ANTRIM ENERGY INC.

Annual Information Form

Year Ended

December 31, 2012

March 26, 2013

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ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
Stb	stock tank barrel	MMcf	million cubic feet
Mbbl	thousands of barrels	Mcfpd	thousand cubic feet per day
bbl/d	barrels per day	MMcfpd	million cubic feet per day
NGL	natural gas liquids	m^3	cubic metres
LPG	liquefied petroleum gas	m^3/d	cubic metres per day

Other	
boe (1)	barrel of oil equivalent of crude oil and natural gas on the basis of 1 bbl of crude oil for 6 Mcf of natural gas
boe/d (1)	barrel of oil equivalent per day
bopd	barrel of oil per day
WTI	West Texas Intermediate
m	metres
km	kilometres
km^2	square kilometres

Note:

(1) boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In this Annual Information Form, all dollar amounts are expressed in United States ("**US**") dollars and all references to "dollars" or to "$" are to US dollars, all references to "Cdn $" are to Canadian dollars and all references to "£" are to British pounds sterling, unless otherwise specified.

CONVERSION

The following table sets forth certain standard conversions from Standard Imperial Units to the International System of Units (or metric units) or vice versa.

To Convert From	To	Multiply By	To Convert From	To	Multiply By
Mcf	Cubic metres	28.317	Feet	Metres	0.305
Cubic metres	Cubic feet	35.315	Metres	Feet	3.281
Cubic metres	Barrels	6.289	Miles	Kilometres	1.609
Tonnes – butane	Barrels	12.45	Kilometres	Miles	0.621
Tonnes – propane	Barrels	10.94			

Forward Looking Statements

This AIF and any documents incorporated by reference herein contain certain forward-looking statements and forward-looking information which are based on Antrim's internal reasonable expectations, estimates, projections, assumptions and beliefs as at the date of such statements or information. Forward-looking statements often, but not always, are identified by the use of words such as “seek”, “anticipate”, “believe”, “plan”, “estimate”, “expect”, “targeting”, “forecast”, “achieve” and “intend” and statements that an event or result “may”, “will”, “should”, “could” or “might” occur or be achieved and other similar expressions. These statements are not guarantees of future performance and involve known and unknown risks, uncertainties, assumptions and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements and information. Antrim believes that the expectations reflected in those forward-looking statements and information are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements and information included in this AIF and any documents incorporated by reference herein should not be unduly relied upon. Such forward-looking statements and information speak only as of the date of this AIF or the particular document incorporated by reference herein and Antrim does not undertake any obligation to publicly update or revise any forward-looking statements or information, except as required by applicable laws.

In particular, this AIF and any documents incorporated by reference herein, contain specific forward-looking statements and information pertaining to the quality of and future net revenues from Antrim's reserves of oil, natural gas liquids (“**NGL**”) and natural gas production levels. This AIF may also contain specific forward-looking statements and information pertaining to commodity prices, foreign currency exchange rates and interest rates, capital expenditure programs and other expenditures, supply and demand for oil, NGL’s and natural gas, expectations regarding Antrim's ability to raise capital, to continually add to reserves through acquisitions and development, the schedules and timing of certain projects, Antrim's strategy for growth, Antrim's future operating and financial results, treatment under governmental and other regulatory regimes and tax, environmental and other laws.

With respect to forward-looking statements contained in this AIF and any documents incorporated by reference herein, Antrim has made assumptions regarding its ability to obtain additional drilling rigs and other equipment in a timely manner, obtain regulatory approvals, future oil and natural gas production levels from Antrim's properties and the price obtained from the sales of such production, the level of future capital expenditure required to exploit and develop reserves, the ability of Antrim’s partners to meet their commitments as they relate to Antrim and Antrim’s reliance on industry partners for the development of some of its properties, Antrim’s ability to obtain financing, the general stability of the economic and political environment in which Antrim operates and the future of oil and natural gas pricing. In respect to these assumptions, the reader is cautioned that assumptions used in the preparation of such information may prove to be incorrect.

Antrim's actual results could differ materially from those anticipated in these forward-looking statements and information as a result of assumptions proving inaccurate and of both known and unknown risks, including risks associated with the exploration for and development of oil and natural gas reserves, operational risks and liabilities that are not covered by insurance, volatility in market prices for oil, NGLs and natural gas, changes or fluctuations in oil, NGLs and natural gas production levels, changes in foreign currency exchange rates and interest rates, the ability of Antrim to fund its substantial capital requirements and operations, the obligations of Antrim to repay its obligations under the payment swap and Antrim's reliance on industry partners for the development of some of its properties, risks associated with ensuring title to Antrim’s properties, liabilities and unexpected events inherent in oil and gas operations, including geological, technical, drilling and processing problems, the risk of adverse results from litigation, the accuracy of oil and gas reserve estimates and estimated production levels as they are affected by the Antrim’s exploration and development drilling and estimated decline rates, in particular the production rates at the Causeway and Cormorant East fields and future production rates the West Causeway field in the UK North Sea. Additional risks include the ability to effectively compete for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel, incorrect assessments of the value of acquisitions, Antrim's success at acquisition, exploitation and development of reserves, changes in general economic, market and business conditions in Canada, North America, the United Kingdom, Europe and worldwide, actions by governmental or regulatory authorities including changes in income tax laws or changes in tax laws, royalty rates and incentive programs relating to the oil and gas industry and more specifically, changes in environmental or other legislation applicable to Antrim's operations, and Antrim's ability to comply with current and future environmental and other laws, adverse regulatory rulings, order and decisions and risks associated with the nature of the Common Shares.

Statements relating to "resources" are deemed to be forward-looking statements, as they involve the implied assessment based on certain estimates and assumptions, that the reserves described can be profitably produced in the future. The estimates of remaining recoverable prospective resources have been risked for chance of discovery, but have not been risked for chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development.

Many of these risk factors, other specific risks, uncertainties and material assumptions are discussed in further detail throughout the AIF and in Antrim's management discussion and analysis for the year ended December 31, 2012. Readers are specifically referred to the risk factors described in this AIF under "Risk Factors" and in other documents Antrim files from time to time with securities regulatory authorities. Copies of these documents are available without charge from Antrim or electronically on the internet on Antrim's SEDAR profile at www.sedar.com. Readers are cautioned that this list of risk factors should not be construed as exhaustive.

The calculation of barrels of oil equivalent ("boe") is based on a conversion rate of six thousand cubic feet of natural gas ("mcf") to one barrel of crude oil ("bbl"). Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead (as defined below).

In accordance with AIM guidelines, Mr. Kerry Fulton, P. Eng and Vice President, Operations for Antrim, is the qualified person that has reviewed the technical information contained in this AIF. Mr. Fulton has over 30 years operating experience in the upstream oil and gas industry.

THE COMPANY

General

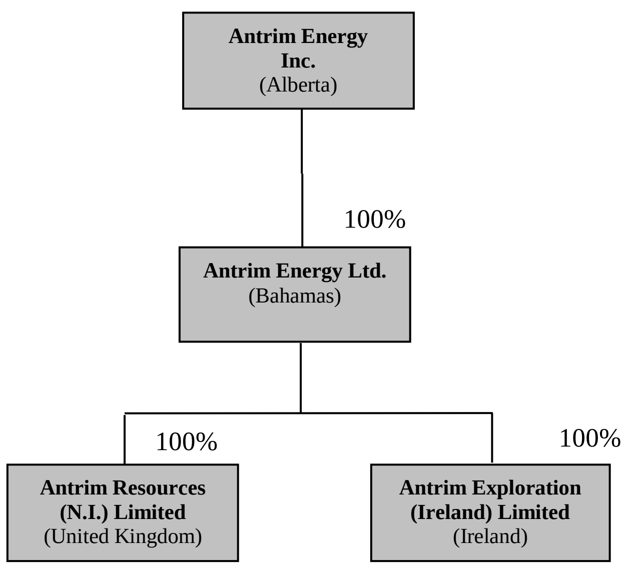
Antrim Energy Inc. ("**Antrim**" or the "**Company**") is a company engaged in the business of oil and natural gas acquisition, exploration, development and production in international locations. Antrim was formed on the amalgamation (the "**Amalgamation**") of Antrim International Inc. and Netherfield Energy Corporation pursuant to Articles of Arrangement and Articles of Amalgamation filed under the *Business Corporations Act (Alberta)* on September 29, 1999. On October 12, 1999, the post-Amalgamation common shares ("**Common Shares**") of Antrim began trading on the Alberta Stock Exchange, a predecessor to the Canadian Venture Exchange ("**CDNX**") and now the TSX Venture Exchange. On February 2, 2001, Antrim began trading on The Toronto Stock Exchange (the "**TSX**") and subsequently delisted its securities from the TSX Venture Exchange. On July 31, 2003, the Common Shares were admitted for trading on the Alternative Investment Market operated by the London Stock Exchange plc ("**AIM**").

Antrim's principal properties are located in the United Kingdom. See "Business of Antrim" and "Statement of Reserves Data and Other Oil and Gas Information - Properties".

Antrim's principal business and head office is located at Suite 610, 301-8th Avenue S.W., Calgary, Alberta, Canada, T2P 1C5. Antrim's registered office is located at 1600, 333 – 7th Avenue S.W., Calgary, Alberta, Canada, T2P 2Z1.

Intercorporate Relationships

Antrim has three wholly-owned subsidiaries. The following chart sets forth the corporate structure of Antrim. The jurisdiction of incorporation is indicated in parentheses.



GENERAL DEVELOPMENT OF THE BUSINESS

Since incorporation, Antrim has focused on international oil and gas exploration and development. Antrim's current principal oil and gas interests are located in the United Kingdom.

United Kingdom

P077 Block 21/28a – Fyne, Dandy and Crinan

Antrim acquired a 75% working interest in UKCS Licence P077 Block 21/28a (the **"Fyne Licence"**) in the Central North Sea in November 2006 for an initial sum of \$8 million, and an additional \$10 million to be paid on approval of a field development plan ("**FDP**"). The licence, a 2nd Round licence, contains the Fyne Field, the Dandy Field and the Crinan Field (previously referred to as "Area 4"). These three fields are Eocene Tay Sandstone pools which were delineated with eight wells drilled from 1971 to 1998.

In 2007 and 2008, Antrim acquired 70 km^2 of 3D seismic and drilled five penetrations in the Fyne Field: well 21/28a-9, plus sidetracks 21/28a-9Y and 21/28a-9Z, and well 21/28a-10, plus sidetrack 21/28a-10Z.

In October 2010, Antrim signed an Earn In Agreement ("**EIA**") with Premier Oil UK Limited ("**Premier**") to jointly investigate development options for the Fyne area. Under the terms of the EIA, Premier paid an initial consideration of \$2 million to Antrim for an option to acquire a 39.9% interest in the Fyne Licence. Premier subsequently exercised their option to acquire the interest in the licence by drilling an appraisal well in the eastern portion of the Fyne Field, and was appointed operator. Antrim was carried for drilling costs associated with its remaining 35.1% interest in the Fyne Licence.

The original (2nd Round) Fyne Licence was due to expire on November 25, 2011. In March 2011, the UK Department of Energy and Climate Change ("**DECC**") agreed to a three-year extension to November 25, 2014. As part of the renewal process, Antrim identified the Fyne Field, the Dandy Field and the Crinan Field as Prospective Areas, a total of 70.2 km^2 of the total 101.2 km^2 pre-renewal licence area. The remaining 30 km^2, which did not contain any production potential in the view of the Company, was relinquished effective November 21, 2010. Under the terms of the renewal, DECC required that a well be drilled in the Fyne Prospective Area and a FDP for the Fyne Field be submitted by June 25, 2012 (subsequently extended to March 29, 2013).

In January and February 2012, Premier and the Company drilled the East Fyne appraisal well 21/28a-11, designed to de-risk the eastern extent of the Fyne Field. On February 6, 2012, the Company announced that the thickness of the oil bearing sand was at the lower end of Antrim's estimate, and the well had been plugged and abandoned. The less than expected results of the East Fyne well had a material impact on the estimated reserves and net present values associated with the Fyne Field. The carrying value of the Fyne Licence was written down 100% to a \$nil value with the Company incurring a \$60.1 million impairment charge in the first quarter of 2012.

In April 2012, Antrim announced that, under the terms of the Joint Operating Agreement (the "JOA") in respect of the Fyne Licence, Antrim would regain 39.9% working interest, associated reserves and operatorship in the licence from Premier at no cost, followed in May 2012 by an additional 25% working interest and associated reserves from First Oil Expro Limited ("**First Oil**") at no cost. As a result, Antrim's working interest in the Fyne Licence increased to 100%. Completion of the transaction to effect this increase in Antrim's working interest occurred in the first quarter of 2013.

In November 2012, Antrim announced a Heads of Terms agreement had been signed with Hummingbird Production Limited, a subsidiary of Teekay Corporation, for an option to lease the "Hummingbird Spirit" Floating Production, Storage and Offloading vessel ("**FPSO**") for the development of the Fyne Field.

On March 26, 2013 the Company discontinued development of the Fyne Field. Until very recently, estimated costs indicated that the planned Fyne development passed the Company's economic threshold and contingent on timing of the redeployment of the FPSO from its current location was on track for a late 2014 start-up. However, projected capital costs have increased substantially, and in the Company's view now make the project uneconomic.

P1383 Block 211/23d and P201 Block 211/22a South East Area – Causeway, Fionn and West Causeway

Antrim acquired a 79% interest in UKCS fourth round Licence P201 Block 211/22a South East Area in a series of transactions in 2004 and 2005. Antrim acquired 100% interest in Licence P1383 Block 211/23d in in the 23rd Round in 2005. In 2006, through a series of farmout transactions and exercise of rights of another company under an area of mutual interest agreement, Antrim's interest was reduced to 65.5% in both licences. The licences contain the Causeway Field (formerly referred to as "East Causeway" and "Far East Causeway"), the Fionn Field (formerly referred to as "Central Causeway") and the West Causeway Field. Existing exploration wells drilled in 1984 and 1992 confirmed a series of fault-bounded, staircase like structures extending northeast from Block 211/22a South East Area onto Block 211/23d containing oil-bearing reservoirs in the Jurassic Brent interval.

In January 2006, Antrim was appointed as exploration operator for both Block 211/22a South East Area and Block 211/23d. From 2006 to 2008, Antrim drilled six wells on the Causeway structure. Three wells were tested, the most prolific of which was well 211/23d-17Z which tested oil at a peak rate of 14,500 barrels of oil per day ("**bopd**") from the Brent Tarbert and Etive formations. All six wells were suspended for future use as production or water injection wells.

A FDP was submitted to DECC in December 2008 with a phased programme starting with Causeway. That FDP submission was suspended while awaiting further progress on an export route.

Effective December 8, 2009, 46.5 km^2 of the total 96.3 km^2 of the original Licence P1383 Block 211/23d was relinquished, as required after the initial four year term, and the licence extended into a second four year term. The relinquished area was considered to have the lowest potential on the block, and does not include any of the delineated Causeway Field.

In October 2011, Antrim completed a conditional letter agreement ("**CLA**") with Valiant Petroleum plc ("**Valiant**") to sell a 30% interest in both licences. As part of the CLA, Antrim received a carry of up to $21.75 million towards its remaining 35.5% interest share of development costs of the Causeway Field. Antrim transferred operatorship of the licences to Valiant and retained a 35.5% working interest in the licences. To compensate Valiant for the tax benefit that Antrim would receive from the $21.75 million paid by Valiant, a Differential Lifting Agreement was executed such that Antrim's 35.5 % share of production from Causeway would be reduced to 29.25% until the sum of that reduced production reached $8.928 million.

In November 2011, DECC agreed to separate field designations for the Causeway Field and the Fionn Field.

