries, the ability of joint venture partners to fund their obligations, changes of laws affecting foreign ownership and existing contracts, crude oil and natural gas price and production regulation, royalty rates, potential expropriation of property without fair compensation, retroactive tax changes and possible interruption of oil deliveries.

Expiration of licences and leases

The Company's properties in Argentina are held in the form of licences and leases and working interests in licences and leases. If the Company or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Company's licences or leases or the working interests relating to a licence or lease may result in an impairment of the costs incurred with respect to the block.

In response to declining oil and gas production volumes in Argentina, the federal and various provincial governments in Argentina are calling for oil and gas companies operating in the country to increase investment. Any federal changes to the licencing regime or changes to the provincial licencing regime in Neuquén Province, Argentina where the Company's acreage is located could have a material adverse effect on the Company.

Safety, Environmental and Regulatory Risks

The Company's business is subject to all of the operating risks normally associated with the exploration for, development of and production of natural gas and liquids. These risks are managed by executing policies and standards that are designed to comply with or exceed government regulations and industry standards.

Substantial capital requirements

In order to completely exploit its existing properties and create future growth, the Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. In addition, uncertain levels of near term industry activity and uncertain global markets may impair the Company's ability to access capital. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business financial condition, results of operations and prospects.

For further risks related to the Company, please see Madalena's AIF for the year ended December 31, 2013 which is filed on SEDAR.

ADVISORY

Forward Looking Statements

This MD&A may include forward-looking statements including opinions, assumptions, estimates and management's assessment of the Company's assets, future plans and operations, expected depletion, depreciation and accretion expenses, expectations as to the taxability of the Company, the quality of the Company's assets and planned capital expenditures and the timing and funding thereof. When used in this document, the words "anticipate," "believe," "estimate," "expect," "intent," "may," "project," "plan", "should" and similar expressions are intended to be among the statements that identify forward-looking statements. Forward-looking statements are subject to a wide range of risks and uncertainties, and although the Company believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will be realized. Any number of important factors could cause actual results to differ materially from those in the forward-looking statements including, but not limited to, risks associated with petroleum and natural gas exploration, development, exploitation, production, marketing and transportation, the volatility of petroleum and natural gas prices, currency fluctuations, the ability to implement corporate strategies, the state of domestic capital markets, the ability to obtain financing, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, changes in petroleum and natural gas acquisition and drilling programs, delays resulting from inability to obtain required regulatory approvals, delays resulting from inability to obtain drilling rigs and other services, labour supply risks, environmental risks, competition from other producers, imprecision of reserve estimates, changes in general economic conditions, ability to execute farm-in and farm-out opportunities, and other factors, all of which are more fully described from time to time in the reports and filings made by the Company with securities regulatory authorities.

Statements relating to “reserves” or “resources” are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described can be profitably produced in the future.

The forward looking statements contained in this MD&A are expressly qualified by this cautionary statement. Readers are cautioned not to place undue reliance on forward-looking statements, as no assurances can be given as to future results, levels of activity or achievements. Except as required by applicable securities laws, the Company does not undertake any obligation to publicly update or revise any forward-looking statements.

Reserves, Resources and Other Oil and Gas Disclosure

Any references in this MD&A to test rates, flow rates, initial and/or final raw test or production rates, early production, test volumes behind pipe and/or "flush" production rates are useful in confirming the presence of hydrocarbons, however, such rates are not necessarily indicative of long-term performance or of ultimate recovery. Such rates may also include recovered "load" fluids used in well completion stimulation. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for Madalena. In addition, the Vaca Muerta shale is an unconventional resource play which may be subject to high initial decline rates.

<u>Notes To Disclosure of Resources:</u>

(1) "Total Petroleum Initially In Place" means DPIIP + UPIIP. When calculating DPIIP, there is no material production or reserves associated with these properties. Contingent resources is the only category of DPIIP that has been categorized as recoverable. Prospective resources is the only category of UPIIP that has been categorized as recoverable. There is no certainty that it will be commercially viable to produce any portion of the contingent resources referred to in the tables above. There is no certainty that any portion of the prospective resources referred to in the tables above will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of these resources.

(2) Certain volumes are arithmetic sums of multiple estimates of contingent & prospective resources, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of resources and appreciate the differing probabilities of recovery associated with each class as explained herein. Details on the categories that comprise these calculations are in the tables that follow.

