UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 20-F

(Mark One)

[ ] REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR (g) OF THE SECURITIES EXCHANGE ACT OF 1934

OR

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended: **DECEMBER 31, 2011**

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

OR

[ ] SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from n/a to n/a

Commission file number **333-121620**

HARVEST OPERATIONS CORP.

(Exact name of Registrant as specified in its charter)

HARVEST OPERATIONS CORP.
(Translation of Registrant's name into English)

ALBERTA, CANADA
(Jurisdiction of incorporation or organization)

2100, 330 - 5th Ave. SW Calgary, Alberta, Canada T2P 0L4
(Address of principal executive offices)

Mr. Myunghuhn Yi, President & CEO
2100, 330 - 5th Ave. SW Calgary, Alberta, Canada T2P 0L4
myunghuhn.yi@harvestenergy.ca

403-268-3189
(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

Securities registered or to be registered pursuant to Section 12(b) of the Act.
(none)

Securities registered or to be registered pursuant to Section 12(g) of the Act.
(none)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.
(none)

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

Common shares as of December 31, 2011: 386,078,649

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
[ ] Yes [X] No

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.
[X] Yes [ ] No

Note – Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.*
[ ] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). *
[ ] Yes [ ] No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

[ ] Large accelerated filer [ ] Accelerated filer [X] Non-accelerated filer

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

[ ] U.S. GAAP
[X] International Financial Reporting Standards as issued by the International Accounting Standards Board
[ ] Other

If "Other" has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.
[ ] Item 17 [ ] Item 18

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
[ ] Yes [X] No

***Harvest Operations Corp. is a "voluntary filer" and submits this Form 20-F pursuant to its obligation under its indenture relating to its 67/8% senior notes due October 2017.**

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GLOSSARY OF TERMS

In this annual report, the following terms shall have the meanings set forth below, unless otherwise indicated.

Certain other terms used herein but not defined herein are defined in NI 51-101 and SEC regulations and, unless the context otherwise requires, shall have the same meanings herein as in SEC regulations.

"6.40% Debentures Due 2012" means the 6.40% convertible unsecured subordinated debentures of the Corporation due October 31, 2012, which were assumed by the Corporation from VERT on February 3, 2006 pursuant to the plan of arrangement under the ABCA by which the Corporation merged with VERT.

"7.25% Debentures Due 2013" means the 7.25% convertible unsecured subordinated debentures of the Corporation due September 30, 2013.

"7.25% Debentures Due 2014" means the 7.25% convertible unsecured subordinated debentures of the Corporation due February 28, 2014.

"7.50% Debentures Due 2015" means the 7.50% convertible unsecured subordinated debentures of the Corporation due May 31, 2015.

"67/8% Senior Notes" means the Corporation's 67/8% Senior Notes due 2017.

"77/8% Senior Notes" means the Corporation's 77/8% Senior Notes due 2011.

"ABCA" means the *Business Corporations Act* (Alberta), together with any or all regulations promulgated thereunder, as amended from time to time.

"BlackGold" means the BlackGold oil sands project acquired by the Corporation from KNOC on August 6, 2010, more fully described in Note 26 of the Corporation's audited consolidated financial statements for the year ended December 31, 2011 included in this annual report.

"Breeze Trust No. 1" means Harvest Breeze Trust No. 1, a trust established under the laws of the Province of Alberta, wholly owned by the Corporation.

"Breeze Trust No. 2" means Harvest Breeze Trust No. 2, a trust established under the laws of the Province of Alberta, wholly owned by the Corporation.

"Canadian GAAP" means accounting principles generally accepted in Canada.

"COGE Handbook" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum.

"Corporation" means Harvest Operations Corp.

"Credit Facility" means the $800 million revolving credit facility, as amended, provided by a syndicate of lenders to Harvest Operations as more fully described in Note 10 of the Corporation's audited consolidated financial statements for the year ended December 31, 2011 included in this annual report.

"Debentures" means, collectively, the 6.40% Debentures Due 2012, the 7.25% Debentures Due 2013, the 7.25% Debentures Due 2014 and the 7.50% Debentures Due 2015.

"Debenture Indenture" means (i) the trust indenture dated January 29, 2004 among Harvest Operations and Valiant Trust Company, as trustee, providing for the issue of debentures, as supplemented by the third supplemental indenture dated November 22, 2006 in respect of the 7.25% Debentures Due 2013, in respect of the fourth supplemental indenture dated February 1, 2007 in respect of the 7.25% Debentures Due 2014 and in respect of the fifth supplemental indenture dated April 25, 2008 in respect of the 7.50% Debentures Due 2015 and (ii) the trust indenture dated January 15, 2003 between VERT and Computershare Trust Company of Canada as trustee, providing for the issue of debentures, as supplemented by the first supplemental indenture dated October 20, 2005 in respect of the 6.40% Debentures Due 2012.

“Downstream” means the Corporation’s petroleum refining and marketing segment operating under the North Atlantic trade name, comprised of a medium gravity sour crude hydrocracking refinery with a 115,000 bbls/d nameplate capacity and a marketing division with 55 gasoline outlets, 3 commercial cardlock locations, a retail heating fuels business and a commercial and wholesale petroleum products business, all located in the Province of Newfoundland and Labrador.

“EPC” means engineering, procurement and construction.

“Farmout” means an agreement whereby a third party agrees to pay for all or a portion of the drilling of a well on one or more of the Properties in order to earn an interest therein, with an Operating Subsidiary retaining a residual interest in such Properties.