An export route was negotiated with TAQA Bratani Limited ("**TAQA**") for use of the North Cormorant production platform. Antrim and Valiant approved a phased development scheme for Causeway. The Causeway FDP was approved by DECC in December 2011.

Causeway production commenced in early November, 2012, with gross production rates of approximately 4,500 bopd (net 1,600 bopd to Antrim) from a single production well. Initial production rates were impacted by longer-than-anticipated clean-up and commissioning due to the long horizontal nature of the well.

Rig operations commenced in January 2013 to complete the water injector for the Causeway Field and were completed in February 2013. Anticipated startup of the downhole electrical submersible pump ("ESP") will follow completion of topside modifications on the North Cormorant production platform, and is scheduled for the second half of 2013. The recently completed water injection well is expected to commence operation in 2014, with a possibility of it being accelerated to the second half of 2013.

In 2012, subsea installations for the Fionn Field were done at the same time as the Causeway Field. Antrim's share of costs for Fionn was carried by Valiant. Antrim retained an option to opt out of the Fionn Field development once three months of production had occurred from the Causeway Field. In August 2012, DECC approved the FDP for the Fionn Field.

Projected costs associated with the development of the Fionn Field increased to the extent that the project no longer met Antrim's economic criteria. In January 2013, Antrim therefore elected to opt out of the Fionn Field development. Subject to all necessary approvals from DECC, Antrim will withdraw from the Fionn Field subarea and retain no further liabilities, including no decommissioning or well abandonment liabilities for the three suspended wells in the Fionn Field. Antrim remains a 35.5% interest owner of the remainder of P201 Block 211/22a South East Area, including the West Causeway Field.

Licence P1383 Block 211/23d will complete its second four year term in December, 2013. Any area not identified as a "Producing Part" or a "Prospective Area" will be relinquished at that time. Currently, the Company does not consider any area within the licence other than the Causeway Field to have commercial prospectivity.

P201 Block 211/22a Kerloch Area and P201 Block 211/22a Contender Area – Kerloch and Cormorant East

Antrim acquired a 21% working interest in UKCS Licence P201 Block 211/22a North West Area in 2005 as part of a division of Block 211/22a into two sub areas. The licence included several prospects, including the Clachnaben and Kerloch Jurassic Brent prospects in the northwestern part of the block.

The Clachnaben prospect was drilled in 2005 and subsequently plugged and abandoned after drilling to the primary target. The Kerloch prospect was drilled in 2007, and discovered a small oil pool in the Brent Ness formation. The Kerloch well was suspended to allow potential re-entry and future use.

In August 2011, Antrim signed a farm-out agreement with TAQA whereby TAQA agreed to drill an exploration well in the central west part of the block to earn an interest in the licence. In September 2011, as part of the transaction, Block 211/22a North West Area was further subdivided into two sub-areas: Block 211/22a Kerloch Area in the north and Block 211/22a Contender Area in the south. By committing to drill an exploration well in the south, TAQA earned a 60% interest in the Contender Area, reducing Antrim's interest to 8.4%. Upon drilling the exploration well, TAQA earned 35% interest in the Kerloch Area, reducing Antrim's interest to 13.65%. TAQA assumed operatorship of the Contender Area.

In October 2012, TAQA drilled exploration well 211/21-N94 from the North Cormorant production platform. Drilled to a total drilling depth of 16,903 feet (11,550 feet true vertical depth subsea), the well encountered 73 feet of net oil pay in the Brent Tarbert with greater than expected porosity and hydrocarbon saturation with no water bearing sands identified. The discovery was named the Cormorant East Field. A FDP was approved by DECC in November 2012, calling for the field to initially be produced under primary depletion, but with the potential to install a water injection scheme at a later date.

Completion and tie-in of the Cormorant East well was finalized in January 2013. The initial production rate was approximately 5,500 bopd (net Antrim approximately 460 bopd), with no water. Production is processed at the North Cormorant platform before being exported to the Sullom Voe terminal for sale. Under terms of the farmin agreement with TAQA, Antrim's share of the drilling and completion costs of the exploration well was carried by TAQA. Antrim's share of the completion and tie-in costs will be recovered by TAQA from Antrim's share of initial production revenue.

P1875 Block 21/29d – Erne and Corrib

Antrim acquired 100% interest in UKCS licence P1875 Block 21/29d in January 2011 in the 26th Round. The block contained the Erne Eocene Tay prospect. The required work programme for the licence included seismic purchase and reprocessing. A drill or drop decision was required by the second anniversary of the licence, January 2013. A decision to drill would require that the well be drilled by the end of the initial term in January 2015.

Antrim completed the seismic component of the workscope and identified Erne as the most promising prospect. In July 2011, under terms of the EIA signed in October 2010 to jointly investigate development options for the Fyne area, Premier exercised an option to acquire a 50% interest the licence and participate in drilling the Erne prospect.

Antrim drilled the Erne well 21/29d-11 in November - December 2011. The well encountered a 50 foot hydrocarbon column in the Eocene Upper Tay Sandstone, with 20 feet of net oil pay and 10 feet net gas pay. A sidetrack well, 21/29d-11Z, encountered 24 feet of net oil pay and 12 feet of net gas pay. The 21/29d-11Z well was suspended for possible use in the Fyne development plan. As part of the post-drilling analysis of the Erne wells, a separate prospect was identified to the southwest, named Corrib.

P1784 Block 21/7b – Cyclone and Typhoon

Antrim acquired 30% interest in UKCS licence P1784 Block 21/7b in January 2011 in the 26th Round, with Premier (operator and 70% interest). The block contained the Cyclone and Typhoon Tertiary Cromarty prospects. The required work programme for the licence was a firm commitment to drill an exploration well.

Well 21/7b-11 was drilled on the Cyclone prospect in November - December 2012. The well encountered 105 feet of very porous and permeable Tertiary Cromarty sands. Well logs, however, identified only residual oil, suggesting that the trap was breached and the well was plugged and abandoned. Work will continue on the licence to evaluate the remaining prospectivity in light of the Cyclone well result, including further evaluation of the Typhoon prospect.

P1563 Blocks 21/28b and 21/29c – Carra, Ree, Gill, Lene, Riddon and Scavaig

Antrim acquired 100% interest in UKCS licence P1563 Blocks 21/28b and 21/29c in February 2009 in the 25th Round. The blocks contained the small Riddon and Scavaig Eocene Tay discoveries, the Carra, Ree and Lene Eocene Tay prospects, and the Lene Paleocene prospect. The required work programme for the licence included seismic purchase and reprocessing, LMR inversion, and the contingent drilling of a well.

Antrim completed the seismic component of the workscope and identified Carra as the most promising prospect. Following the drilling of the East Fyne well and the Erne well and sidetrack, however, it was determined that there was insufficient potential to proceed with drilling. Following agreement from DECC to waive the contingent well requirement, the licence was relinquished in February, 2013.

P1625 Blocks 21/24b – West Teal, Owel, Sillan, Mask

Antrim acquired 100% interest in UKCS licence P1625 Block 21/24b in June 2009 in the 25th Round. The block contained the West Teal Jurassic Fulmar discovery, the Owel and Mask Eocene Tay prospects, and the Sillan Jurassic Fulmar prospect. The required work programme for the licence included seismic purchase and reprocessing, and the contingent drilling of a Fulmar well.

Antrim completed the seismic component of the workscope and identified West Teal as the most promising Fulmar prospect. The well must be drilled by the end of the initial licence term, which is June 2013. Antrim has been unable to identify a commercially viable export route for West Teal. Consequently, Antrim will request DECC to waive the contingent well requirement, and, on DECC consent, the licence will be relinquished.

Argentina

On March 26, 2012, Antrim and Crown Point Ventures Ltd (currently known as Crown Point Energy Inc.) ("**Crown Point**"), an Argentine-focused oil and gas company listed on the TSX Venture Exchange, entered into an arrangement agreement (the "**Arrangement Agreement**") whereby Crown Point would acquire all of the issued and outstanding common shares ("**Antrim Argentina Shares**") of Antrim's Argentina subsidiary, Antrim Argentina S.A ("**Antrim Argentina**"), which holds all of Antrim's Argentine oil and gas assets, by way of plan of arrangement under the *Business Corporations Act* (Alberta) (the "**Arrangement**"). Antrim's Argentine assets included the Rio Cullen, La Angostura and Las Violetas concessions in the Astral Basin in Tierra del Fuego and the Cerro de Los Leones concession in the Neuquén Basin in Mendoza province.

The Arrangement was completed on May 28, 2012 and Crown Point acquired all of the issued and outstanding Antrim Argentina Shares for a total consideration of approximately $37.79 million comprised of $10.0 million in cash (the "**Cash Consideration**") and the issuance of 35,761,307 common shares of Crown Point ("**Crown Point Shares**") at a deemed price of Cdn$0.80 per Crown Point Share. Pursuant to the terms of the Arrangement, the Crown Point Shares were distributed by Antrim to the holders of Common Shares on June 7, 2012 on a pro rata basis as a return of capital.

Ireland

Licensing Option 11/5 Blocks 44/4, 44/5 (part), 44/9, 44/10, 44/14, 44/15

In October 2011, Antrim was awarded a Frontier Licence Option (the "**Option**") by the Department of Communications, Energy and Natural Resources of Ireland, under the Irish 2011 Atlantic Licensing Round.

Antrim holds a Frontier Licence Option (the "Skellig Block") in the Porcupine Basin approximately 110 km off the southwest coast of Ireland. Antrim has licenced, reprocessed and interpreted 2D seismic data and has identified the

"Dunree Prospect". Antrim is currently planning a 3D seismic programme and is seeking partners to joint venture on the block and has received strong interest from industry.

Tanzania

Production Sharing Agreement - Pemba and Zanzibar

In December 2010, two agreements were signed in Tanzania which are expected to lead to the resumption of exploration activities on the production sharing agreement for the Pemba-Zanzibar exploration licence offshore and onshore Tanzania (the "**P-Z PSA**"). Antrim holds an option to acquire a 20% interest in the P-Z PSA following the pre-drilling (seismic) phase and an additional 10% interest to be exercised up to 180 days following receipt of the initial drilling results. Carried costs associated with the interests would be repaid from future production. RAK Gas, the operator, has submitted a proposal for a revised work programme to the federal government of Tanzania, with seismic operations expected to proceed in the near future.

On October 29, 2012, an agreement between the federal government of Tanzania and the government of Zanzibar on the sharing of any future hydrocarbon revenues was announced, potentially ending a moratorium which has long-delayed exploration projects. The agreement has still to be ratified by cabinet and final details are still to be agreed. It is not yet known what, if any, impact this agreement will have on the P-Z PSA.

BUSINESS OF ANTRIM

Overview

Antrim is a Calgary, Alberta, Canada based energy company engaged in the acquisition, exploration, development and production of oil and natural gas in various international locations. Antrim's portfolio of assets includes exploration and development opportunities in the United Kingdom, Ireland and Tanzania. During the past year, Antrim's emphasis has been on development of the UK North Sea assets (Causeway and Fyne) to first production.

Antrim's present strategy is to grow through a combination of exploration, development and acquisition of oil and gas properties. Antrim also considers and reviews certain strategic opportunities as they arise from time to time. Antrim's approach to investment in international exploration is predicated on recommendations from its technical and commercial team. Most opportunities pursued are internally generated within Antrim. The Company's current philosophy is to fund Antrim's ongoing activities and project sourcing from internally generated cash flow and working capital to the extent possible. As exploration opportunities are recognized, Antrim will primarily access equity markets to fund seismic and drilling activities and a combination of equity and debt for development opportunities, provided such financing can be arranged on commercially acceptable terms. Development and acquisition opportunities could be financed from combinations of then-existing working capital, new equity issues and debt instruments, if available.

As mentioned elsewhere in this AIF, Antrim divested of its Argentina business to Crown Point pursuant to the Arrangement. Antrim's shareholders retained an interest in the Argentine assets as a result of the distribution of Crown Point shares to Antrim's shareholders.

Marketing Agreement

All oil production from the Causeway Field is sold under an oil sales contract which expires on December 31, 2013. The sales price is calculated as the average monthly price for Brent Ninian Blend crude oil, in the month subsequent to the month of production. Title transfer for the sale occurs at the intake flange for the tanker vessel provided by the purchaser at the Sullom Voe Terminal. Under the terms of the contract, the purchaser has some flexibility in the timing of the loadings of crude oil, which could result in no sales of crude oil in a particular month. In such circumstances, Antrim will receive payment for the oil produced and would incur a deferred production revenue liability until the oil if sold.

Prepayment and Commodity Swaps

In January 2013, Antrim entered into a $30 million payment swap with a major financial institution (the "**Payment Swap**"). Under the terms of the Payment Swap, $30 million is repayable in 29 installments commencing September 2013 and concluding January 2016. The interest rate under the Payment Swap is fixed at 5.1%. To enable Antrim to pay amounts under the Payment Swap, Antrim entered into a Brent Oil Price Commodity Swap. The forward sale of 657,350 barrels of Brent crude oil was at a fixed price of $89.37 covering the period from February 2013 to December 2015. See “Risk Factors – Hedging”.

UK Income Tax Rate Increase

On March 23, 2011 the UK government announced an increase to the supplementary tax on UK oil and gas production from 20% to 32% effective March 24, 2011, thereby increasing the combined rate of tax on UK oil and gas production from 50% to 62%. The impact on Antrim is anticipated to be minimal over the next few years as Antrim has approximately $280 million in UK tax loss carry forwards which can be applied to reduce future taxable income.

On March 12, 2012, the UK government announced an increase in the Small Field Allowance to £150 million from £75 million and increased the size of the field qualifying for the maximum allowance to 6.25 million tonnes (roughly equivalent to 45 million boe), reducing to no allowance at 7 million tonnes (roughly equivalent to 50 million boe). Previous thresholds were a maximum allowance of 2.75 million tonnes, tapering to no allowance at 3.5 million tonnes. This change does not impact the Causeway Field, as the FDP had been approved prior to March 12, 2012, but will impact all other of Antrim’s current UK North Sea assets.

Human Resources

As at December 31, 2012, the Company had 12 full-time employees based in Calgary, Alberta, and 2 full-time employees based in Guildford, Surrey, United Kingdom. The Company also utilized the services of several professionals on a part-time contract or consulting basis. Antrim seeks to employ individuals and utilize the services of consultants who have international oil and gas experience.

Competition

The oil and gas industry is highly competitive particularly as it pertains to the search for and development of new sources of crude oil and natural gas reserves, the construction and operation of crude oil and natural gas pipelines and facilities, and the transportation and marketing of crude oil, natural gas, sulphur and other petroleum products. Antrim’s competitors include major integrated oil and gas companies and numerous other independent oil and gas companies, some of which have greater financial and other resources than Antrim. See "Risk Factors – Competition".

Environmental Protection

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions, federal, regional, national, state and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions and discharges of various substances and materials (including wastes) produced in association with or otherwise arising from oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, decommissioned, abandoned and reclaimed in accordance with relevant laws and permits and including, where relevant, to the satisfaction of applicable regulatory authorities. Existing and possible future environmental legislation, regulations and actions could cause additional expense, capital expenditure, restrictions and delays in the activities of the Corporation, the extent of which cannot be predicted. See "Risk Factors – Government and Environmental Regulations" and "Risk Factors – Climate Change Impact".

The Company is committed to meeting its responsibilities to protect the environment wherever it operates and procedures are in place to ensure utmost care is taken in the day-to-day management of its properties. The Company believes in well abandonment and site restoration in a timely manner to ensure minimal damage and overall costs to the Company. The Company makes full provision for the future cost of decommissioning oil production facilities and pipelines in the United Kingdom on a discounted basis on the installation of those facilities. At December 31, 2012, the estimated undiscounted abandonment and restoration costs of the Company are approximately $11.2 million.