Coiron Amargo Discovered Petroleum Initially In Place [1] (net to Madalena)
Oil, NGLs and Natural Gas at December 31, 2012

	Oil & NGLs (MMbbl)			Natural Gas (Tcf)			Oil & NGLs + Natural Gas (MMboe)		
	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10
Vaca Muerta Shale	242.6	244.4	246.2	0.077	0.077	0.078	255.4	257.4	259.2

Note:

(1) When calculating DPIIP, there is no material production or reserves associated with these properties. All DPIIP, other than contingent resources, has been categorized as unrecoverable. There is no certainty that it will be commercially viable to produce any portion of the resources referred to in the table above.

(2) These volumes are arithmetic sums of multiple estimates, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of resources and appreciate the differing probabilities of recovery associated with each class as explained herein.

Coiron Amargo Contingent Resources[1] (net to Madalena)
Oil, NGLs and Natural Gas at December 31, 2012

	Oil & NGLs (MMbbl)			Natural Gas (Tcf)			Oil & NGLs + Natural Gas (MMboe)		
	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10
Vaca Muerta Shale	5.8	18.3	30.6	0.002	0.006	0.01	6.1	19.3	32.2

Notes:

(1) There is no certainty that it will be commercially viable to produce any portion of the resources referred to in the table above.

Coiron Amargo Undiscovered Petroleum Initially In Place [1] (net to Madalena)
Oil, NGLs and Natural Gas at December 31, 2012

	Oil & NGLs (MMbbl)			Natural Gas (Tcf)			Oil & NGLs + Natural Gas (MMboe)		
	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10
Vaca Muerta Shale	2,687.8	2,717.5	2,747.5	0.851	0.861	0.870	2,829.7	2,860.9	2,892.5

Notes:

(1) Prospective resources is the only category of UPIIP that has been categorized as recoverable. There is no certainty that any portion of the resources referred to in the table above will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of these resources.

(2) These volumes are arithmetic sums of multiple estimates, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of resources and appreciate the differing probabilities of recovery associated with each class as explained herein.

Coiron Amargo Prospective Resources[1] (net to Madalena)
Oil, NGLs and Natural Gas at December 31, 2012

	Oil & NGLs (MMbbl)			Natural Gas (Tcf)			Oil & NGLs + Natural Gas (MMboe)		
	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10
Vaca Muerta Shale	122.7	249.7	377.2	0.039	0.079	0.119	129.2	262.9	397.1

Notes:

(1) Prospective resources is the only category of UPIIP that has been categorized as recoverable. There is no certainty that any portion of the resources referred to in the table above will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of these resources.

Curamhuele Undiscovered Petroleum Initially In Place [1] (net to Madalena)
Oil, NGLs and Natural Gas at December 31, 2012

	Oil & NGLs (MMbbl)			Natural Gas (Tcf)			Oil & NGLs + Natural Gas (MMboe)		
	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10
Lower Agrio Shale	3,835.7	4,763.4	5,834.0	2.777	3.955	5.443	4,298.4	5,422.5	6,741.2
Vaca Muerta Shale	7,884.8	9,642.9	11,762.2	17.405	52.017	90.208	10,785.7	18,312.3	26,796.9
Total	11,720.5	14,406.2	17,596.2	20.182	55.971	95.651	15,084.2	23,734.8	33,538.1

Notes:

(1) Prospective resources is the only category of UPIIP that has been categorized as recoverable. There is no certainty that any portion of the resources referred to in the table above will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of these resources.

(2) These volumes are arithmetic sums of multiple estimates, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of resources and appreciate the

differing probabilities of recovery associated with each class as explained herein.

Curamhuele Prospective Resources[1] (net to Madalena)
Oil, NGLs and Natural Gas at December 31, 2012

	Oil & NGLs (MMbbl)			Natural Gas (Tcf)			Oil & NGLs + Natural Gas (MMboe)		
	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10
Lower Agrio Shale	86.1	328.6	596.2	0.070	0.266	0.524	97.8	373.0	683.5
Vaca Muerta Shale	174.7	667.4	1,207.4	0.663	2.942	8.096	285.2	1,157.6	2,556.7
Total	260.8	996.0	1,803.6	0.733	3.208	8.620	382.9	1,530.6	3,240.2

Notes:
(1) There is no certainty that any portion of the resources referred to in the table above will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of these resources.

Cortadera Undiscovered Petroleum Initially In Place[1] (net to Madalena)
Oil, NGLs and Natural Gas at December 31, 2012

	Oil & NGLs (MMbbl)			Natural Gas (Tcf)			Oil & NGLs + Natural Gas (MMboe)		
	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10
Basal Quintuco	46.8	108.8	184.8	16.234	22.706	29.003	2,752.4	3,893.1	5,018.6
Vaca Muerta Shale	52.8	118.0	184.4	22.277	23.656	25.082	3,765.6	4,060.6	4,364.7
Total	99.6	226.8	369.2	38.510	46.362	54.085	6,518.0	7,953.7	9,383.3

Notes:
(1) Prospective resources is the only category of UPIIP that has been categorized as recoverable. There is no certainty that any portion of the resources referred to in the table above will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of these resources.