“Future Net Revenue” means the estimated net amount to be received with respect to the development and production of reserves computed by deducting, from estimated future revenues, estimated future royalty obligations, costs related to the development and production of reserves and abandonment and reclamation costs (corporate general and administrative expenses and financing costs are not deducted).

“GLJ” means GLJ Petroleum Consultants Ltd., independent oil and natural gas reserves evaluators of Calgary, Alberta.

“Gross” means:

(a) in relation to Harvest and the Operating Subsidiaries' interest in production and reserves, its "Corporation gross reserves", which are Harvest and the Operating Subsidiaries' interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of Harvest and the Operating Subsidiaries;

(b) in relation to wells, the total number of wells in which Harvest and the Operating Subsidiaries have an interest; and

(c) in relation to properties, the total area of properties in which Harvest and the Operating Subsidiaries have an interest.

“Harvest Board” means the board of directors of Harvest Operations.

“Harvest” and **“Harvest Operations”** means Harvest Operations Corp., a corporation amalgamated under the laws of the Province of Alberta.

“Independent Reserves Evaluators” means McDaniel and GLJ, who evaluated the crude oil, natural gas liquids and natural gas reserves of Harvest and the Operating Subsidiaries as at December 31, 2011, in accordance with the standards contained in the COGE Handbook and the reserve definitions and other requirements contained in NI 51-101 and Rule 4–10 of Regulation S–X.

“IFRS” means International Financial Reporting Standards as issued by the International Accounting Standards Board (“IASB”).

“KNOC” means Korea National Oil Corporation.

"KNOC Acquisition" means the purchase by KNOC Canada of all of the issued and outstanding Trust Units of the Trust for total consideration of approximately $1.8 billion and the assumption of approximately $2.3 billion of debt.

"KNOC Arrangement" means the plan of arrangement for the KNOC Acquisition implemented pursuant to Section 193 of the ABCA involving, among others, the Trust, Harvest Operations, KNOC Canada, KNOC and the holders of Trust Units, which became effective on December 22, 2009.

"KNOC Canada" means KNOC Canada Ltd., a corporation incorporated under the laws of the Province of Alberta.

"McDaniel" means McDaniel & Associates Consultants Ltd., independent oil and natural gas reserves evaluators of Calgary, Alberta.

"Net" means:

(a) in relation to Harvest and the Operating Subsidiaries' interest in production and reserves, Harvest and the Operating Subsidiaries' interest (operating and non-operating) share after deduction of royalties obligations, plus Harvest and the Operating Subsidiaries' royalty interest in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating Harvest and the Operating Subsidiaries' working interest in each of its gross wells; and

(c) in relation to Harvest and the Operating Subsidiaries' interest in a property, the total area in which Harvest and the Operating Subsidiaries have an interest multiplied by the working interest owned by Harvest and the Operating Subsidiaries.

"NI 51-101" means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities.

"North Atlantic" means North Atlantic Refining Limited, a private company, and all wholly owned subsidiaries of North Atlantic Refining Limited.

"Note Indenture" means the trust indenture made as of October 4, 2010 between U.S. Bank National Association as trustee thereunder and Harvest Operations, providing for the issuance of the 67/8% Senior Notes.

"NYSE" means the New York Stock Exchange.

"Operating Subsidiaries" means Redearth Partnership (prior to September 30, 2010), Breeze Resource Partnership, Breeze Trust No. 1, Breeze Trust No. 2, and Hay River Partnership, each (other than Redearth Partnership with respect to which the Corporation held a 60% interest prior to its dissolution) a direct or indirect wholly-owned subsidiary of the Corporation, and "Operating Subsidiary" means any of them.

"**Person**" includes an individual, a body corporate, a trust, a union, a pension fund, a government and a governmental agency.

"**Production**" means, with respect to the Upstream operations the produced petroleum, natural gas and natural gas liquids attributed to the Properties and with respect to the Downstream operations, the production of refined petroleum products at the Refinery.

“**Properties**” means the working, royalty or other interests of Harvest and the Operating Subsidiaries in any petroleum and natural gas rights, tangibles and miscellaneous interests, including properties which may be acquired by Harvest and the Operating Subsidiaries from time to time.

“**Purchase and Sale Agreement**” means the purchase and sale agreement dated August 22, 2006 between the Corporation and Vitol Refining Group B.V. providing for the purchase of the outstanding shares of North Atlantic and the entering into of the Supply and Offtake Agreement.

“Redearth Partnership” means the general partnership formed on August 23, 2002 under the laws of the Province of Alberta. In September 2010 Harvest acquired 100% ownership interest, thereafter, Redearth Partnership was dissolved and Harvest Operations became the owner of all the assets and assumed all of the liabilities of the Redearth Partnership.

“Refinery” means the 115,000 barrel per day medium gravity sour crude hydrocracking refinery located in the Province of Newfoundland and Labrador, owned by North Atlantic.

“Reserves Report” means, collectively, the reports prepared by the Independent Reserve Evaluators evaluating the crude oil, natural gas liquids and natural gas reserves of Harvest and the Operating Subsidiaries as at December 31, 2011, in accordance with the standards contained in the COGE Handbook and the reserve definitions and other requirements contained in NI 51-101 and SEC regulations.

“SEC” means the United States Securities and Exchange Commission.