RISK FACTORS

Financing Requirements and Liquidity

It may take many years and substantial cash expenditures to pursue exploration activities on Antrim's existing undeveloped properties. Accordingly, Antrim is likely to need to raise additional funds from outside sources in order to explore and develop its properties in a timely manner.

The Company'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 the Company has or intends to have operations, and competition for funds from possible alternative investment projects. Although there have been improvements in the global economy and financial markets in recent months, there continues to be restrictions on the availability of credit which may limit Antrim's ability to access debt or equity financing for its development projects.

The Company may find it necessary in the future to obtain additional debt or additional equity to support ongoing operations, to undertake capital expenditures or to undertake acquisitions or other business combination transactions. There can be no assurance that additional financing will be available to the Company when needed or on terms acceptable to Antrim. The Company's inability to raise financing to support ongoing operations or to fund capital expenditures or acquisitions could limit the Company's growth and may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

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

The Company continuously monitors its cash position, capital commitments and future capital requirements in order to ensure sufficient liquidity and capital resources are available. If adequate funds are not available, the Company will be required to scale back or even relinquish certain projects. If additional financing is raised by the issuance of shares from treasury, control of Antrim may change and shareholders may suffer dilution.

Oil and Gas Activities Involve Risks, Many of Which Are beyond Antrim's Control

The business of exploration and production of oil and gas involves a high degree of risk which a combination of experience, knowledge and careful evaluation, may not be enough to eliminate any amount of the risk. Few properties that are explored are ultimately developed into producing oil and gas fields.

The Company's rights to exploit its oil and gas assets are limited in time. There is no guarantee or assurance that such rights can be extended or that new rights can be obtained to replace any rights that expire.

Significant expenditure is required to establish the extent of oil and gas reserves through seismic surveys and drilling and there can be no certainty that oil and gas reserves will be found.

It is difficult to project the costs of implementing drilling programs due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over-pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior wells or additional seismic data and interpretations thereof.

Drilling may involve unprofitable efforts, not only with respect to dry wells, but also with respect to wells which, though yielding some petroleum, are not sufficiently productive to justify commercial development or cover operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, 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. While close well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Company's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Company's control, including the availability of drilling and related equipment; the availability and proximity of pipeline capacity; the availability of processing capacity; the availability and productivity of skilled labor; the effects of inclement weather; unexpected cost increases; currency fluctuations; the supply of and demand for oil and natural gas; the availability of alternative fuel sources; accidental events; and regulation of the oil and natural gas industry by various levels of government and governmental agencies. Because of these factors, the Company could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it hopes to produce.

Reliance on Third Parties

To the extent Antrim is not the operator of its oil and natural gas properties (in particular, Antrim's Causeway property), Antrim 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 Valiant and TAQA.

Licensing and Title Risks

Antrim's properties are generally held in the form of licences, concessions, permits and regulatory consents ("**Authorizations**"). Antrim's activities are dependent upon the grant and maintenance of appropriate Authorizations, which may not be granted; may be made subject to limitations which, if not met, will result in the termination or withdrawal of the Authorization; or may be otherwise withdrawn. Also, in the majority of its Authorizations, the Company is a joint interest-holder with another third party over which it has no control. An Authorization may be revoked by the relevant regulatory authority if the other interest-holder is no longer deemed to be financially credible. There can be no assurance that any of the obligations required maintaining each Authorization will be met. Although the Company believes that the Authorizations will be renewed following expiry or granted (as the case may be), there can be no assurance that such Authorizations will be renewed or granted or as to the terms of such renewals or grants. The termination or expiration of the Company's Authorizations may have a material adverse effect on the Company's results of operations and business.

In addition, the areas covered by the Authorizations are or may be subject to agreements with the proprietors of the land. If such agreements are terminated, found void or otherwise challenged, the Company may suffer significant damage through the loss of opportunity to identify and extract oil or gas.

Title to oil and natural gas interests is often not determinable without incurring substantial expense. In accordance with industry practice, Antrim will conduct such title reviews in connection with its principal properties as it believes are commensurate with the value of such properties. The actual interest of Antrim in certain properties may vary from its records.

Loss from Operations

The Company has an accumulated deficit at December 31, 2012 of $320.2 million. No assurance can be given that the Company 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 the Company's control, and are generally sold at contract or posted prices. Changes in world crude oil and natural gas prices may significantly affect Antrim's results of operations and cash generated from operating activities. Consequently, such prices may also affect the value of the Company's oil and gas properties and the level of spending for oil and natural gas exploration and development.

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

Any material declines in prices could result in a reduction of the Company's net production revenue. The economies of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of the Company's reserves and the Company limiting or abandoning an exploration program on its undeveloped properties. The Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's net production revenue. All of the Company'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

The nature of Antrim's operations results in exposure to fluctuations in commodity prices. Antrim monitors its exposure to such fluctuations and where appropriate utilizes derivative financial instruments to mitigate the potential impact of declines in crude oil prices.

Under IFRS, derivative instruments that do not qualify as hedges for accounting purposes or are not designated as hedges, are fair valued with the resulting changes recognized in the current period net earnings. The use of derivative financial instruments may introduce significant volatility into Antrim's reported net earnings.

The terms of Antrim's hedging agreements may limit the benefit of commodity price increases. Antrim may also incur financial loss because of hedging arrangements if Antrim is unable to produce crude oil to fulfill delivery obligations or if counterparties fail to fulfill their obligations under the hedging agreements.

In January 2013, Antrim entered into a payment swap with a major financial institution for $30 million which is repayable in 29 installments from September 2013 to January 2016. The interest rate under the Payment Swap is fixed at 5.1%. To enable ARNIL to make these payments, ARNIL entered into a forward sale of 657,350 barrels of Brent crude oil at a fixed price of $89.37 covering the period from February 2013 to December 2015. While the forward oil swap may be suitable for hedge accounting under IFRS, the Company has elected not to demonstrate that this is an effective hedge, and thus changes in the fair value of the derivative will be recognized in the income statement in the period in which they arise. The Company's anticipated revenue for 2013, as well as the Company's ability to repay the payment swap, is dependent upon the future production rates from the Causeway and Cormorant East fields as well as oil prices.

Reserves and Resource Risks

The reserve and resource data included herein are expressions of judgment based on knowledge, experience and industry practice. In general, estimates of economically recoverable oil and natural gas reserves and the future net revenue there from are based upon a number of variable factors and assumptions, such as expected reservoir characteristics based on geological, geophysical and engineering assessments; ultimate reserve recovery; timing and amount of capital expenditures; future production rates based on historical performance and expected future operating and investment activities; future oil and natural gas prices and quality differentials; marketability of oil and gas; royalty rates; assumed effects of regulation by governmental agencies; and future development and operating costs, all of which may vary materially from actual results. It should not be assumed that estimated future net revenue is representative of the fair market value of the Company's properties. In addition, estimated reserves may change from time to time based on new or reprocessed information or new interpretations of existing or new information.

The resources estimates provided herein are estimates only. The estimate of resources includes contingent resources that have not been adjusted for risk based on the chance of development. It is not an estimate of volumes that may be discovered. Actual recovery may be less. The estimate of resources also includes prospective resources that have been risked for chance of discovery, but have not been risked for chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development.

The FDP submitted by operator Valiant and approved by DECC for the Fionn Field cites reserves that are less than those estimated in the reserves report for Antrim dated March 26, 2013, prepared by McDaniel & Associates Consultants Ltd. ("**McDaniel**") and effective as of December 31, 2012 ("**The McDaniel report**").

Need to Replace Reserves

Antrim's future crude oil and natural gas reserves and production, and therefore its operating cash flows and results of operations, are highly dependent upon the Company's success in exploiting the current reserve base and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, Antrim's reserves and production will decline over time as reserves are produced. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, the ability to make the necessary capital investments to maintain and expand the Company's oil and natural gas reserves will be impaired.

Offshore Exploration

The Company 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.

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 the Company and may delay exploration and development activities. Antrim may be subject to relatively limited availability of offshore drilling rigs to proceed with a planned 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.

Reliance on Key Personnel

The success of Antrim will be largely dependent upon the performance of its management and key employees. Failure by Antrim to retain or to attract and retain additional key employees with necessary skills could have a materially adverse impact upon Antrim's growth and profitability. Antrim has limited key person insurance for its management and none for other key employees. These individuals, and the contributions they will make, are important to the future operations and success of Antrim.

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 Antrim's interests and may conflict with Antrim'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 Antrim's, even if they generally share Antrim's objectives. Demands by or expectations of governments, co-venturers, customers, and others may affect Antrim's strategy regarding the various projects. Failure to meet such demands or expectations could adversely affect Antrim's participation in such projects or its ability to obtain or maintain necessary licences and other approvals.

Foreign Currency Rate Risk

A significant portion of the Company's activities is transacted in or referenced to United States dollars, Canadian dollars, or British pounds sterling. The Company's operating costs and certain of the Company's payments required 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 US dollar, and each of those currencies against any other local currencies in jurisdictions where properties of the Company are located, could result in unanticipated fluctuations in the Company's financial results which are denominated in US dollars. The Company has not entered into any risk management contracts to hedge its exposure to foreign exchange rates.

Commodity Price Risk

From time to time Antrim 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, Antrim would not benefit from such increases. See also "Risk Factors – Hedging".

Marketability of Crude Oil and Natural Gas

The marketability and price of oil and natural gas produced and which may be acquired or discovered by the Company will be affected by numerous factors beyond the control of the Company. The Company will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil which are and may be produced by the Company. The ability of the Company to market its natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. The Company is also subject to market fluctuations in the prices of oil and natural gas, deliverability uncertainties related to the proximity of its reserves to pipeline and processing facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business. See also "Business of Antrim –Marketing Agreement".

Cyclical and Seasonal Impact of Industry

Antrim's operational results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by global supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. A decline in oil and natural gas prices could have an adverse effect on the Company's financial condition.

Competition

The oil and gas industry is highly competitive particularly as it pertains to the search for and development of new sources of crude oil and natural gas reserves, the construction and operation of crude oil and natural gas pipelines and facilities, and the transportation and marketing of crude oil, natural gas, sulphur and other petroleum products. Antrim's competitors include major integrated oil and gas companies and numerous other independent oil and gas companies, some of which have greater financial and other resources than Antrim. The oil and natural gas industry is intensely competitive and the Company must compete in all aspects of its operations with a substantial number of other companies which have greater technical or financial resources. All of Antrim's UK revenue is currently derived from oil sales to one marketer. There is no assurance that Antrim will be able to successfully compete against its competitors. However, Antrim strives to be competitive by maintaining a strong financial position and by using its network of international contacts and relationships to source and secure appropriate investment opportunities.

Government and Environmental Regulations

The petroleum industry is subject to regulation, enforcement and intervention by governments in such matters as the awarding and licensing of exploration and production interests, the imposition of specific drilling obligations, environmental protection and pollution controls, health and safety aspects of on and off-shore activity and operations, control over the development, decommissioning 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 regulation may be changed from time to time in response to economic or political conditions. The implementation of new legislation or regulations or the modification of existing legislation or 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 the Company. 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 current tax regime in the UK is favorable to companies of the Company'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 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. A small field relief of up to 10% of the 20% supplemental rate is granted in respect of fields of less than 25 mmbbls and so is potential benefit to the Company. 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 23, 2011, the UK government announced an increase to the supplementary tax on UK oil and gas production from 50% to 62%. Any changes to these laws would impact the net present worth of the Company's reserves. On March 21, 2012, the UK government announced that the maximum amount of the small field allowance introduced in Finance Act 2009 will be doubled from £75 million to £150 million. The qualifying criteria will also be relaxed. The maximum allowance will be available for fields which have reserves in place of 6.25 million tonnes (approximately 45 million barrels) or less, reducing to no allowance at 7 million tonnes (approximately 50 million barrels). The previous thresholds were 2.75 million and 3.5 million tonnes. For these purposes, a new field will be one with development authorization on or after March 21, 2012. The results of this change in the maximum allowance are expected to provide Antrim with additional tax benefits for the development of certain qualifying UK fields.

When originally introduced the maximum tax value of small field allowance was £15 million, being £75 million multiplied by the supplementary charge tax rate of 20%. By contrast the new allowance will be worth a maximum of £48 million (£150 million at 32%) per relevant field.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions, federal, regional, national, state and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions and discharges of various substances and materials (including wastes) produced in association with or otherwise arising from oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, decommissioned, abandoned and reclaimed in accordance with relevant laws and permits and including, where relevant, to the satisfaction of applicable regulatory authorities. Existing and possible future environmental legislation, regulations and actions could cause additional expense, capital expenditure, restrictions and delays in the activities of the Company, the extent of which cannot be predicted. Before exploration and/or production activities can commence, the Company must obtain regulatory approval and relevant licences and there is no assurance that such approvals or licences will be obtained.

Environmental legislation and enforcement policy is evolving in a manner expected to result in more onerous and stricter requirements, standards and enforcement, larger fines and greater liability and potentially increased capital expenditures and operating costs. While the directors believe that the Company's current provision for compliance with environmental laws, regulations and liabilities (including decommissioning) in the countries in which it operates is reasonable, no assurance can be given that new rules and regulations will not be enacted or existing legislation, rules and regulations will not be applied in a manner which could limit or curtail the Company's production or development or result in increased liabilities. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of acquisition, exploration, development or production activities or otherwise adversely affect the Company's financial condition, results of operations or prospects.

The Company is committed to meeting its responsibilities to protect the environment wherever it operates and procedures are in place to ensure utmost care is taken in the day-to-day management of its properties. The Company believes in well abandonment and site restoration in a timely manner to ensure minimal damage and overall costs to the Company.

Stage of Development

The Company may be subject to growth-related risks, capacity constraints and pressure on its internal systems and controls, particularly given the early stage of the Company's development. The ability of Antrim to manage growth effectively will require it to continue to expand its operational and financial systems and to train and manage its employee base. The inability of Antrim to deal with this growth could have a material adverse impact on its business, operations and prospects.

Strategic Partnerships

As part of its development plan in the North Sea, the Company may consider the formation of strategic partnerships, including the one formed in 2010 with Valiant as it relates to the sharing of development costs and other similar interests in the

Causeway area including, 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, the Company must produce oil and gas in sufficient quantities and then sell such oil and gas at sufficient prices to produce a profit. The Company 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. The Company 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

The Company'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 the Company and others. In accordance with customary industry practice, the Company 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 the Company.

Although the Company 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 the Company'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 the Company. 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 the Company. Moreover, there can be no assurance that the Company will be able to maintain adequate insurance in the future at rates that it considers reasonable.

Foreign Operations

Presently, all of Antrim's oil and gas operations and assets are located in foreign jurisdictions. As a result, the Company 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 the Company'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 the Company's oil and natural gas exploration and production activities. The Company'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, the Company 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, Antrim'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, the Company's foreign exploration, development and production activities could be substantially affected by factors beyond the Company's control, any of which could have a material adverse effect on the Company.

Regulatory Approvals

The further development of the Company's properties requires the approval of applicable regulatory authorities to the plans of the Company 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 the Company.

Climate Change Impact

Antrim faces a variety of uncertainties related to climate change. The oil and gas industry is subject to extensive environmental regulation pursuant to legislation in the United Kingdom. These range from potential impacts from emissions restrictions, carbon taxes and other government policy initiatives, to changes in weather patterns that may affect operations. Although Antrim is not a large emitter of greenhouse gases, these forms of legislation may have an impact on both revenues and cost structures at a future undetermined time.