(2) These volumes are arithmetic sums of multiple estimates, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of resources and appreciate the differing probabilities of recovery associated with each class as explained herein.

Cortadera Prospective Resources[1] (net to Madalena)
Oil, NGLs and Natural Gas at December 31, 2012

	Oil & NGLs (MMbbl)			Natural Gas (Tcf)			Oil & NGLs + Natural Gas (MMboe)		
	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10	Low Estimate P90	Best Estimate P50	High Estimate P10
Basal Quintuco	5.6	14.0	27.2	1.745	2.932	4.569	296.5	502.6	788.7
Vaca Muerta Shale	6.4	14.8	27.6	1.958	3.189	4.428	332.7	546.3	765.6
Total	12.0	28.8	54.8	3.703	6.121	8.997	629.2	1,048.9	1,554.3

Notes:
(1) Prospective resources is the only category of UPIIP that has been categorized as recoverable. There is no certainty that any portion of the resources referred to in the table above will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of these resources.

DEFINITIONS:

"Contingent resources"

Definition: Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

"Discovered petroleum initially-in-place" or "discovered resources" or "DPIIP"

Definition: That quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially-in-place includes production, reserves and contingent resources; the remainder is unrecoverable.

"Prospective resources"

Definition: Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development.

"Total petroleum initially-in-place", "total resources" or "TPIIP"

Definition: That quantity of petroleum that is estimated to exist originally in naturally occurring accumulations; equal to DPIIP plus UPIIP. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered.

"Undiscovered petroleum initially-in-place", "undiscovered resources" or "UPIIP"

Definition: That quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially-in-place is referred to as prospective resources; the remainder is unrecoverable.

Numerical Amounts

The reporting and the measurement currency is the Canadian dollar. Natural gas reserves and volumes are converted to barrels of oil equivalent (boe) on the basis of six thousand cubic feet (mcf) of gas to one barrel (bbl) of oil. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

This MD&A uses the term “netback” which is a term that does not have standardized meanings under GAAP and this non-GAAP measurement may not be comparable with the calculation of other entities. The Company uses this measure to analyze operating performance.

The term “netback”, which is calculated as the average unit sales price, less royalties and operating expenses, represents the cash margin for every barrel of oil equivalent sold. The Company considers this a key measure as it demonstrates its profitability relative to current commodity prices. This term does not have any standardized meaning prescribed by GAAP and, therefore, might not be comparable with the calculation of a similar measure for other companies.

Barrels of Oil Equivalent

All calculations converting natural gas to barrels of oil equivalent ("boe") have been made using a conversion ratio of six thousand cubic feet (six "Mcf") of natural gas to one barrel of oil, unless otherwise stated. The use of boe may be misleading, particularly if used in isolation, as the conversion ratio of six Mcf of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Analogous Information

Certain information in this document may constitute "analogous information" as defined in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activitie*s ("NI 51-101"), including, but not limited to, information relating to areas, assets, wells and/or operations that are in geographical proximity to or believed to be on-trend with lands held by Madalena. Such information has been obtained from public sources, government sources, regulatory agencies or other industry participants. Management of Madalena believes the information may be relevant to help define the reservoir characteristics in which Madalena may hold an interest and such information has been presented to help demonstrate the basis for Madalena's business plans and strategies.

However, such analogous information has not been prepared in accordance with NI 51-101 and the Canadian Oil and Gas Evaluation Handbook and Madalena is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor. Madalena has no way of verifying the accuracy of such information. There is no certainty that the results of the analogous information or inferred thereby will be achieved by Madalena and such information should not be construed as an estimate of future production levels or the actual characteristics and quality of Madalena's assets. Such information is also not an estimate of the reserves or resources attributable to lands held or to be held by Madalena and there is no certainty that such information will prove to be analogous in the future. The reader is cautioned that the data relied upon by Madalena may be in error and/or may not be analogous to such lands to be held by Madalena.

ABBREVIATIONS

The following is a summary of the abbreviations used in this MD&A:

Oil and Natural Gas Liquids		**Natural Gas**	
Bbl	barrel	Mcf	thousand cubic feet
Bbls/d	barrels per day		
NGLs	Natural gas liquids		

boe	barrel of oil equivalent
boe/d	barrel of oil equivalent per day