“Supply and Offtake Agreement” or **“SOA”** means the supply and offtake agreement dated October 19, 2006 and as amended October 12, 2009 entered into between North Atlantic and Vitol Refining, S.A. (“Vitol”).

“Supply and Offtake Agreement (2011)” or **“SOA (2011)”** means the supply and offtake agreement dated October 11, 2011 and as amended December 19, 2011 entered into between North Atlantic and Macquarie Energy Canada Ltd. (“MEC”) the terms of which are summarized under Item 10.C "Material Contracts".

“Trust” means Harvest Energy Trust.

“Trust Indenture” means the fifth amended and restated trust indenture dated May 20, 2008 between the Trustee and Harvest Operations, as amended on December 22, 2009 pursuant to the KNOC Arrangement.

“Trust Unit” means a trust unit of the Trust and unless the context otherwise requires means ordinary Trust Units of the Trust.

“Trustee” means 1496965 Alberta Ltd in its capacity as trustee of the Trust.

“TSX” means the Toronto Stock Exchange.

“Upstream” means Harvest’s petroleum and natural gas segment, consisting of the exploitation, production and subsequent sale of petroleum, natural gas and natural gas liquids in Alberta, Saskatchewan and British Columbia.

“U.S. GAAP” means accounting principles generally accepted in the United States.

"VERT" means Viking Energy Royalty Trust, a trust established under the laws of the Province of Alberta, wholly owned by the Trust.

"Viking" means Viking Holdings Inc., a corporation incorporated under the laws of the Province of Alberta that formerly acted as administrator of VERT, which amalgamated with Harvest Operations on July 1, 2006.

"Working Interest" means an undivided interest held by a party in an oil and/or natural gas or mineral lease granted by a Crown or freehold mineral owner, which interest gives the holder the right to "work" the property (lease) to explore for, develop, produce and market the lease substances but does not include, among other things, a royalty, overriding royalty, gross overriding royalty, net profits interest or other interest that entitles the holder thereof to a share of production or proceeds of sale of production without a corresponding right or obligation to "work" the property.

ABBREVIATIONS AND CONVERSIONS

In this annual report, the following abbreviations have the meanings set forth below:

/d	Per day
3-D	Three dimensional
AECO	AECO "C" hub price index for Alberta natural gas
^{o}API	The measure of the density or gravity of liquid petroleum products
boe	Barrel of oil equivalent, using the conversion factor of 6 mcf of natural gas being equivalent to one bbl of oil, unless otherwise specified. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
bbl	Barrel
bbls	Barrels
EOR	Enhanced oil recovery
GJ	Gigajoule
H2S	Hydrogen sulfide gas
Mbbls	Thousand barrels
Mboe	Thousand barrels of oil equivalent
mcf	Thousand cubic feet
MMboe	Million barrels of oil equivalent
MMcf	Million cubic feet
NGLs	Natural gas liquids
SAGD	Steam-assisted gravity drainage is an enhanced oil recovery technology for producing heavy crude oil and bitumen
WTI	West Texas Intermediate, the reference price in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
$000	Thousands of dollars
$millions	Millions of dollars

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units):

To Convert From	To	Multiply By
mcf	cubic metres	28.174

cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this annual report and documents incorporated by reference herein, constitute forward-looking statements. These statements relate to future events and future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are subject to certain risks and uncertainties that could cause actual results to differ materially from those included in the forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as: “budget”, “outlook”, “forecast”, "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. Harvest believes the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this annual report should not be unduly relied upon. These statements speak only as of the date of this annual report or as of the date specified in the documents incorporated by reference into this annual report, as the case may be.

In particular, this annual report, and the documents incorporated by reference herein, contains forward-looking statements pertaining to:

- the operation of our facilities;
- expected operational and financial performance in future periods;
- expected increases in revenue, net income and cash flows attributable to development and production activities;
- estimated capital expenditures;
- competitive advantages and ability to compete successfully;
- intention to continue adding value through drilling and exploitation activities, and capital projects;
- emphasis on having a low cost structure;
- intention to retain a portion of cash flows to repay indebtedness and invest in further development of Harvest’s properties;
- reserve estimates and estimates of the present value of Harvest’s future net cash flows;
- methods of raising capital for exploitation and development of reserves and other capital projects;
- future sources of funding, debt levels and availability of committed credit facilities;
- factors upon which to decide whether or not to undertake a capital project;
- plans to make acquisitions and expected synergies from acquisitions made;
- possible commerciality of exploration and development projects;
- expectations regarding the development and production potential of petroleum and natural gas properties;
- expected timing cost and associated impact of facility turnaround and maintenance;
- treatment under government regulatory regimes including without limitation, environmental and tax regulation;
- ultimate recoverability of the Corporation’s assets;
- overall demand for gasoline, low sulphur diesel, jet fuel, furnace oil and other refined products; and

- the level of global production of crude oil feedstocks and refined products.

With respect to forward-looking statements contained in this annual report and the documents incorporate by reference herein, Harvest has made assumptions regarding, among other things:

- future oil and natural gas prices and differentials between light, medium and heavy oil prices;
- future interest rates, foreign exchange rates and royalty rates;
- the ability to maintain Harvest's operations;
- the cost of expanding Harvest's property holdings;
- the ability to obtain equipment in a timely manner to carry out development activities;
- the ability to market oil and natural gas successfully to current and new customers;
- the impact of increasing competition;
- the ability to obtain financing on acceptable terms;
- the ability to add production and reserves through development and exploitation activities; and
- the ability to produce gasoline, low sulphur diesel, jet fuel, furnace oil, and other refined products that meet customer specifications.