Acquisition Risks

Although the Company performs a review of properties prior to acquiring them that it believes is consistent with industry practice, such reviews are inherently incomplete. It is generally not feasible to review in depth every practice and every individual property involved in each acquisition. Generally, the Company will focus its due diligence efforts on higher valued properties and will sample the remainder. However, even an in-depth review of all properties and records may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. The Company may be required to assume pre-closing liabilities, including environmental liabilities, and may acquire interest in properties on an “as is” basis.

Legal Proceedings

Antrim may be involved in litigation from time to time in the ordinary course of its business. Although Antrim is not currently a party to any legal proceedings, except as described in Note 21 of the Company's annual financial statements for the year ended December 31, 2012, legal proceedings could be filed against Antrim in the future. No assurances can be given as to the final outcome of any legal proceedings or that the ultimate resolution of any legal proceedings will not have a material adverse effect on Antrim.

Force Majeure

The Company’s projects may be adversely affected by risks outside the control of the Company including labor unrest, civil disorder, war, subversive activities or sabotage, fires, floods, explosions or other catastrophes, epidemics or quarantine restrictions.

Common Share Price Volatility

The market price of Antrim’s common stock could be subject to wide fluctuations in response to Antrim’s results of operations, changes in earnings estimates by analysts, changing conditions in the oil and gas industry or changes in general market, economic or political conditions.

Absence of Cash Dividends.

Antrim has not paid any cash dividends to date on the common stock and there are no plans for such dividend payments in the foreseeable future.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The Company's Statement of Reserves Data and Other Oil and Gas Information dated March 26, 2013 and effective December 31, 2012 is attached as Schedule "A" hereto and is incorporated by reference in this Annual Information Form ("**AIF**").

Reserves Update

In February 2013 Antrim elected out of participating further in the Fionn Field development and on March 26, 2013 the Company discontinued development of the Fyne and Crinan Fields following a significant escalation of expected future development costs. The impact on Antrim's reserves is as follows:

UK Proved plus Probable Reserves	**Net (Mbbls)**
At December 31, 2012	16,626
Less:	
Fionn Field	(1,727)
Fyne and Crinan Fields	(11,758)
Revised proved plus probable reserves	**3,141**

The updated present value cash flow after tax using a 10% discount rate is $144,775,000.

PRINCIPAL OIL AND NATURAL GAS PROPERTIES

Properties

The following is a description of Antrim's principal oil and natural gas properties held as at December 31, 2012. The term "working interest", when used to describe Antrim's share of reserves, acreage or production, means the total of Antrim's net working interest share after deducting interests owned by others. Reserve amounts with respect to Antrim's interests in the Causeway and Fyne, Crinan and Dandy Licence areas in the United Kingdom are stated as at December 31, 2012, net to Antrim based on forecast prices and costs as evaluated by McDaniel in the McDaniel Report dated March 26, 2013. See "Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data". Information in respect of gross and net acres, well counts and production are as at December 31, 2012 except where indicated otherwise. The company's statement of Reserve Data and Other Oil and Gas Information is effective December 31, 2012 and does not reflect the relinquishments subsequent to that date.

Summary of Properties Table

Property [1]	**Operator**	**Working Interest %**	**Status and Licence Expiry Date**[1]	**Gross Licence Area (km^2)**
UKCS Block 211/22a SE – Causeway, Fionn[2], West Causeway	Valiant Causeway Limited	35.50	Exploration and development	49.8
UKCS Block 211/23d – Causeway	Valiant Causeway Limited	35.50	Production	63.6
UKCS Block 21/28a – Fyne, Dandy[3] and Crinan	Antrim Resources (N.I.) Limited	100.00	Exploration and development	70.2
UKCS Block 21/7b	Premier Oil UK Limited	30.00	Exploration and development	175.0
UKCS Block 211/22a Kerloch Area - Kerloch	Dana Petroleum plc	13.65	Exploration	50.8
UKCS Block 211/22a Contender Area – Cormorant East	TAQA Bratani Limited	8.40	Production	35.1
UKCS Block 21/24b	Antrim Resources (N.I.) Limited	100.00	Exploration	145.7
UK – Block 21/28b and Block 21/29c [4]	Antrim Resources (N.I.) Limited	100.00	Exploration	199.0

UKCS Block 21/29d	Antrim Resources (N.I.) Limited	50.00	Exploration	109.7
Ireland Block 44/1, 44/5 (partial), 44/9, 44/10, 44/14 and 44/15(5)	Antrim Exploration (Ireland) Limited	100.00	Exploration	1,409.0
Tanzania Production Sharing Agreement - Pemba Zanzibar(6)	RAK Gas LLC	nil (Options to acquire 30.00)	Exploration	14,100.0

Note:

(1) See property description for licence expiry terms.
(2) Fionn sub-area (approximately 28.0 km^2) relinquished in January 2013.
(3) Dandy Prospective Area (approximately 34.8 km^2) relinquished in March 2013.
(4) Licence P1563 Blocks 21/28b and 21/29c relinquished in February 2013.
(5) See property description; this is a Licensing Option which can qualify for a full Frontier Exploration Licence within two years.
(6) See property description; Antrim has an option to acquire up to 30% interest in the Production Sharing Agreement.

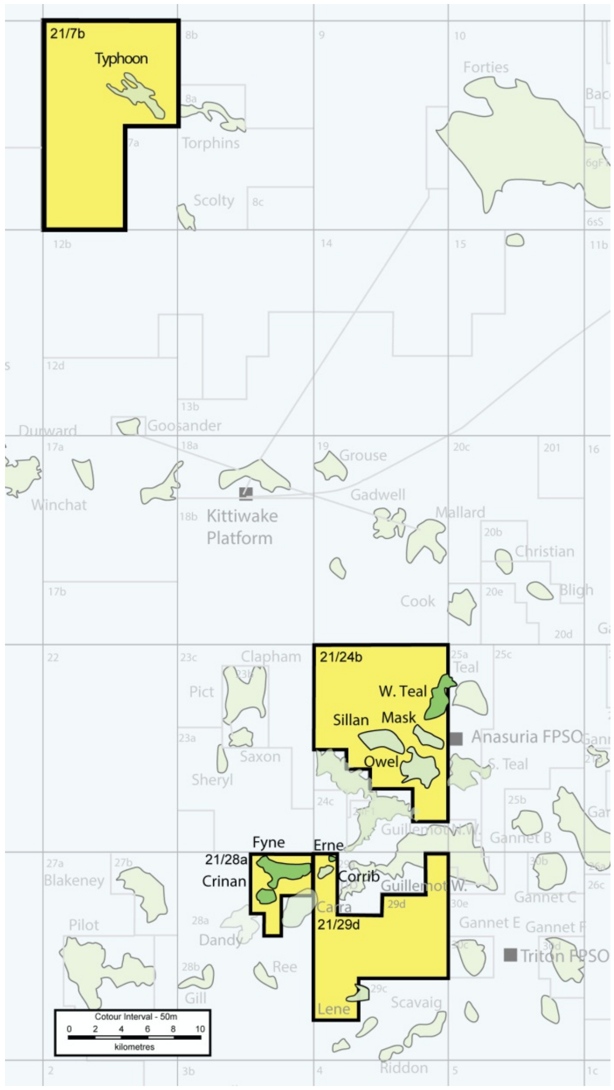
United Kingdom

Antrim has been active in the United Kingdom since 2004 with activities concentrated in the North Sea and offshore Ireland.

In the Central North Sea, Antrim holds a 100.0% interest in the Fyne Licence P077 Block 21/28a, a 50% interest in Licence P1875 Block 21/29d, a 100% interest in Licence P1625 Block 21/24b, and a 30% interest in Licence P1784 Block 21/7b. In the Northern North Sea, Antrim holds a 35.5% interest in the UKCS Licences P1383 Block 211/23d and P201 Block 211/22a South East Area, 13.65% interest in the adjacent P201 Block 21/22a Kerloch Area Licence, and 8.4% interest in the P201 Block 21/22a Contender Area Licence.

Following is a description and current status of these assets.

UK Central North Sea – Greater Fyne Area



* the map reflects the relinquishment of licence P1563 Blocks 21/28b and 21/29c and partial relinquishment in P077 Block 21/28a of the Dandy Prospective Area in Q1 2013

<u>P077 Block 21/28a – Fyne, Dandy and Crinan</u>

Antrim holds 100% interest in UKCS Licence P077 Block 21/28a. The licence contains the Fyne Field, the Dandy Field and the Crinan Field (previously referred to as "Area 4"), all Eocene Tay pools. Antrim entered the licence in 2006 as a 75% interest owner and operator, with First Oil holding the remaining 25% interest.

In 2007 and 2008, 3D seismic was acquired, and five penetrations were drilled in the Fyne Field. In 2010, Antrim entered into an EIA with Premier to jointly investigate development options for the Fyne area. Premier exercised an option to acquire 39.9% interest in the licence from Antrim and was appointed operator. An appraisal well was drilled to delineate the eastern area of the Fyne Field, but was at the lower end of pre-drill estimates, and the well was plugged and abandoned. Premier and First Oil subsequently withdrew from the licence, leaving Antrim with 100% interest.

On March 26, 2013 the Company discontinued development of the Fyne Field. Until very recently, estimated costs indicated that the planned Fyne development passed the Company's economic threshold and contingent on timing of the redeployment of the FPSO from its current location was on track for a late 2014 start-up. However, projected capital costs have increased substantially, and in the Company's view now make the project uneconomic.

P1875 Block 21/29d – Erne and Corrib

Antrim holds a 50% interest in UKCS licence P1875 Block 21/29d. Antrim acquired 100% interest in the licence in January 2011 in the 26th UK Seaward Licensing Round. Premier subsequently exercised an option under an EIA to acquire 50% interest, leaving Antrim with the remaining 50% interest. The block contains the Erne Eocene Tay discovery and the Corrib Eocene Tay prospect.

Antrim drilled the Erne well 21/29d-11 and sidetrack well, 21/29d-11Z in 2011, discovering a small Eocene Tay pool. The 21/29d-11Z well was suspended for possible use in the Fyne development plan. As part of the post-drilling analysis of the Erne wells, a separate prospect was identified to the southwest, named “Corrib”.

The initial term of the licence will expire in January 2015. All commitments for the initial term have been fulfilled. In January 2015, Antrim can renew the licence for a second term.

P1563 Blocks 21/28b and 21/29c – Carra, Ree, Gill, Lene, Riddon and Scavaig

Antrim relinquished its 100% interest in Licence P1563 Blocks 21/28b and 21/29c in February 2013. The licence, which was acquired in February 2009 in the 25th UK Seaward Licensing Round, contained the small Riddon and Scavaig Eocene Tay discoveries, the Carra, Ree and Lene Eocene Tay prospects, and the Lene Paleocene prospect

Antrim acquired and re-processed seismic data on the blocks. After drilling the Erne well and sidetrack well in 2011 and the East Fyne well in 2012, it was determined that there was insufficient potential to proceed with drilling an exploration well on Licence P1563 by February 2013, as required by the licence terms. Following agreement from DECC to waive the contingent well requirement, the licence was relinquished in February 2013.

P1625 Blocks 21/24b – West Teal, Owel, Sillan, Mask

Antrim holds 100% interest in UKCS licence P1625 Block 21/24b. The licence, which was acquired in June 2009 in the 25th UK Seaward Licensing Round, contains the West Teal Jurassic Fulmar discovery, the Owel and Mask Eocene Tay prospects, and the Sillan Jurassic Fulmar prospect.

Antrim acquired and re-processed seismic data on the blocks. The licence terms require that a contingent Fulmar well be drilled by June, 2013. Antrim has been unable to identify a commercially viable export route for West Teal. Consequently, DECC will be requested to waive the contingent well requirement and, with DECC consent, the licence will be relinquished.

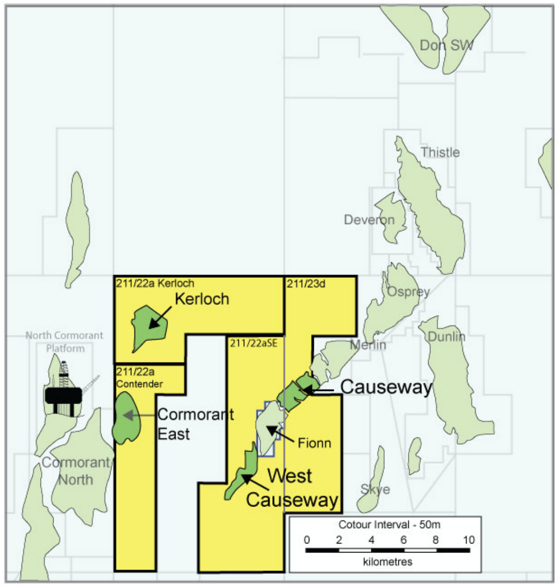
P1784 Block 21/7b – Cyclone and Typhoon

Antrim holds a 30% interest in UKCS licence P1784 Block 21/7b. The licence, which was acquired in January 2011 in the 26th UK Seaward Licensing Round with Premier (operator and 70% interest), contained the Cyclone and Typhoon Tertiary Cromarty prospects.

Well 21/7b-11 was drilled on the Cyclone prospect in November 2012. Although the well encountered a large section of very porous and permeable Tertiary Cromarty sands, only residual oil saturation was present and the well was plugged and abandoned. Work will continue up to at least the expiry of the initial term in January 2015 to evaluate the remaining prospectivity on the licence.

Antrim was required to drill a well on the Typhoon prospect of the licence by 2015. Antrim and operator Premier drilled a well on Cyclone prospect of the licence in 2012, and has asked DECC to accept this as fulfillment of their drilling obligation. Contingent on DECC acceptance, there are no remaining obligations for the initial term of the licence.

UK Northern North Sea Block 211/22a South East Area and UK North Sea Block 211/23d – Causeway



* the map reflects the partial relinquishment in P201 Block 211/22a SE of the Fionn Subarea in March 2013

P1383 Block 211/23d and P201 Block 211/22a South East Area – Causeway, Fionn and West Causeway

Antrim holds a 35.5% interest in UKCS Licence P201 Block 211/22a South East Area and UKCS Licence P1383 Block 211/23d. A 79% interest in Block 211/22a South East was acquired in a series of transactions in 2004 and 2005, while 100% interest in the Block 211/23d interest was acquired in the 23rd UK Seaward Licensing Round in 2006. In 2006, through a series of farmout transactions and exercise of rights of another company under an area of mutual interest agreement, Antrim's interest was reduced to 65.5% in both licences. In 2011, Antrim sold a 30% interest in the licences and transferred operatorship to Valiant, reducing the Company's interest to 35.5%. The licences contain the Causeway Field (formerly referred to as "East Causeway" and "Far East Causeway), the Fionn Field (formerly referred to as "Central Causeway") and the West Causeway Field. In January 2013, Antrim opted out of the Fionn Field subarea of P201 Block 211/22a South East Area.

Antrim drilled six wells on the Causeway – Fionn – West Causeway structure between 2006 and 2008. Three wells were tested, the most prolific of which was well 211/23d-17Z which tested oil at a peak rate of 14,500 barrels of oil per day ("**bopd**") from the Brent Tarbert and Etive formations. All six wells were suspended for future use as production or water injection wells. A FDP was submitted to DECC in December 2008 with a phased programme starting with Causeway. That FDP submission was suspended while awaiting further progress on an export route.

Following the divestment of a 30% interest to Valiant, an export route was negotiated with TAQA for use of the North Cormorant production platform. Antrim and Valiant approved a phased development scheme, with the initial phase consisting of a single production well and an injection well in the Causeway Field. The Causeway FDP was approved by DECC in December 2011. Production commenced on October 30, 2012, with gross production rates of approximately 4,500 bopd from a single production well. Initial production rates were impacted by longer-than-anticipated clean-up and commissioning due to the long horizontal nature of the well. Rig operations to complete the water injector proceeded in early 2013. Startup of both the water injection and the electrical submersible pumps are scheduled for the second half of 2013.

In August 2012, DECC approved the FDP for the Fionn Field. Subsea installations for the Fionn Field were done at the same time as the Causeway Field. Antrim's share of costs for Fionn was carried by Valiant. Projected costs associated with the development of the Fionn Field increased to the extent that the project no longer met Antrim's economic criteria. In January 2013, Antrim therefore elected to opt out of the Fionn Field development. Antrim remains a 35.5% interest owner of the remainder of P201 Block 211/22a South East Area, including the West Causeway Field. The West Causeway Field contains one suspended well which is available to be completed and tied into the Causeway – Fionn export system.

Licence P1383 Block 211/23d completes its second four year term in December 2013. Any area not identified as a "Producing Part" or a "Prospective Area" will be relinquished at that time. Currently, the Company does not consider any area within the licence other than the Causeway Field to have commercial prospectivity.

P201 Block 211/22a North West Area – Now subdivided into P201 Block 211/22a Kerloch Area and Block 211/22a Contender Area

Antrim acquired a 21% WI in P201 Block 211/22a North West Area in 2005.

In November 2007, Antrim participated in drilling the non-operated Kerloch prospect in the Kerloch Licence. The well discovered an oil column of approximately 116 feet in the Ness Formation and a number of oil samples were taken. No flow test was performed; however a comprehensive set of data including cores, wireline logs, reservoir pressure measurements and fluid samples was collected. The Kerloch well was suspended to allow potential re-entry and future use.

On August 25, 2011, Antrim announced that it had reached a farm-out agreement with TAQA relating to UKCS Licence P201 Block 211/22a North West Area. In September 2011, DECC agreed to subdivide the licence into two sub-areas: the Kerloch Area in the north and the Contender Area in the south. By committing to drill an exploration well in the south, TAQA earned a 60% interest in the Contender Area. Antrim's working interest in the Contender Area was reduced to 8.4%. Once the exploration well was drilled, TAQA earned 35% interest in the Kerloch Area. Antrim's remaining working interest in the Kerloch Area was reduced to 13.65%.

TAQA assumed operatorship of the Contender Area and drilled the exploration well on the Contender Prospect from the Cormorant North platform in August – October 2012. Net oil pay in excess of 60 feet was encountered in the Tarbert member of the Jurassic Brent sandstones, with greater than expected porosity and hydrocarbon saturation, and no water bearing sands were identified. The discovery was named the "Cormorant East" Field, and an FDP was submitted to DECC. The well was completed and put on production in January 2013 at an initial rate of 5,500 bopd. Cormorant East is initially being produced under primary depletion with a single production well, with the potential to install a water injection scheme and/or additional production wells at a later date.

Ireland

Antrim holds 100% interest in Licensing Option 11/5 Blocks 44/4, 44/5 (part), 44/9, 44/10, 44/14 and 44/15, an area of 1,409 km^2 in the Porcupine Basin situated approximately 110 km off the SW coast of Ireland. The Option was awarded in October 2011, the Department of Communications, Energy and Natural Resources of Ireland, under the Irish 2011 Atlantic Licensing Round.

Antrim is conducting a seismic work program to map and prioritize leads and prospects on the blocks. The Option allows Antrim to propose a work programme for a full Frontier Exploration Licence at any time up to October 31, 2013 for up to 75% of the initial area, with an initial term of three years followed by three terms of four years (15 years in total).

Tanzania

Antrim holds an option to acquire a 20% interest in the Pemba – Zanzibar Production Sharing Agreement in offshore Tanzania following the pre-drilling (seismic) phase of the exploration programme, and an additional 10% interest to be exercised up to 180 days following receipt of the initial drilling results. Antrim initially acquired 100% interest in the PSA in 1997. A revenue sharing dispute between the federal government of Tanzania and the semi-autonomous revolutionary government of Tanzania has placed the PSA in an effective state of force majeure. Through a series of transactions, Antrim no longer holds any direct interest in the rights of the PSA, but legally holds the two options to re-acquire up to a 30% interest.

On October 29, 2012, an agreement between the federal government of Tanzania and the government of Zanzibar on the sharing of any future hydrocarbon revenues was announced, potentially ending a moratorium which has delayed exploration of the licence. The agreement has still to be ratified and final details are still to be agreed. It is not yet known what, if any, impact this agreement will have on the P-Z PSA.

Material Contractual Obligations Associated with Properties

As of December 31, 2012 Antrim has the following material contractual commitments with respect to the Company's properties:

United Kingdom:

P201 Block 211/22a South East Area – This licence is a 4th Round Licence and will expire in 2018. FDPs for the Causeway Field and the Fionn Field were approved in 2011 and 2012 respectively and include defined productive areas around the fields, protecting both from any fallow designation.

P201 Block 211/22a Contender Area – This licence is a 4th Round Licence and will expire in 2018. An FDP for the Cormorant East Field was approved in 2012 and includes a defined productive area, protecting it from any fallow designation.

P201 Block 211/22a Kerloch Area – This licence is a 4th Round Licence and will expire in 2018. Drilling of the Contender well in 2012 protects it from any fallow designation, as the Contender Area and Kerloch Area were previously one single subarea.

P1383 Block 211/23d – This licence, which, in addition to block 211/22a South East Area, comprises the "Causeway area", was awarded on a promote licence basis in 2005. As per the terms of the promote licence, a mandatory relinquishment of 46.5 km^2 of the original 96.3 km^2 of the licence was made in December 2009. The relinquished area was decreased to have the least potential on the licence, and does not include any of the delineated Causeway Field or the Fionn Field. The licence completes its second four year term in December 2013. Any area not identified as a "Producing Part" or a "Prospective Area" will be relinquished at that time. Currently, the Company does not consider any area within the licence other than the Causeway Field to have commercial prospectivity.

P077 Block 21/28a – The licence, which was due to expire on November 25, 2011 was extended by DECC for three years to November 25, 2014 on the condition that the Fyne Field FDP is submitted in its final form by March 29, 2013. First production must be achieved from any of the three identified Prospective Areas (Fyne Field, Dandy Field and Crinan Field) within the three year licence extension period in order for that Prospective Area to become a Producing Area and the licence to continue. If first production is not achieved in a Prospective Area by November 25, 2014, DECC can revoke the licence relative to that Prospective Area. DECC has indicated that if first oil is achieved in the Fyne Prospective Area by November 25, 2014, they will not revoke the licence relative to the Crinan Prospective Area before November 25, 2016.

P1563 Blocks 21/28b & 21/29c – Antrim was required to purchase and reprocess 70 km^2 of 3D seismic which was completed in 2010. An additional purchase of 55 km^2 and acquisition of 50 km^2 of 3D is required prior to year end 2013. Antrim is also committed to a contingent well on the licence by February 12, 2013. Following the drilling of two nearby wells in East Fyne and Erne, Antrim requested DECC to waive the remaining seismic and drilling commitments and relinquish the licence. The licence was relinquished in February 2013.

P1625 Block 21/24b – Antrim was required to acquire and reprocess 147 km^2 of 3D seismic prior to year end 2013. This commitment was fulfilled in 2010. Antrim is also committed to a contingent well on the licence by June 20, 2013. Due to the lack of a commercially viable export route, DECC will be requested to waive the drilling commitment and, with DECC consent, the licence will be relinquished.

P1875 Block 21/29d – Antrim is required to acquire and reprocess 65 km^2 of 3D seismic prior to 2013. Antrim is also committed to drill a well on the licence by 2015. The Erne well 21/29d-11 drilled in 2011 satisfied this obligation.

P1784 Block 21/7b – Antrim was required to drill a well on the Typhoon prospect of the licence by 2015. Antrim and operator Premier drilled a well on Cyclone prospect of the licence in 2012, and has asked DECC to accept this as fulfillment of their drilling obligation. Contingent on DECC acceptance, there are no remaining obligations for the initial term of the licence.

Ireland:

Licensing Option 11/5 Blocks 44/4, 44/5/partial, 44/9, 44/10, 44/14 and 44/15 – Antrim is required to complete a work program by October 2013 that includes seismic procurement and reprocessing, design of a new 3D survey and nominal well, perform scoping economics, and mapping of leads and prospects. A large portion of this work programme has been completed.

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

The Statement of Reserves Data and Other Oil and Gas Information of Antrim Energy Inc. presented in Schedule "A" hereto uses reserves data presented by McDaniel in the McDaniel Report, which is incorporated by reference in this AIF.

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

The report of Antrim's management and directors on the oil and gas disclosure presented herein is attached as Schedule "C" hereto and is incorporated by reference in this AIF.

DIVIDEND POLICY

Antrim has not paid any dividends on its Common Shares to the date hereof. It is the present policy of the board of directors of Antrim to retain any earnings to finance the growth and development of Antrim's business and therefore Antrim does not anticipate paying any dividends in the immediate or foreseeable future.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of Antrim consists of an unlimited number of Common Shares and an unlimited number of Preferred Shares issuable in series. As at December 31, 2012, there were 184,731,076 Common Shares issued and outstanding. No Preferred Shares are issued and outstanding.

The following is a summary of the rights, privileges, restrictions and conditions attaching to each class of shares of Antrim.

Common Shares

The holders of Common Shares are entitled to: (i) receive notice of and to vote at every meeting of shareholders of Antrim and shall have one vote thereat for each such Common Share so held, (ii) receive any dividend declared on the Common Shares by Antrim subject to the rights of the holders of Preferred Shares; and (iii) subject to the rights, privileges, restrictions and conditions attached to the Preferred Shares, receive the remaining property of Antrim on dissolution, liquidation or winding up.

Preferred Shares

Preferred Shares may, from time to time, be issued in one or more series, each series to consist of such number of shares as may, before the issue thereof, be fixed by the directors of Antrim. The directors may additionally determine the designation, rights, privileges, restrictions and conditions attaching to the Preferred Shares, including, without limiting the generality of the foregoing, the rate or amount of preferential dividends and the date of payment thereof, the redemption purchase and/or conversion price and conditions of redemption, purchase and/or conversion, if any, and any sinking fund or other provisions. The Preferred Shares rank in priority to the Common Shares as to payment of dividends and the distribution of assets in the event of dissolution, liquidation or winding-up.

Shareholder Rights Plan

At the 2010 annual meeting of shareholders, shareholders approved Antrim's Shareholder Rights Plan Agreement (the "**Rights Plan**") approved by the Board of Directors on May 27, 2010. Among other things, the Rights Plan was created to ensure, to the extent possible, that all shareholders of Antrim are treated fairly in connection with any take-over offer or bid for the common shares of Antrim, and to ensure that the Board of Directors is provided with sufficient time to evaluate unsolicited take-over bids and to explore and develop alternatives to maximize shareholder value.

The Rights Plan is not intended to prevent take-over bids. Under the Rights Plan, those bids that meet certain requirements intended to protect the interests of all shareholders are deemed to be permitted bids ("**Permitted Bids**"). Permitted Bids must be made by way of a take-over bid circular prepared in compliance with applicable securities laws and remain open for sixty days.

Under the Rights Plan, rights have been issued and attached to all common shares of the Company issued and outstanding as of the close of business on May 27, 2010. Rights will be issued upon any future issuance of any common shares of the Company that occurs prior to certain events.

MARKET FOR SECURITIES

The Common Shares of the Company are listed for trading on the TSX under the symbol "AEN" and on the Alternative Investment Market of the London Stock Exchange (AIM) under the symbol "AEY".

The following table sets out the high and low price for board lot trades and the volume of trading of the Common Shares on the TSX for the periods indicated.

	Price Range (Cdn $)		**Daily Average**
	High	**Low**	**Trading Volume**
2012			
January	1.49	1.13	442,343
February	1.42	0.96	396,155
March	1.18	0.96	395,309
April	0.97	0.75	135,640
May	0.87	0.59	84,436
June	0.72	0.47	63,095
July	0.75	0.57	102,467
August	0.79	0.60	218,268
September	0.87	0.76	97,905
October	0.86	0.75	200,618
November	0.86	0.60	194,109
December	0.65	0.49	673,095
2013			
January	0.63	0.51	185,450
February	0.53	0.48	226,174
March 1 to 22	0.50	0.43	178,788

DIRECTORS AND EXECUTIVE OFFICERS

The following table sets forth the names, municipalities of residence, positions with Antrim, time served as a director (if applicable) and the principal occupation during the last five years of the directors and executive officers of Antrim. Directors are elected at the annual meetings of shareholders and serve until the next annual meeting or until a successor is elected or appointed.

Name and Municipality of Residence	Office Held	Principal Occupation During the Last Five Years
Stephen E. Greer M.D. of Foothills, Alberta	President, Chief Executive Officer and Director since September 29, 1999.	Chief Executive Officer of Antrim.
Gerry Orbell(1)(3)(4)(5) West Sussex, England	Chairman of the Board of Directors and director since October 15, 2002.	Chairman of Antrim. Chairman and Chief Executive Officer, Sound Oil plc. from February 2005 to October 2012.
Jay Zammit(2)(5) Calgary, Alberta	Director since May 12, 2004.	Partner, Burstall Winger LLP (Barristers and Solicitors)
Jim Perry(1)(3)(4)(5) Calgary, Alberta	Director since February 15, 2005.	President, Alternative Fuel Systems business unit of IMPCO Technologies Canada, Inc.
Erik Mielke London, England	Director since May 24, 2012.	Independent director since May 2012, Vice President Business Development, Buried Hill Energy since September 2012. Prior thereto, a Partner at Namir Capital Management LLC from January 2011 to September 2012. Prior thereto, Managing Director, Merrill Lynch from May 2005 to August 2009.
Colin Maclean(2)(3)(4)(5) Edinburgh, Scotland	Director since May 20, 2008.	Independent director since November 2008. Prior thereto Business Unit Leader Refining, British Petroleum plc from January 1998 to January 2008.
James C. Smith(1)(2)(5) Calgary, Alberta	Director since November 14, 2008.	Independent director to a number of public and private oil and gas companies.
Anthony Potter Calgary, Alberta	Chief Financial Officer since March 1, 2013.	Chief Financial Officer since March 2013. Prior thereto the Vice President, Finance and Chief Financial Officer of Madalena Ventures Inc. from February 2010 to February 2013. Prior thereto, Chief Financial Officer at Antrim from 2003 to August 2008.
Kerry Fulton Calgary, Alberta	Vice President, Operations since October 1, 2008.	Vice-President Operations since October 2008. Prior thereto, Chief Operating Officer of Antrim.
Terry Lederhouse Calgary, Alberta	Vice President, Commercial since January 1, 2010.	Vice-President, Commercial since January, 2010. Prior thereto, Commercial Manager of Antrim.
Martin Dashwood Calgary, Alberta	Vice President, Exploration since May 1, 2012.	Vice-President, Exploration since May 1, 2012. Prior thereto, Exploration Manager of Antrim.

Name and Municipality of Residence	Office Held	Principal Occupation During the Last Five Years
Adrian Harvey Calgary, Alberta	Corporate Secretary since May 11, 2011	Associate, Burstall Winger LLP since June 2010. Prior thereto, associate with Blake, Cassels & Graydon LLP.

Notes:

1. Member of the Audit Committee.
2. Member of the Compensation Committee.
3. Member of the Reserves Committee.
4. Member of the Exploration Committee.
5. Member of the Corporate Governance Committee.
6. The Company does not have an Executive Committee.

As of December 31, 2012, the directors and executive officers of the Company as a group, beneficially owned, directly or indirectly, or exercised control or direction over 3,344,709 Common Shares or approximately 1.8% of the issued and outstanding Common Shares. In addition, the directors and officers of Antrim held options entitling them as a group to acquire an additional 9,060,000 Common Shares as of December 31, 2012.