Some of the risks that could affect Harvest's future results and could cause results to differ materially from those expressed in forward-looking statements include:

- global supply and demand for crude oil and natural gas;
- the volatility of oil and natural gas prices, including the differential between the price of light, medium and heavy oil;
- the uncertainty of estimates of petroleum and natural gas reserves;
- the impact of competition;
- the impact of technology on operations and developments of Harvest's assets;
- difficulties encountered in the integration of acquisitions;
- difficulties encountered during the drilling for and production of oil and natural gas;
- difficulties encountered in delivering oil and natural gas to commercial markets;
- foreign currency fluctuations;
- the uncertainty of Harvest's ability to attract capital;
- changes in, or the introduction of new, government laws and regulations relating to the oil and natural gas business including without limitation, tax, royalty and environmental law and regulation;
- costs associated with developing and producing oil and natural gas;
- compliance with environmental and tax regulations;
- liabilities stemming from accidental damage to the environment;
- loss of the services of any of Harvest's senior management or directors;
- adverse changes in the economy generally;
- labour and material shortages;
- the volatility of refining gross margins including the price of feedstocks as well as the prices for refined products; and
- the stability of the Refinery throughput performance.

Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this annual report and the documents incorporated by reference herein are expressly qualified by this cautionary statement. Except as required by law, Harvest Operations does not undertake any obligation to publicly update or revise any forward-looking statements and readers should also carefully consider the matters discussed under “Item 3.D Risk Factors".

NON-GAAP MEASURES

Harvest uses certain financial reporting measures that are commonly used as benchmarks within the petroleum and natural gas industry hereinafter referred to as “non-GAAP” such as: “cash contribution", “operating netbacks”, “operating netback prior to/after hedging”, “operating income (loss)”, “gross margin (loss)”, “total debt”, “total financial debt”, “total capitalization”, “EBITDA”, “secured debt to annualized EBITDA”, “total debt to annualized EBITDA”, “secured debt to total capitalization”, “total debt to total capitalization” and “interest coverage ratio”.

“Operating netbacks” are reported on a per boe basis and used extensively in the Canadian energy sector for comparative purposes. “Operating netbacks” include revenues, operating expenses, transportation and marketing expenses, and realized gains or losses on risk management contracts. “Gross margin (loss)” is commonly used in the refining industry to reflect the net funds received from the sale of refined products after considering the cost to purchase the feedstock and is calculated by deducting purchased products for resale and processing from total revenue. “Operating income (loss)” is commonly used for comparative purposes in the petroleum and natural gas and refining industries to reflect operating results before items not directly related to operations. “Total debt”, “total financial debt”, “total capitalization”, and “EBITDA” are used to assist management in assessing liquidity and the Corporation’s ability to meet financial obligations. “Secured debt to annualized EBITDA”, “total debt to annualized EBITDA”, “secured debt to total capitalization”, “total debt to total capitalization” and “interest coverage ratio” are terms defined in Harvest’s Credit Facility and Note Indenture for the purpose of calculation of Harvest’s financial covenants. The non-GAAP measures do not have any standardized meaning prescribed by GAAP or IFRS and may not be comparable to similar measures used by other issuers. The determination of the non-GAAP measures have been illustrated throughout this annual report, with reconciliations to IFRS measures and/or account balances, except for EBITDA which is shown below.

Reconciliation of EBITDA

EBITDA is defined in Harvest’s Credit Facility as earnings before finance costs, income tax expense or recovery, depletion, depreciation and amortization “DD&A”, exploration and evaluation costs, impairment of assets, unrealized gains or losses on risk management contracts, unrealized gains or losses on foreign exchange, gains or losses on disposition of assets and other non-cash items. The following is a reconciliation of EBITDA to net loss, the nearest IFRS measure:

	Year Ended December 31	
($000’s)	**2011**	2010
Net loss	**(104,657)**	(81,163)
DD&A	**626,698**	553,732
Unrealized gains on risk management contracts	**(746)**	(2,358)
Unrealized (gains) losses on foreign exchange	**2,555**	(1,875)
Unsuccessful exploration and evaluation costs	**17,757**	2,858
Impairment of PP&E	-	13,661
Gains on disposition of PP&E	**(7,883)**	(741)
Income tax recovery	**(29,827)**	(65,309)
Finance costs	**109,127**	100,808
Other non-cash items	**4,795**	(1,093)
EBITDA[1]	**617,819**	518,520

(1) As stipulated by the Credit Facility, annualized EBITDA is a twelve month rolling EBITDA which also includes net income impact from acquisition or disposition as if the transaction had been effected at the

beginning of the period. As such, 2011 annualized EBITDA is $5.0 million (2010 – $9.8 million) higher than EBITDA.

PREDECESSOR PRESENTATION

On December 22, 2009, KNOC Canada purchased all of the issued and outstanding Trust Units of Harvest Energy Trust. The acquisition of all the issued and outstanding Trust Units of the Trust resulted in a change of control in which KNOC Canada became the sole unit holder of the Trust. On May 1, 2010, an internal reorganization was completed pursuant to which the Trust was dissolved and the Trust's wholly owned subsidiary and the manager of the Trust, Harvest Operations Corp., was amalgamated into KNOC Canada to continue as one corporation under the name Harvest Operations Corp. The carrying values of Harvest's assets and liabilities were determined from the existing carrying values of KNOC Canada's assets and liabilities and therefore reflect the fair values established through the purchase.

The Trust meets the definition of a predecessor as described in Exchange Act Rule 12b-2 and Securities Act Rule 405; therefore, certain historical financial information related to the Trust is included in this annual report. Accordingly, the financial information presented in this annual report for the year ended and as at December 31, 2011 and 2010 is that of Harvest Operations Corp. (the successor company) while any comparative periods represent the financial information of Harvest Energy Trust (the predecessor company). As at December 31, 2009 the internal reorganization had not yet taken place; therefore, both Harvest Energy Trust and KNOC Canada existed at this date. However, KNOC Canada was incorporated on October 9, 2009 and did not have any results of operations or cash flows between October 9, 2009 and December 31, 2009, aside from capital contributions from KNOC to finance the KNOC Acquisition and cash used in the KNOC Acquisition; as such, the financial information presented for the year ended and as at December 31, 2009 is that of the Trust, unless otherwise stated, as this provides more relevant information in comparing the results of operations.

ITEM 1. IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISERS

Not applicable.

ITEM 2. OFFER STATISTICS AND EXPECTED TIMETABLE

Not applicable.

ITEM 3. KEY INFORMATION

A. Selected Financial Information

The financial data presented below for Harvest Operations' and Harvest Energy Trust's is from the audited consolidated financial statements. The consolidated financial statements of Harvest Operations for 2011 and 2010 have been prepared in accordance with IFRS, as issued by IASB. The December 31, 2010 consolidated financial statements were initially prepared in accordance with Canadian GAAP, consistent with the prior years and the periods ended December 31, 2009, 2008 and 2007. The consolidated financial information as at and for the year ended December 31, 2010 have been adjusted in accordance with IFRS 1 "First-time Adoption of International Financial Reporting Standards", and therefore the financial information set forth in this annual report on Form 20-F for the year ended December 31, 2010 may differ from information previously published. Harvest adopted IFRS with a transition date of January 1, 2010. For details regarding the adjustments made with respect to the comparative data refer to Note 27 to the annual audited consolidated financial statements contained in this annual report. The selected historical consolidated financial information presented below is condensed and may not contain all of the information that readers should consider. This selected financial data should be read in conjunction with the annual audited consolidated financial statements, the notes thereto and the section entitled “Item 5 Operating and Financial Review and Prospects”. The amounts presented below for the years 2009, 2008, and 2007 reflect the adjustments made to conform with U.S. GAAP.

In accordance with IFRS

($000's, except for per share amounts)		**2011**		**2010**
Income statement data				
Net revenues				
Upstream	$	1,091,414	$	852,247
Downstream		3,239,455		3,105,957
Total	$	4,330,869	$	3,958,204
Operating loss	$	(36,089)	$	(49,613)
Net loss	$	(104,657)	$	(81,163)
Net loss per common share				
Basic	$	(0.28)	$	(0.27)
Diluted	$	(0.28)	$	(0.27)
Distributions/dividends declared	$	-	$	-
Distributions/dividends declared - U.S. dollars[1]	$	-	$	-
Distributions declared, per common share	$	-	$	-
Balance sheet data				
Total assets	$	6,284,370	$	5,388,740
Net assets	$	3,453,644	$	3,016,855
Shareholder’s capital	$	3,860,786	$	3,355,350
Temporary equity	$	-	$	-
Capital expenditures				
Upstream	$	1,246,148	$	953,674
Downstream		284,244		71,234
Total	$	1,530,392	$	1,024,908
Share data				
Weighted average common shares outstanding				
Basic and diluted		377,908,587		303,005,645

[1] Translated using the average noon buying rate as disclosed in “Exchange Rate Information” under Item 3.A below

In accordance with US GAAP

($000's, except for per Trust Unit amounts)		**2009**		**2008**		**2007**
Income statement data						
Net revenues						
Upstream	$	757,448	$	1,294,769	$	971,044
Downstream		2,381,637		4,194,595		3,098,556
Total	$	3,139,085	$	5,489,364	$	4,069,600
Operating income (loss)	$	(603,762)	$	550,681	$	339,430
Net income (loss)	$	(641,906)	$	(1,343,337)	$	159,194
Net income (loss) per Trust Unit						
Basic	$	(3.69)	$	(8.79)	$	1.15

Diluted	$ (3.69)	$ (8.79)	$ 1.14
Distributions/dividends declared	$ 164,770	$ 551,325	$ 610,280
Distributions/dividends declared - U.S. dollars[(1)]	$ 144,289	$ 517,197	$ 567,805
Distributions declared, per Trust Unit	$ 1.00	$ 3.60	$ 4.40
Balance sheet data			
Total assets	$ 2,476,415	$ 3,561,515	$ 4,953,634
Net assets	$ (2,073,824)	$ (997,695)	$ (976,476)
Shareholder's capital	$ -	$ -	$ -
Temporary equity	$ 2,422,133	$ 1,562,806	$ 2,997,136
Capital expenditures			
Upstream	$ 124,160	$ 400,085	$ 438,830
Downstream	43,875	56,162	44,111
Total	$ 168,035	$ 456,247	$ 482,941
Share data			
Weighted average Trust Units outstanding			
Basic	173,785,806	152,836,717	138,440,869
Diluted	173,785,806	152,836,717	139,088,543

(1) Translated using the average noon buying rate as disclosed in "Exchange Rate Information" under Item 3.A below

EXCHANGE RATE INFORMATION

All dollar amounts set forth in this annual report are expressed in Canadian dollars, except where otherwise indicated. References to Canadian dollars, Cdn$, C$ or $ are to the currency of Canada and references to U.S. dollars or US$ are to the currency of the United States.