Other than as set forth below, no director, executive officer of the Company or a shareholder holding a sufficient number of securities of Antrim to affect materially the control of Antrim, or any personal holding company of any such person, is as of the date hereof or was in the 10 years before the date hereof, a director or executive officer of any company (including Antrim) that while that person was acting in that capacity:

- was the subject of a cease trade order or similar order or an order that denied the company access to any exemption under applicable securities legislation, for a period of more than 30 consecutive days and which resulted from an event that occurred while that person was acting in the capacity as a director executive officer or after the director or executive officer ceased to be a director or executive officer, in the company; or

- or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

On August 30, 2005, Jay Zammit became a director of Marine Bioproducts International Corp. ("**Marine**"), a company listed on the NEX Board of the TSX Venture Exchange Inc. that was the subject of a cease trade order in British Columbia and Alberta prior to Mr. Zammit's appointment. Mr. Zammit was appointed to the board to assist in the reinstatement of Marine to good standing. Marine successfully completed an equity financing on May 5, 2006 and on May 9, 2006, it successfully completed a Statutory Plan of Arrangement under the *Business Corporations Act* (Alberta) with Phoenix Oilfield Hauling Ltd., Alberta Loader Rentals Inc. and EMJ Consulting Ltd. (the "**Phoenix Group**") whereby Marine exercised options to purchase the Phoenix Group and whereby it changed its name to Phoenix Oilfield Hauling Inc. The cease trade orders against Marine were lifted on June 2, 2006. Mr. Zammit resigned as a director of Phoenix Oilfield Hauling Inc. on December 18, 2008.

Jim Perry was the President, Chief Executive Officer and a Director of Alternative Fuel Systems Inc. and Mr. Jay Zammit was Corporate Secretary of Alternative Fuel Systems Inc. when it made an application under the *Companies' Creditors Arrangement Act* (Canada) (the "**CCAA**"). Alternative Fuel Systems Inc. completed a Statutory Plan of Arrangement under the CCAA and the Alberta Business Corporations Act on June 30, 2004 whereby the company was reorganized into two companies: Alternative Fuel Systems (2004) Inc. ("**AFS (2004)**") and AFS Energy Inc. AFS Energy Inc. completed a transaction to convert to an oil and gas company and changed its name to Flagship Energy Inc. (which now operates as Insignia Energy Ltd.) effective May 2005. AFS 2004 completed a private placement financing in 2005 and remained listed on the TSX Venture Exchange until being acquired by Fuel Systems Solutions Inc. ("FSS") in June 2011. Mr. Perry is now the President of Alternative Fuel Systems, a business unit of IMPCO Technologies Canada, Inc. a subsidiary of FSS and is no longer associated with Flagship Energy Inc. or its successors. Mr. Zammit ceased to be a director of AFS (2004) upon the company's acquisition by FSS in June of 2011 and is no longer associated with AFS (2004), Flagship Energy Inc. or its successors.

No director, executive officer or proposed director of the Company or a shareholder holding a sufficient number of securities of Antrim to affect materially the control of Antrim, or any personal holding company of any such person, has, in the 10 years prior to the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold their assets.

No director, executive officer or proposed director of the Company or a shareholder holding a sufficient number of securities of Antrim to affect materially the control of Antrim, or any personal holding company of any such person, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable security holder in making an investment decision.

Conflicts Of Interest

There are potential conflicts of interest to which the directors and officers of the Company or its subsidiaries may be subject in connection with the operations of the Company or its subsidiaries. Some of the directors and officers are engaged and will continue to be engaged, directly or indirectly, in other businesses and situations may arise where some of the directors and officers will be in direct competition with the Company or its subsidiaries. Jay Zammit, a director of the Company is a partner with Burstall Winger LLP, which provides legal services to the Company on a fee for services basis. Conflicts, if any, will be subject to the procedures and remedies under the *Business Corporations Act* (Alberta).

AUDIT COMMITTEE INFORMATION

The full text of the audit committee charter is included in Schedule “D” of this Annual Information Form.

Composition of the Audit Committee

The audit committee consists of three members, each of whom is financially literate and independent. The relevant education and experience of each audit committee member is outlined below.

James C. Smith

Mr. Smith is a Chartered Accountant with over 40 years of experience in public accounting and industry. Since 1998, he has been a business consultant to a number of public and private companies operating in the oil and gas industry. From 2002 until its sale in 2006, he was also the Chief Financial Officer of Mercury Energy Corporation, a private oil and natural gas company, and from 2001 until the sale of the company in 2003, was the Chief Financial Officer of Segue Energy Corporation, a private oil and natural gas company. From 1999 to 2000, Mr. Smith was the Vice President and Chief Financial Officer of Probe Exploration Inc., a publicly traded oil and natural gas company. While Mr. Smith was the Vice President and Chief Financial Officer of Crestar Energy Inc. from its inception in 1992 until 1998, the company completed an initial public offering, was listed on the TSX and completed several major debt and equity financing transactions. Mr. Smith is currently a director of Penn West Petroleum Ltd.

Jim Perry

Mr. Perry is a graduate of the University of British Columbia, with a degree in Mineral Engineering. He is a Registered Professional Engineer in the Province of Alberta.

Mr. Perry served as Administrative Manager and Controller of the Schlumberger-Doll Research Center in Ridgefield, Connecticut from 1978 through 1979, during which time he was directly in charge of all accounting for a research laboratory with a staff of more than 100 people. He has served as President of a number of public companies, including Computalog Ltd., Global Thermoelectric Inc., and Alternative Fuel Systems Inc. In these positions, he directly supervised the Chief Financial Officer of each company.

Gerry Orbell

Mr. Orbell, B.Sc, Ph.D is currently Chairman of Antrim. From 2005 to 2012, Mr. Orbell served as Chairman and Chief Executive Officer of Sound Oil plc, a United Kingdom public company listed on the Alternative Investment Market of the

London Stock Exchange. He has served as an executive director of a number of companies, including Premier Oil plc and United Utilities plc. For the last nine years Dr. Orbell has been Chairman of the Audit Committee of Valpak Ltd, an environmental compliance company in the UK.

Pre-Approval Policies and Procedures

Antrim has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by PricewaterhouseCoopers LLP. The audit committee of the Board of Directors has established a budget for the provision of a specified list of audit and permitted non-audit services that the audit committee believes to be typical, recurring or otherwise likely to be provided by PricewaterhouseCoopers LLP. The budget generally covers the period between the adoption of the budget and the next meeting of the audit committee, but at the option of the committee may cover a longer period. The list of services is sufficiently detailed as to ensure that (i) the audit committee knows what services it is being asked to pre-approve and (ii) it is not necessary for any member of management to make a judgment as to whether a proposed service fits within the pre-approved services. All proposed services that have not already been pre-approved must be pre-approved by the audit committee.

External Auditor Service Fees

The following table provides information about the fees billed to the Company for professional services rendered by PricewaterhouseCoopers LLP during fiscal 2012 and 2011:

	2012	2011
Audit Fees	$ 215,935	$ 244,414
Audit-Related Fees (1)	99,777	80,410
Tax Fees (2)	24,396	80,434
All Other Fees (3)	57,702	41,041
Total(4)	$ 397,810	$ 446,299

Notes:

(1) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements and are not reported as audit fees.

(2) Tax fees consist of fees for tax compliance services, tax advice and planning and transfer pricing studies

(3) All other fees consist of fees for internal controls review and advice on accounting standards.

(4) Fees of $92,800 relating to the sale of Antrim Argentina S.A are included in this total.

LEGAL PROCEEDINGS

Antrim may be involved in litigation from time to time in the ordinary course of its business. Although Antrim is not currently a party to any legal proceedings, except as described in Note 21 of the Company's annual financial statements for the year ended December 31, 2012, legal proceedings could be filed against Antrim in the future. No assurances can be given as to the final outcome of any legal proceedings or that the ultimate resolution of any legal proceedings will not have a material adverse effect on Antrim.

Antrim is not a party to nor is any of its property the subject of any other legal proceedings nor, to the knowledge of management of Antrim, are any such proceedings known to be contemplated.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive officer of the Company or any person or company that is the direct or indirect beneficial owner of or exercises control or direction over more than 10 percent of the Common Shares, or an associate or affiliate of any such person, has or has had any material interest, direct or indirect, in any transaction within the three most recently completed financial years of Antrim or during the current financial year that has materially affected or will materially affect Antrim.

TRANSFER AGENT AND REGISTRAR

CIBC Mellon Trust Company, at its principal offices in Calgary, Alberta and Toronto, Ontario, is the transfer agent and registrar for the Common Shares and warrants of the Company.

MATERIAL CONTRACTS

Except as noted below, Antrim has not entered into any contract, other than contracts entered into in the ordinary course of business, that is material to Antrim and that was entered into within the most recently completed financial year or before the most recently completed financial year but is still in effect (other than contracts entered into before January 1, 2002).

Payment Swap Financing and Commodity Swap

On January 23, 2013, Antrim entered into a $30 million Payment Swap transaction and a 29 month Brent oil price Commodity swap transaction for 657,350 barrels at $89.37.

INTERESTS OF EXPERTS

The Company’s auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have prepared an independent auditors’ report dated March 26, 2013 in respect of the Company’s consolidated financial statements with accompanying notes as at and for the years ended December 31, 2012 and 2011. PricewaterhouseCoopers LLP have advised that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

McDaniel & Associates Consultants Ltd. is responsible for the report on the Company’s reserves in the United Kingdom. McDaniel has advised that partners and associates of McDaniel had no direct or indirect beneficial interest in any securities or other property of the Company or its associates or affiliates at the time when such report was prepared, nor have they received after such time or are to receive any such interest. No director, officer or employee of McDaniel is or is expected to be elected, appointed or employed as a director, officer or employee of Antrim or any of its associates or affiliates.

ADDITIONAL INFORMATION

Additional information regarding the Company may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness to the Company, principal holders of securities of the Company and securities authorized for issuance under equity compensation plans is contained in the Company’s Information Circular prepared in connection with the annual and special meeting of shareholders held May 24, 2012 (the “**Information Circular**”). Additional financial information is provided in the Company's comparative financial statements for its financial year ended December 31, 2012, together with the accompanying report of the auditor and management’s discussion and analysis filed on SEDAR.

SCHEDULE "A" – FORM 51-101F1 STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION OF ANTRIM ENERGY INC.

Part 1 Date of Statement

Item 1.1 Date of Statement and Statement Information

This Statement of Reserves Data and Other Oil and Gas Information (the "**Statement**") is dated March 26, 2013. The effective date of the information provided in the Statement is December 31, 2012 unless otherwise indicated. 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.

Part 2 Disclosure of Reserves Data

McDaniel has prepared the McDaniel Report, in which it has evaluated as at December 31, 2012 the oil and natural gas reserves attributable to the Company's licence areas in the United Kingdom.

The McDaniel Report presents the estimated value of future net revenue from Antrim's properties before and after taxes, at various discount rates. Assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes to the following tables.

The extent and nature of all information supplied by Antrim and/or the operator of its properties, which may have included ownership data, well information, geological information, reservoir studies, timing and future production, gas sales contract information, current product prices, operating cost data, capital budget forecasts and future operating plans, have been relied upon by McDaniel in preparing the McDaniel Report and were accepted as represented without independent verification. In the absence of such information, McDaniel relied, with the approval of Antrim, upon its opinion of reasonable practice in the industry. All information provided to McDaniel was as at December 31, 2012 and, accordingly, certain of such information may not be representative of current conditions.

It should not be assumed that the present worth of estimated future net revenue represents the fair market value of the reserves. There is no assurance that the forecast prices and costs contained in the McDaniel Report will be attained and variances could be material. The reserve and future net revenue estimates set forth below are estimates only and the actual reserves and realized net revenue may be greater or less than those calculated.

All dollar figures are presented in U.S. dollars which were used in the McDaniel Report.

Item 2.1 Reserves Data Using Forecast Prices and Costs

The following table discloses, by country and in the aggregate, the Company's gross and net proved and probable reserves, estimated using forecast prices and costs, by product type. "Forecast prices and costs" means future prices and costs used by McDaniel in the McDaniel Report that are either generally accepted as being a reasonable outlook of the future, or fixed or currently determinable future prices or costs to which the Company is legally bound to deliver a physical product such as oil or natural gas.

	Antrim's Interest in Reserves[(1)(2)(6)]							
	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	Gross[(3)]	Net[(4)]	Gross[(3)]	Net[(4)]	Gross[(3)]	Net[(4)]	Gross[(3)]	Net[(4)]
United Kingdom								
Proved:								
Developed Producing[(5)]	569	478	-	-	-	-	-	-
Developed Non-Producing	63	47	-	-	-	-	-	-
Undeveloped	204	204	-	-	-	-	-	-
Total Proved	836	729	-	-	-	-	-	-
Probable	15,789	15,789	-	-	-	-	-	-
Total Proved plus Probable	16,626	16,519	-	-	-	-	-	-
Total								
Proved:								
Developed Producing[(5)]	569	478	-	-	-	-	-	-
Developed Non-Producing	63	47	-	-	-	-	-	-
Undeveloped	204	204	-	-	-	-	-	-
Total Proved	836	729	-	-	-	-	-	-
Probable	15,789	15,789	-	-	-	-	-	-
Total Proved plus Probable	16,626	16,519	-	-	-	-	-	-

The following table discloses, by country and in the aggregate, the net present value of the Company's future net revenue attributable to the reserves categories in the previous table, estimated using forecast prices and costs, before and after deducting future income tax expenses, and calculated without discount and using discount rates of 5%, 10%, 15% and 20%.

	Net Present Value of Future Net Revenue[(1)(2)(6)]									
	Before Income Taxes, discounted at %/year ($,000)					After Income Taxes, discounted at %/year ($,000)				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
United Kingdom										
Proved:										
Developed Producing	34,644	33,735	32,880	32,074	31,316	34,644	33,735	32,880	32,074	31,316
Developed Non-Producing	3,314	3,208	3,110	3,020	2,937	3,118	3,024	2,938	2,858	2,784
Undeveloped	3,128	2,139	1,257	474	(218)	3,128	2,139	1,257	474	(218)
Total Proved	41,087	39,082	37,247	35,569	34,035	40,890	38,898	37,074	35,407	33,882
Probable	387,553	317,999	262,579	217,985	181,774	324,676	264,628	217,102	179,057	148,284
Total Proved plus Probable	428,640	357,081	299,825	253,554	215,808	365,566	303,526	254,177	214,464	182,166
Total										
Proved:										
Developed Producing	34,644	33,735	32,880	32,074	31,316	34,644	33,735	32,880	32,074	31,316
Developed Non-Producing	3,314	3,208	3,110	3,020	2,937	3,118	3,024	2,938	2,858	2,784
Undeveloped	3,128	2,139	1,257	474	(218)	3,128	2,139	1,257	474	(218)
Total Proved	41,087	39,082	37,247	35,569	34,035	40,890	38,898	37,074	35,407	33,882
Probable	387,553	317,999	262,579	217,985	181,774	324,676	264,628	217,102	179,057	148,284
Total Proved plus Probable	428,640	357,081	299,825	253,554	215,808	365,566	303,526	254,177	214,464	182,166

This table discloses, by production group, the net present value of the Company's future net revenue attributable to its proved reserves and its proved plus probable reserves, before deducting future income tax expenses, estimated using forecast prices and costs and calculated using a 10% discount rate.