The exchange rate information presented below is based on the Bank of Canada noon rates. Such rates are set forth as U.S. dollars per $1.00.

The exchange rate between the Canadian dollar and the U.S. dollar on April 27, 2012 was US$1.0197.

The high and low exchange rates between the Canadian dollar and the U.S. dollar for each month during the previous six months are as follows:

	High	Low
March 2012	1.0153	0.9985
February 2012	1.0136	0.9984
January 2012	1.0014	0.9735
December 2011	0.9896	0.9610
November 2011	0.9876	0.9536
October 2011	1.0065	0.9430

The average exchange rates between the Canadian dollar and the U.S. dollar for the five most recent financial years are as follows:

	Average

2011	1.0110
2010	0.9709
2009	0.8757
2008	0.9381
2007	0.9304

B. Capitalization and Indebtedness

Not applicable.

C. Reasons for the Offer and Use of Proceeds

Not applicable.

D. Risk Factors

Both the Upstream and Downstream operations are conducted in the same business environment as most other operators in the respective businesses. The risk factors set forth below have been separated into those applicable to Upstream operators, those applicable to Downstream operators and those applicable to Harvest's structure.

RISKS RELATED TO THE UPSTREAM OPERATIONS

Prices received for petroleum and natural gas have fluctuated widely in recent years and are also impacted by volatility in the Canadian/U.S. currency exchange ratio.
Cash flow from the Upstream operations is dependent on the prices received from the sale of petroleum and natural gas production. Prices for petroleum, natural gas and natural gas liquids have fluctuated widely during recent years and are determined by supply and demand factors beyond the Corporation's control, including weather, general economic conditions, conditions in other petroleum producing regions, market uncertainty, the availability of alternative fuel sources, actions of the Organization of Petroleum Exporting Countries ("OPEC"), the price of foreign imports of petroleum and natural gas, concern over climate changes or greenhouse gas ("GHG") emissions and government regulations. Oil prices received from production in Canada also reflect changes in the Canadian/U.S. currency exchange rate. A decline in petroleum and/or natural gas prices or an increase in the Canadian/U.S. currency exchange rate could have a material adverse effect on the Corporation's cash from operating activities and financial condition as well as funds available for the development of its petroleum and natural gas reserves.

Any prolonged period of low petroleum and natural gas prices could result in a material reduction of Harvest's operating and financial results, production revenue, reserves and overall value and may lead to a decision by the Corporation to suspend or reduce production. Any such suspension or reduction of production would result in a corresponding substantial decrease in revenues and earnings and could materially impact Harvest's ability to meet its debt servicing obligations and could expose the Corporation to significant additional expense as a result of any future long-term contracts. If production was not suspended or reduced during such period, the sale of the petroleum and natural gas products produced by Harvest at such reduced prices would lower its revenues.

Harvest conducts an assessment of the carrying value of its assets to the extent required by IFRS. If petroleum and/or natural gas prices decline, the carrying value of Harvest's assets could be subject to downward revision and the Corporation's earnings could be adversely affected. The substantial volatility in petroleum and natural gas prices over recent years has affected the profitability of the oil and gas industry and Harvest. Although Harvest did not incur any impairment charges to the petroleum and natural gas assets in 2011, there can be no assurance that further declines in petroleum and natural gas prices or other circumstances will not result in such impairment charges at some future dates.

The differential between light oil and heavy oil compounds the fluctuations in benchmark oil prices.
At the end of 2011, Harvest's production was approximately 43% light and medium gravity crude oil, 16% heavy oil, 9% NGLs and 32% natural gas. Processing and refining heavy oil is more expensive than processing and refining light oil and accordingly, producers of heavy oil receive lower prices for their production. The differential between light oil and heavy oil has fluctuated widely during recent years and when compounded with the fluctuations in the benchmark prices for light oil, the result is a substantial increase in the volatility of heavy oil prices. An increase in the heavy oil differential usually results in Harvest receiving lower prices for heavy oil and could have a material adverse effect on the Corporation's cash from operating activities and financial condition as well as funds available for the development of the Corporation's petroleum and natural gas reserves. The heavy oil price differential is normally the result of the seasonal supply and demand for heavy oil, pipeline constraints and heavy oil processing capacity of refineries, all of which are beyond Harvest's control.

The operation of petroleum and natural gas properties involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected and/or dangerous conditions against which Harvest may not be insured or that may result in damages in excess of existing insurance coverage.
The operation of petroleum and natural gas wells involves a number of operating and natural hazards which may result in blowouts, explosions, fire, gaseous leaks, migration of harmful substances, spills, environmental damage and other unexpected and/or dangerous conditions resulting in damage to Harvest's assets and potentially assets of third parties. In addition, all of Harvest's operations are subject to all of the risks normally incident to the transportation, processing and storing of petroleum, natural gas and other related products, drilling and completion of petroleum and natural gas wells, and the operation and development of petroleum and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoir pressure or productivity, blowouts, equipment failures and other accidents, sour gas releases, uncontrollable flows of petroleum, natural gas or well fluids, adverse weather conditions, pollution and other environmental risks. Harvest's corporate EH&S manual has a number of specific policies to minimize the risk of environmental contamination, including emergency response should an incident occur. If areas of higher risk are identified, Harvest will undertake to analyze and recommend changes to reduce the risk including replacement of specific infrastructure. Harvest employs prudent risk management practices and maintains liability insurance in amounts consistent with industry standards. In addition, business interruption insurance has been purchased for selected facilities. The Corporation may become liable for damages arising from such events against which it cannot insure, which it may elect not to insure or that may result in damages in excess of existing insurance coverage. Costs incurred to repair such damage or pay such liabilities would reduce Harvest's cash flow. The occurrence of a significant event against which the Corporation is not fully insured could have a material adverse effect on Harvest's financial position.