Production Group	**Net Present Value of Future Net Revenue Before Future Income Tax Expense, Calculated using a 10% Discount Rate (1)(2)(6)**			
	Proved Reserves		**Proved Plus Probable Reserves**	
	($,000)	**Unit Value ($)**	**($,000)(7)(8)**	**Unit Value ($)**
Light and Medium Oil	37,247	$51.06 / bbl	299,825	$18.15/ bbl
Heavy Oil	-	-	-	-
Natural Gas	-	-	-	-
Natural Gas Liquids	-	-	-	-
Total	37,247		299,825	

Notes:
(1) Totals may not add due to rounding.
(2) The definitions of the various categories of reserves and expenditures are those set out in NI 51-101.
(3) "Gross" reserves refer to Antrim's working interest share before deducting royalties and without including any of the Company's royalty interests.
(4) "Net" reserves refer to Antrim's working interest share after deducting royalties plus the Company's royalty interests. The royalties deducted from the reserves are based on the royalty percentage calculated by applying the applicable royalty rate or formula.
(5) All of the Proved Developed Producing Reserves evaluated in the McDaniel Report were on production at January 1, 2013.
(6) Future Income Tax Expenses includes "Abandonment Tax Relief" for the United Kingdom.
(7) Includes 1,727 Mbbls of Proved plus Probable Reserves in the Fionn Field with a before tax net present value using a 10% discount rate of $58,451,000, which were relinquished in January 2013.
(8) Includes 11,758 Mbbls of Proved plus Probable Reserves in the Fyne and Crinan Fields with a before tax net present value using a 10% discount rate of $96,466,000, which the Company discontinued development of on March 26, 2013.

The following two tables provide additional information regarding the future net revenue attributable to total proved reserves outlined in the previous table.

This table discloses, by country and in the aggregate, certain elements of the Company's future net revenue attributable to its proved reserves and its proved plus probable reserves, estimated using forecast prices and costs and calculated without discount.

Elements of Future Net Revenue Using Forecast Prices and Costs, Calculated without Discount(1)(2)(6)(7)	**United Kingdom ($,000)**	**Total ($,000)**
Proved Reserves		
Revenue	77,274	77,274
Royalties	-	-
Operating costs	15,947	15,947
Development costs	12,281	12,281
Abandonment and reclamation costs	7,959	7,959
Future net revenue before future income tax expenses	41,087	41,087
Future income tax expenses	196	196
Future net revenue after future income tax expenses	40,890	40,890
Proved Plus Probable Reserves		
Revenue	1,555,454	1,555,454
Royalties	-	-
Operating costs	553,126	553,126
Development costs	480,616	480,616
Abandonment and reclamation costs	93,073	93,071
Future net revenue before future income tax expenses	428,640	428,640
Future income tax expenses	63,074	63,074
Future net revenue after future income tax expenses	365,566	365,566

Part 3 Pricing Assumptions

Item 3.1 Forecast Prices Used in Estimates

Year	WTI	Brent	Crude Oil Prices ($/bbl) UK Causeway[1]	UK Fyne & Crinan[2]	UK Cormorant East[3]
Antrim's actual weighted average for 2012			-	-	-
Benchmark reference price end of 2012	91.82	110.79	-	-	-
Forecast					
2013	92.50	107.50	94.72	100.63	102.36
2013	92.50	102.50	89.47	95.85	97.26
2015	93.60	101.40	88.11	94.77	96.05
2016	95.50	100.80	87.24	94.17	95.34
2017	97.40	100.10	86.27	93.47	94.54
2018	99.40	102.20	88.09	95.43	96.52
2019	101.40	104.20	89.81	97.30	98.41
2020	103.40	106.30	91.62	99.26	100.39
2021	105.40	108.30	93.33	101.13	102.28

The escalating price and cost assumptions assume the continuance of current laws and regulations and increases in wellhead selling prices, and take into account inflation with respect to future operating capital costs. In the McDaniel Report, future operating and capital costs are assumed to escalate at 2% per annum.

Notes:

(1) Includes deductions for host platform and pipeline tariffs

(2) Includes deductions for quality differential and shuttle tanker cost

(3) Includes deductions for pipeline and terminal tariffs

Part 4 Reconciliation Of Changes In Reserves And Future Net Revenue Reserves Reconciliation

Item 4.1 Reserves Reconciliation

The following table summarizes the changes during the year ended December 31, 2012 in Antrim's gross reserves in the United Kingdom from its properties evaluated in the McDaniel Report, based on forecast prices and costs. See notes to preceding tables for information regarding forecast prices and costs.

	United Kingdom Light and Medium Crude Oil (Mbbl)			United Kingdom Natural Gas (MMcf)			United Kingdom Natural Gas Liquids (Mbbl)		
	Gross Proved	Gross Probable	Total Gross Proved plus Probable	Gross Proved	Gross Probable	Total Gross Proved plus Probable	Gross Proved	Gross Probable	Total Gross Proved plus Probable
Opening Balance – (1)(2)(3)									
December 31, 2011	721	11,885	12,606	-	-	-	-	-	-
Plus:									
Extensions	-	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-	-
Technical revisions	142	(3,518)	(3,375)	-	-	-	-	-	-
Discoveries	63	548	611	-	-	-	-	-	-
Acquisitions	-	6,874	6,874	-	-	-	-	-	-
Less:									
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-
Production	(90)	-	(90)	-	-	-	-	-	-
Ending Balance – December 31, 2012	837	15,789	16,626	-	-	-	-	-	-

Notes:
(1) Totals may not add due to rounding.
(2) "Gross reserves" refer to Antrim's working interest share before deducting royalties. No royalties are paid in the United Kingdom.
(3) Reserves reconciliation in the AIF for year ended December 31, 2011 was based on forecast prices and costs.

The following table summarizes the changes during the year ended December 31, 2012 in Antrim's gross reserves in Argentina from its properties evaluated in the McDaniel Report, based on forecast prices and costs. See notes to preceding tables for information regarding forecast prices and costs.

	Argentina Light and Medium Crude Oil (Mbbl)			**Argentina Natural Gas (MMcf)**			**Argentina Natural Gas Liquids (Mbbl)**		
	Gross Proved	**Gross Probable**	**Total Gross Proved plus Probable**	**Gross Proved**	**Gross Probable**	**Total Gross Proved plus Probable**	**Gross Proved**	**Gross Probable**	**Total Gross Proved plus Probable**
Opening Balance – (1)(2)(3) December 31, 2011	581	379	960	17,987	10,642	28,629	245	85	330
Plus:									
Extensions	-	-	-	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-	-
Technical revisions	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Less:									
Dispositions	(546)	(379)	(925)	(16,954)	(10,642)	(27,596)	(235)	(85)	(320)
Economic factors	-	-	-	-	-	-	-	-	-
Production	(35)	-	(35)	(1,033)	-	(1,033)	(10)	-	(10)
Ending Balance – December 31, 2012	-	-	-	-	-	-	-	-	-

Notes:
(1) Totals may not add due to rounding.
(2) "Gross reserves" refer to Antrim's working interest share before deducting royalties. In the case of Argentina, an 11.8% provincial royalty is paid until the licence extension was assumed to be granted in mid-2012 and then provincial royalty increases to 14.3 percent thereafter.
(3) Reserves reconciliation in the AIF for the year ended December 31, 2011 was based on forecast prices and costs.

Part 5 Additional Information Relating To Reserves Data

Item 5.1 Proved Undeveloped and Probable Undeveloped Reserves

Proved undeveloped and probable undeveloped reserves have been attributed to Antrim's interests as of December 31, 2012 and as of December 31 of the previous three years as follows.

	As of December 31, 2012			
	Light/Medium Oil		**Natural Gas**	
Proved Undeveloped	**1st Attributed (Mbbl)**	**Booked (Mbbl)**	**1st Attributed (MMcf)**	**Booked (MMcf)**
Prior to 2010	-	-	-	-
2010	-	-	-	-
2011	721	721	-	-
2012	63	204	-	-

Probable Undeveloped	1st Attributed (Mbbl)	Booked (Mbbl)	1st Attributed (MMcf)	Booked (MMcf)
Prior to 2010	27,726	27,726	-	-
2010	-	27,726	-	-
2011	-	11,885	-	-
2012	2,314	15,789	-	-

Note:
(1) Probable undeveloped locations and reserves for the U.K. include wells drilled but not yet completed and tied in.

United Kingdom

Probable undeveloped reserves were assigned to the Fyne and Crinan property. The reserves were assigned based on the existing nine wells and three successful flow tests, the 3D seismic acquired and interpreted in 2007, two multi-lateral wells drilled in 2008, and the well drilled in 2012. These reserves were to be developed over the next four years, however subsequent to December 31, 2012 the Company discontinued development of the Fyne Field due to escalating costs.

Probable undeveloped reserves were assigned to the four mapped fault blocks in Causeway, Fionn and West Causeway based on the successful drilling of six wells from 2006 to 2008, and the two previous wells which successfully tested oil. Three of the six wells drilled from 2006 to 2008 successfully tested oil. The other three wells were not production tested as sufficient information was already available from adjacent wells. These reserves will be developed over the next four years, with drilling to resume after oil production has started in the first phase of development. Subsequent to December 31, 2012, the Company announced that it had elected to opt out of participating in further development of the Fionn Field. The projected costs associated with the development of Fionn had increased to the extent that the project no longer met Antrim's economic criteria.

Probable undeveloped reserves were assigned to the Cormorant East Field based on the successful well drilled in 2012, the seismic interpretation of the operator, and the production history from analogous adjacent fields.

Item 5.2 Significant Factors or Uncertainties

Estimates of oil and natural gas reserves and their values by petroleum engineers are inherently uncertain. Reserve estimates are based on evaluations of geological, engineering, production and economic data. These estimates are based on professional judgments about a number of elements and such professional judgments may vary as among different petroleum engineers. These estimates include:

- The amount of recoverable crude oil and natural gas present in a reservoir.
- The costs that will be incurred to produce the crude oil and natural gas.
- The rate at which production will occur.

The data can change over time due to, among other things:

- Additional development activity.
- Evolving production history.
- Changes in production costs, market prices and economic conditions.

As a result, the actual amount, cost and rate of production of oil and gas reserves and the revenues derived from sale of the oil and gas produced in the future will vary from those anticipated in the McDaniel Report as of December 31, 2012. The magnitude of those variations may be material.
All of Antrim's reserves are located outside of Canada. Accordingly, Antrim's reserve estimates are subject to additional risks and uncertainties. See "Business of Antrim – Risks of Foreign Operations".

Item 5.3 Future Development Costs

The following table provides information regarding the development costs deducted in the estimation of future net revenue set out under the headings “Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data - Reserves Data Using Forecast Prices and Costs”, by country and reserves category.

United Kingdom[(1)(2)]

Year/Item	**Proved Reserves (forecast prices and costs) ($,000)**	**Proved plus Probable Reserves (forecast prices and costs) ($,000)**
2013	12,281	79,819
2014	-	188,150
2015	-	63,568
2016	-	140,610
2017	-	-
remaining years	-	8,468
Total, undiscounted	12,281	480,615

Notes:
(1) The definitions of the various categories of reserves and expenditures are those set out in NI 51-101.
(2) See notes to tables under the headings “Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data - Reserves Data Using Forecast Prices and Costs” regarding forecast prices and costs.

The Company expects that such funds will be obtained from combinations of existing working capital, internally-generated cash flow, new equity and debt instruments.

Part 6 Other Oil and Gas Information

Item 6.1 Oil and Gas Wells

The following table shows information regarding the Company’s wells at December 31, 2012.

	Producing Wells[(1) (2)]				**Non-Producing Wells[(1)(2)]**			
	Crude Oil		**Natural Gas**		**Crude Oil**		**Natural Gas**	
	Gross[(3)]	**Net[(4)]**	**Gross**	**Net**	**Gross[(3)]**	**Net[(4)]**	**Gross**	**Net**
United Kingdom [(4)]	1	0.4	-	-	8	3.8	-	-
Total	1	0.4	-	-	8	3.8	-	-

Notes:
(1) The definitions of the various categories of reserves and wells are those set out in NI 51-101.
(2) Two of the eleven wells drilled and not abandoned in the U.K. since 2006 are Producing, seven are considered Non-Producing, and two will be used for pressure maintenance.
(3) “Gross wells are defined as the total number of wells in which Antrim has an interest.
(4) “Net” wells are defined as the total number of wells obtained by aggregating Antrim’s working interest in each of its gross wells.

Item 6.2 Properties with No Attributed Reserves

The following table sets forth information respecting Antrim's unproved properties as at December 31, 2012.

Country	Project	Working Interest (%)	Acreage Gross[(1)]	Acreage Net[(2)]
United Kingdom	Block 211/22a Kerloch Area	13.65	12,550	1,713
	Block 21/24b	100.0	36,003	36,003
	Block 21/29d	50.0	27,095	13,548
	Blocks 21/28b & 29c [(3)]	100.0	49,174	49,174
	Blocks 21/7b	30.0	43,225	21,613
Total			168,047	122,051

Notes:
(1) "Gross" acres are defined as the total area of properties in which Antrim has an interest.
(2) "Net" acres are defined as the total area in which Antrim has an interest multiplied by the working interest owned by Antrim.
(3) Licence P1563 Blocks 21/28b and 21/29c was relinquished in February 2013

McDaniel completed a resource assessment of the Kerloch Area Licence in Block 211/22a North West Area in 2007, following the drilling of well 211/22a-10. No additional independent evaluation has been performed. The results of McDaniel's November 2007 assessment were an assignment of Contingent Resources as follows [(1) (2) (3) (4) (5) (6) (7)].

Contingent Resources:

Property	1C Low Estimate Mbbl	2C Best Estimate Mbbl	3C High Estimate Mbbl
Kerloch	3,056	5,112	8,554
Net to Antrim	642	1,074	1,796

Notes:
(1) The definitions of the various categories of contingent resources are those set out in the Canadian Oil and Gas Evaluation Handbook:
   - Contingent Resources are 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. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be sub classified based on project maturity and/or characterized by their economic status.
   - Low Estimate is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
   - Best Estimate is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
   - High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.
(2) All products are expected to be classified as Light and Medium Crude Oil.
(3) This estimate of contingent resources was based on a probabilistic analysis using a log normal distribution of the key input parameters, a methodology commonly used to estimate resources.
(4) The estimates of remaining recoverable contingent resources have not been adjusted for risk based on the chance of development. It is not an estimate of volumes that may be discovered. Actual recovery may be less.
(5) The effective date of the estimate of Contingent Resources is December 31, 2007. There has been no subsequent resource assessment.
(6) No flow test was conducted on well 211/22a-10, however cores, wireline logs, reservoir pressure measurements and fluid samples were taken. A considerable number of tests have been completed in a nearby and geologically comparable known accumulation, specifically in Antrim-operated Causeway wells 211/23d-17Z, 211/22a-6 and 211/22a-8.
(7) The contingencies precluding the contingent resources for Kerloch from being classified as reserves are economic. There is no infrastructure currently available within a reasonable distance to Kerloch that will facilitate the economic development of the

volume of resources assessed. Future development in the area could provide the required infrastructure to render a development at Kerloch economic.

Antrim completed an internal resources assessment of the blocks acquired in the 25th and 26th Seaward Licence Rounds in the area adjacent to and north of the Fyne Field: Blocks 21/24b, 21/29d, 21/28b, 21/29, 21/7b Based on that internal resources assessment, an assignment of Prospective Resources was made as follows [(1) (2) (3) (4) (5) (6) (7)].

Prospective Resources:

Property	Low Estimate Mbbl	Best Estimate Mbbl	High Estimate Mbbl
Central North Sea	23,300	50,700	111,600
Net to Antrim	20,500	46,500	105,200

Notes:

(1) The definitions of the various categories of prospective resources are those set out in the Canadian Oil and Gas Evaluation Handbook:
- Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub classified based on project maturity.
- Low Estimate is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- Best Estimate is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

(2) All products are expected to be classified as Light and Medium Crude Oil.