The operation of petroleum and natural gas properties requires access to people and equipment on a regular basis, which could be affected by factors beyond the Corporation's control.
Access for people and equipment may be restricted due to weather, accidents, natural disasters, government regulations or third party actions. Because of these factors, Harvest may be unable to develop or produce from its petroleum or natural gas properties.

If the third party operators of Harvest's joint venture properties fail to perform their duties properly, production may be reduced and proceeds from the sale of production may be negatively impacted.
Continuing production from a property and to a certain extent, the marketing of production there from, are largely dependent upon the capabilities of the operator of the property. To the extent the operator fails to perform its duties properly, production may be reduced and proceeds from the sale of production from properties operated by third parties may be negatively impacted. Although Harvest maintains operative control over the majority of its properties, there is no guarantee that the Corporation will remain the operator of such properties or that the Corporation will operate other properties that may be acquired.

Harvest is subject to risks related to deregulation of electrical power systems and the volatility of electrical power prices.

A portion of Harvest's operating expenses are electrical power costs. As a result of the deregulation of the electrical power system in Alberta, electrical power prices have been set by the market based on supply and demand and recently, electrical power prices in Alberta have been volatile. To mitigate the Corporation's exposure to the volatility in electrical power prices, it may enter into fixed priced forward purchase contracts for a portion of the Corporation's electrical power consumption in Alberta. In respect of the operations in Saskatchewan, the Saskatchewan power system is regulated and as such, electrical power costs are not subject to significant volatility. However, there can be no certainty that the Saskatchewan power system will not deregulate in the future.

Defects in title may defeat Harvest's claims to certain properties.

Although title reviews will generally be conducted on the properties in accordance with industry standards, such reviews do not guarantee or certify that a defect in title may not arise to defeat Harvest's claim to certain properties. If such were the case, Harvest's entitlement to the production and reserves associated with such properties could be jeopardized, which could have a material adverse effect on the Corporation's financial condition and results of operations.

The markets for petroleum and natural gas depend upon available capacity to refine crude oil and process natural gas, pipeline capacity to transport the products to customers, and other factors beyond the Corporation's control.

Harvest's ability to market petroleum and natural gas from its wells depends upon numerous factors beyond the Corporation's control, including:

- the availability of capacity to refine heavy oil;
- the availability of natural gas processing capacity;
- the availability of pipeline capacity;
- the availability of diluents to blend with heavy oil to enable pipeline transportation;
- the price of oilfield services;
- the accessibility of remote areas to drill and subsequently service wells and facilities; and
- the effects of inclement weather.

Because of these factors, Harvest may be unable to market all of the petroleum or natural gas it is capable of producing or to obtain favorable prices for the petroleum and natural gas it produces.

The reservoir and recovery information in reserves reports are estimates and actual production and recovery rates may vary from the estimates and the variations may be significant.

The reserves and recovery information contained in the Reserves Report prepared by the Independent Reserves Evaluators are complex estimates and the actual production and ultimate reserves recovered from the Corporation's properties may differ from the estimates prepared by the independent reserves evaluators. There are numerous uncertainties inherent in estimating quantities of petroleum and natural gas reserves, including many factors beyond the Corporation's control. The reserves data in this annual report represents estimates only. In general, petroleum and natural gas reserves and the future net cash flows are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties and the assumed effects of regulation by governmental agencies (including regulations related to royalty payments), all of which may vary considerably from actual results. All such estimates are to some degree uncertain, and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable petroleum and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected there from, prepared by different evaluators or by the same evaluators at different times, may vary substantially. Harvest's actual production, revenues, taxes and development and operating expenditures with respect to the Corporation's reserves may vary from such estimates, and such variances could be material.

Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric calculations, probabilistic methods and upon analogy to similar types of reserves or resources, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves or resources based upon production history will result in variations, which may be material, in the estimated reserves or resources.

The reserves of Harvest's Properties as estimated by Independent Reserves Evaluators are based in part on cash flows to be generated in future years as a result of future capital expenditures. The reserves value of the properties as estimated by the Independent Reserves Evaluators may not be realized to the extent that such capital expenditures on the properties do not achieve the level of success assumed in such engineering reports.

Prices paid for acquisitions are based in part on reserves report estimates and the assumptions made in preparing the reserves report are subject to change as well as geological and engineering uncertainty.
The prices paid for acquisitions were based, in part, on engineering and economic assessments made by independent reserves valuators in the related reserves report. These assessments include a number of material assumptions regarding such factors as recoverability and marketability of crude oil, natural gas and natural gas liquids, future prices of oil, natural gas and natural gas liquids, operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond Harvest's control. In particular, the prices of and markets for petroleum and natural gas may change from those anticipated at the time of making such acquisitions. In addition, all engineering assessments involve a measure of geological and engineering uncertainty which could result in lower production and reserves than those currently attributed to Harvest's properties.