(3) This estimate of prospective resources was based on a probabilistic analysis using a log normal distribution of the key input parameters, a methodology commonly used to estimate resources.

(4) The estimates of remaining recoverable prospective resources have been risked for chance of discovery, but have not been risked for chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development.

(5) The Prospective Resources were estimated by Terry Lederhouse, P. Eng., Vice-President, Commercial of the Company. Mr. Lederhouse is a qualified reserves evaluator within the meaning of NI 51-101, but he is not independent in respect of the Company within the meaning of NI 51-101. The estimates were prepared in accordance with the procedures contained in the Canadian Oil and Gas Evaluation Handbook.

(6) The effective date of the estimate of Prospective Resources is December 31, 2012.

(7) There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the Prospective Resources.

Item 6.3 Forward Contracts

The Company is bound by an agreement (including a transportation agreement), under which it is precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or gas. See “Business of Antrim – Marketing Agreement, Business and Antrim –Prepayment and Commodity Swaps and Future Commitments”.

Item 6.4 Additional Information Concerning Abandonment and Restoration Costs

In deriving estimates for abandonment and restoration costs, the Company considered the geographic location of the wells and facilities in place as at December 31, 2012, the nature of the facilities and actual field experience.

Using this methodology, the Company’s total unescalated abandonment and restoration costs, net of estimated salvage value, are estimated at $11,218,000 for the United Kingdom. It is estimated that this amount should cover costs for approximately 4.1 net wells in the United Kingdom plus similar costs for the Company’s facilities and pipelines interests. All of the estimated abandonment and restoration costs were deducted in computing future net revenue. No portion of the Company’s undiscounted total abandonment and reclamation costs are expected to be paid in the next three financial years.

Item 6.5 Tax Horizon

The Company does not expect to pay cash income taxes in the United Kingdom or Canada for at least the next four years.

Item 6.6 Costs Incurred

The following table summarizes in Canadian dollars certain expenditures of the Company for the year ended December 31, 2012.

	Property Acquisition Costs ($)				
Country	**Unproved Properties**	**Proved Properties**	**Exploration Costs ($)**	**Development Costs ($)**	**Total ($)**
United Kingdom	-	-	8,528,000	54,506,000	63,034,000
Total	-	-	8,528,000	54,506,000	63,034,000

Note:
(1) The definitions of the various categories of properties and expenses are those set out in NI 51-101.

Item 6.7 Exploration and Development Activities

The following table sets forth the gross and net wells completed by Antrim during the financial year ended December 31, 2012.

Country	**Oil Wells**		**Gas Wells**		**Service Wells**		**Dry Holes**	
	Gross(2)	**Net(3)**	**Gross(2)**	**Net(3)**	**Gross(2)**	**Net(3)**	**Gross(2)**	**Net(3)**
Argentina	0	0	0	0	0	0	0	0
United Kingdom	1	.1	0	0	0	0	2	.85
Total	1	.1	0	0	0	0	2	.85

Notes:
(1) The definitions of the various categories of products and wells are those set out in NI 51-101.
(2) “Gross” wells are defined as the total number of wells in which Antrim has an interest.
(3) “Net” wells are defined as the total number of wells obtained by aggregating Antrim’s working interest in each of its gross wells.

Item 6.8 Production Estimates

Estimated production volumes derived from the first year (2013) of the cash flow forecasts prepared in conjunction with the Company's proved and proved plus probable reserves data and included in the McDaniel Report are provided in the following table.

Summary of Production Estimates for 2013 (1)

	Light and Medium Oil (Mbbl)		**Heavy Oil (Mbbl)**		**Natural Gas (MMcf)**		**Natural Gas Liquids (Mbbl)**	
	Gross(2)	**Net**(3)	**Gross**(2)	**Net**(3)	**Gross**(2)	**Net**(3)	**Gross**(2)	**Net**(3)
Proved								
United Kingdom	447	361	-	-	-	-	-	-
Probable								
United Kingdom	484	464	-	-	-	-	-	-
Total Proved + Probable	931	825	-	-	-	-	-	-

Notes:

(1) Estimated production from first year of proved plus probable producing reserves (forecast prices and costs) case in the McDaniel Report

(2) "Gross" reserves refer to Antrim's working interest share before deducting royalties and without including any of the Company's royalty interests.

(3) "Net" reserves refer to Antrim's working interest share after deducting royalties plus the Company's royalty interests.

Item 6.9 Production History

The following table summarizes the Company's average daily production volumes (before deduction of royalties) and average prices, royalties and production costs in Canadian dollars on a quarterly basis during the financial year ended December 31, 2012.

Product Type/Item[1][4]	Argentina[5] Year Ended December 31, 2012				United Kingdom[6] Year Ended December 31, 2012			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Light and Medium Crude Oil								
-average daily production volumes, before royalties (bbl/d)	220	319	-	-	-	-	-	1,194
-average price received ($/bbl)[2]	68.72	70.09	-	-	-	-	-	-
-average royalties paid ($/bbl)	10.83	9.43	-	-	-	-	-	-
-average production costs ($/bbl) [3]	9.85	7.41	-	-	-	-	-	-
-netback ($/bbl)	48.04	53.24	-	-	-	-	-	-
Natural Gas, Excluding NGL's								
-average daily production volumes, before royalties (Mcfpd)	6,018	3,976	-	-	-	-	-	-
-average price received ($/Mcf)	2.44	2.38	-	-	-	-	-	-
-average royalties paid ($/Mcf)	0.38	0.27	-	-	-	-	-	-
-average production costs ($/Mcf) [3]	1.61	1.66	-	-	-	-	-	-
-netback ($/Mcf)	0.44	0.44	-	-	-	-	-	-
Natural Gas Liquids								
-average daily production volumes, before royalties (bbl/d)	66	65	-	-	-	-	-	-
-average price received ($/bbl)	18.39	21.53	-	-	-	-	-	-
-average royalties paid ($/bbl)	2.90	8.82	-	-	-	-	-	-
-average production costs ($/bbl)	9.67	9.98	-	-	-	-	-	-
-netback ($/bbl)	5.82	2.73	-	-	-	-	-	-

Notes:

(1) Totals may not add due to rounding.
(2) The definitions of the various categories of products and expenses are those set out in NI 51-101. After export tax.
(3) Product prices are net of quality differential and costs to transport the product to market. Represents sales of light quality crude oil. During the periods indicated Antrim did not sell any medium, heavy or synthetic crude oil.
(4) This figure includes all field operating expenses.
(5) Argentina amounts pertain to period until the sale of Antrim Argentina SA in May, 2012
(6) United Kingdom amounts for average price received, average royalties paid, average production costs and netback are based on volumes sold and lifted. As at December 31, 2012, Antrim had no liftings.

The following table summarizes the Company's net production volumes during the financial year ended December 31, 2012 for each important field and in total, by product type.

Field	Light and Medium Crude Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)
Causeway	253	-	-	-
Tierra del Fuego	35	-	1,033	10
Total Production	288	-	1,033	10

SCHEDULE "B" – FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the Board of Directors of Antrim Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended December 31, 2012, and identifies the respective portions thereof that we have evaluated, audited and reviewed and reported on to the Company's management:

		Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
Preparation Date of Evaluation Report	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
March 26, 2013	United Kingdom	-	299,825	-	299,825

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after the preparation date.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

"signed by B. H. Emslie"

B. H. Emslie, P. Eng.

Calgary, Alberta
Date: March 26, 2013

SCHEDULE "C" – FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Antrim Energy Inc. (the "**Company**") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements.[1] This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012 using forecast prices and costs and constant prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this Report.

The Reserves Committee of the board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

"Stephen E. Greer"
Stephen E. Greer, Chief Executive Officer

"Terry Lederhouse"
Terry Lederhouse, Vice President, Commercial

"Jim Perry"
Jim Perry, Director

"Colin Maclean"
Colin Maclean, Director

March 26, 2013

[1] **Appendix 1 to Companion Policy 51-101CP sets out the meanings of certain terms that are used in sections 1 and 2 of this Report or in NI 51-101 or the Companion Policy.**

SCHEDULE "D"

ANTRIM ENERGY INC.

AUDIT COMMITTEE CHARTER
(February 23, 2011)

Purpose

1. The Audit Committee will assist the Board in meeting its responsibilities and will provide oversight concerning:

1.1 the preparation and disclosure of the consolidated financial statements, Management's Discussion and Analysis and annual and interim earnings press releases prior to release of the Company;

1.2 the credibility, integrity objectivity and adequacy of review procedures of financial reporting and public disclosure of financial information;

1.3 the Independent Auditor's qualifications, independence and performance;

1.4 the compliance by the Company with legal and regulatory reporting requirements.

2. The Committee will also prepare any report required by the rules of the Commission to be included in any proxy statement prepared by the Company or in the annual directors' report to shareholders.

Membership and Meetings

Membership

1. The Committee will be comprised of no fewer than three members as appointed by the Board of Directors all of which, in the opinion of the Board, are unrelated Directors.

2. Each Committee member will meet the independence, financial literacy and other membership requirements of the Toronto Stock Exchange and the rules and regulations of the AIM market of the London Stock Exchange and such other securities regulatory authorities having jurisdiction over the Company (the "Commissions").

3. At least one member of the Committee will have recent relevant experience of audit and financial matters.

Meetings

1. The Committee will meet in person or telephonically as often as it deems necessary, but not less frequently than four times per year.

2. Meetings of the Committee should be attended by representatives of the Company's principal external auditors ("Independent Auditors"), the Chief Financial Officer, Legal Counsel and others as deemed appropriate by the Committee.

3. The Committee will meet with management in connection with the consideration and approval of the Company's interim unaudited consolidated financial statements and annual audited consolidated financial statements. The Independent Auditors will be engaged by the Company to conduct a business review of each of the Company's interim unaudited consolidated financial statements. In connection with the Company's interim unaudited and annual audited consolidated financial statements, the Committee will meet privately with the Independent Auditor. In addition, the Committee may also meet privately from time to time with such other persons or groups as the Committee deems appropriate.

4. The Committee Chair will be responsible for calling the meetings of the Committee, establishing meeting agenda with input from management, supervising the conduct of the meetings and providing the Board with a timetable of significant financial statement milestones.

5. A majority of the number of appointed Committee members will constitute a quorum for conducting business at a meeting of the Committee.

Committee Authority and Responsibilities

Relationship with the Independent Auditors

1. The Committee will make recommendations to the Board with respect to the appointment or replacement of the Independent Auditor. In accordance with applicable laws, shareholders will be asked to ratify and approve the appointment of the Independent Auditor.

2. The Committee will approve and update the Board with regards to compensation and oversight of the work of the Independent Auditor for the purpose of preparing or issuing an audit report or related work.

3. The Independent Auditor will report directly to the Committee.

Pre-approval of Audit and Non-Audit Services

1. The Committee has the authority to pre-approve all auditing services and permitted non-audit services to be performed by the Independent Auditor for the Company and its subsidiaries.

Resources of the Committee

1. The Committee has the authority to retain independent legal, accounting or other advisors.

2. The Company will provide for funding, as and when deemed necessary or advisable by the Committee, for payment of compensation to the Independent Auditor and to any advisors employed by the Committee. Where the estimated fees for such services are in excess of $50,000, the unanimous consent of all Committee members is required prior to the engagement of such services.

3. Upon the request of the Committee, the Company will provide to each Committee member an induction and appropriate training for the role of an audit committee member.

Reports to the Board

1. The Committee will make available to the Board all Committee recommendations and Committee meeting minutes.

Charter Reviews

1. The Committee will review and reassess the adequacy of this Charter annually and recommend any proposed changes to the Board for approval.

Performance Assessment

1. The Corporate Governance Committee or the Committee will annually review the Audit Committee's own performance.

Whistle-blowing and Complaint Procedures

1. The Committee will oversee the Company's whistle-blowing policy as developed and approved by the Board.

2. The Committee will establish procedures for:

   2.1 The receipt, retention and treatment of complaints received by the company regarding accounting, internal accounting controls, or auditing matters;

   2.2 The confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters.

Financial Statement and Disclosure Matters

The Committee will:

1. Review and discuss with the Board, and the Independent Auditor as deemed necessary:

   1.1 The annual audited and quarterly unaudited consolidated financial statements of the Company, earnings press releases and disclosures made in Management's Discussion.

   1.2 Significant financial reporting issues, judgments, accruals, reserves or other estimates made in connection with the preparation of the Company's consolidated financial statements, including any significant changes in the Company's selection or application of accounting principles, any major issues relating to the adequacy of the Company's internal controls and any special steps adopted in light of material control deficiencies.

   1.3 The accounting treatment of unusual or non-recurring transactions.

   1.4 The effect of regulatory and accounting initiatives as well as off-balance sheet structures on the Company's financial statements.

2. Review and discuss with the Board reports from the Independent Auditors on:

   2.1 All critical accounting policies and practices to be used.

   2.2 All material alternative treatments of financial information within generally accepted accounting principles that have been discussed with management, the ramifications of each alternative and the treatment preferred by the Independent Auditor.

   2.3 Other material written communications between the Independent Auditor and management, such as any management letter or schedule of unadjusted differences.

3. Receive and review reports, and discuss with the Board, on the Company's disclosure controls and procedures and the adequacy of internal controls over financial reporting and public disclosure of financial information to provide reasonable assurance that they are sufficient to meet the requirements under National Instrument 52-109.

4. Discuss with management and the Board the Company's earnings press releases (including any use of "pro-forma" or "adjusted non-GAAP information"), financial information and earnings guidance provided to analysts and rating agencies.

5. Discuss with management and the Board the Company's major financial risk exposures and the policies and procedures management has taken to monitor and control such exposures.

6. Discuss with the Independent Auditor the conduct of the audit, including any difficulties encountered in the course of the audit, any restrictions on the scope of activities or access to requested information, and any disagreements with management.

Oversight of the Company's Relationship with the Independent Auditor

The Committee will:

1. At least annually, review a report from the Independent Auditor describing:

    1.1 the Independent Auditor's internal quality-control procedures;

    1.2 any material issues raised by the most recent internal quality-control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the firm;

    1.3 any steps taken to deal with any such issues, and

    1.4 all relationships between the Independent Auditor and the Company.

2. Evaluate the qualifications, performance and independence of the Independent Auditor and the lead audit partner.

3. Consider whether the auditor's quality controls are adequate and the provision of permitted non-audit services is compatible with maintaining the auditor's independence and produce an annual report explaining how these controls provide adequate protection of auditor independence.

4. Ensure the rotation of the lead (or coordinating) audit partner having primary responsibility for the audit and the audit partner responsible for reviewing the audit as required by law. Consider whether, in order to assure continuing auditor independence, it is appropriate to adopt a policy of rotating the independent auditing firm on a regular basis.

5. Review and approve hiring policies related to current and former staff of the present and former Independent Auditor.

6. Meet with the Independent Auditor prior to the audit to discuss the planning and staffing of the audit.

Limitation of Audit Committee's Role

1. While the Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Committee to plan or conduct audits or to determine that the Company's consolidated financial statements

and disclosures are complete and accurate and are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management and the Independent Auditor.

Annual General Meeting of Shareholders

1. The Committee Chair will be present at the annual general meeting of shareholders of the Company to answer any questions relating to the audit function.

Public Disclosure

1. This Charter will be disclosed in the Company’s Annual Information Form, included on the Company’s web-site and will be made available upon request sent to the Company’s Corporate Secretary. The Company’s annual report to shareholders will state that this Charter is available on the Company’s web-site and will be available upon request to the Company’s Corporate Secretary.