Absent capital reinvestment or acquisition and development, production levels from petroleum and natural gas properties and reserves, and cash generated, will decline over time.
Harvest's cash from operating activities, absent commodity price increases or cost effective acquisition and development activities of properties, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. Accordingly, absent additional capital investment from other sources, production levels and reserves attributable to Harvest's properties will decline.

Harvest's future petroleum and natural gas reserves and production, and therefore Harvest's cash flows, will be highly dependent on the Corporation's success in exploiting its resource base and acquiring additional reserves. Without reserves additions through acquisition or development activities, Harvest's reserves and production will decline over time as reserves are produced. There can be no assurance that Harvest will be successful in developing or acquiring additional reserves on terms that meet its investment objectives.

Harvest may be adversely affected by changes in income and capital tax laws, government incentive programs and regulations relating to the petroleum and natural gas industry.
There can be no assurance that income and capital tax laws, government incentive programs and regulations relating to the petroleum and natural gas industry, such as environmental and operating regulations, will not change in a manner which adversely affects the Corporation.

Harvest will be responsible for abandonment and reclamation costs which may be substantial.
Harvest will be responsible for compliance with terms and conditions of environmental and regulatory approvals and all laws and regulations regarding the abandonment and reclamation of the surface leases, wells, facilities and pipelines at the end of their economic life as well as those for any future expansions. Abandonment and reclamation costs may be substantial. A breach of such legislation and/or regulations may result in the imposition of fines and penalties, including an order for cessation of operations at the site until satisfactory remedies are made. It is not

possible to accurately predict the abandonment and reclamation costs since they will be a function of regulatory requirements at the time and the value of the salvaged equipment may be more or less than the abandonment and reclamation costs. In addition, in the future Harvest may determine it prudent or may be required by applicable laws, regulations or regulatory approvals to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs.

Harvest's operating cash flows will be directly affected by the applicable royalty regime.
Harvest is currently required to pay a royalty to the Governments of the Provinces of British Columbia, Alberta and Saskatchewan on Harvest's petroleum and natural gas production. These royalty regimes may be amended or supplemented from time to time. To the extent that royalty regimes are sensitive to commodity prices, the impact on Harvest of any such regime, or any amendment thereto, cannot be accurately predicted.

Harvest will be subject to risks related to BlackGold.
The development of BlackGold requires substantial capital investment to develop the asset. While Harvest makes every effort to properly and accurately forecast capital and operating expenditures, the possibility remains that capital cost overruns or schedule delays will occur as a result of fluctuating market conditions and unexpected challenges. Such cost overruns and schedule delays may negatively affect the Corporation's future financial position and cash flows.

As is the case with any large scale, technically complex project, the ongoing development of BlackGold subjects Harvest to risks associated with scheduling delays and unforeseen technical challenges. Working with a variety of vendors and suppliers, that in some cases are transporting materials across great distances, increases the risk of delays. Harvest has entered into an EPC contract with a third party to build required facilities at the BlackGold project site, including the central processing facility. To the extent that the third party fails to perform its duties as expected, risk remains that design objectives may be not be achieved and production may be reduced and/or delayed.

BlackGold is subject to government regulation. The initial phase of the project, targeting production of 10,000 bbl/d, has been approved by provincial regulators. The proposed expansion phase of the BlackGold project is in the application stage and remains subject to approval by provincial regulators. The delay of such approval could impact Harvest's ability and/or timing of reaching the targeted production of 30,000 bbl/d.

Industry competition
There is strong competition relating to all aspects of the petroleum and natural gas industry. The Upstream operations actively compete for capital, skilled personnel, undeveloped land, acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of the Upstream operations with a substantial number of other petroleum and natural gas organizations, many of which may have greater technical and financial resources than us. Some of those organizations carry on a more diverse set of petroleum and natural gas related operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw.

RISKS RELATED TO THE DOWNSTREAM OPERATIONS

The market prices for crude oil and refined products have fluctuated significantly, the direction of the fluctuations may be inversely related and the relative magnitude may be different, resulting in volatile refining margins.
The Downstream earnings and cash flows from refining and wholesale and retail marketing operations are dependent on a number of factors including fixed and variable expenses (including the cost of crude oil and other feedstocks) and the price at which Harvest is able to sell refined products. In recent years, the market prices for crude oil and refined products have fluctuated substantially. These prices depend on a number of factors beyond

Harvest's control, including the supply and demand for crude oil and refined products, which are subject to, among other things:

- changes in the global demand for crude oil and refined products;
- the level of foreign and domestic production of crude oil and refined products and their price;
- threatened or actual terrorist incidents, acts of war, and other worldwide political conditions in both crude oil producing and refined product consuming regions;
- the availability of crude oil and refined products and the infrastructure to transport crude oil and refined products;
- supply and operational disruptions including accidents, weather conditions, hurricanes or other natural disasters;
- concern over climate change or GHG emissions;
- actions of the OPEC;
- government regulations including changes in fuel specifications required by environmental and other laws;
- local factors including market conditions and the operations of other refineries in the markets in which Harvest competes; and
- the development and marketing of competitive alternative fuels.

In addition to the factors above, refinery margin is also impacted by numerous conditions including: labour, maintenance, electricity, chemicals and other inputs, unplanned production disruptions due to equipment failure, power disruptions and other factors including weather. As a result, it can be reasonably expected that Downstream results will fluctuate over time and from period to period. Harvest conducts an assessment of the carrying value of its assets to the extent required by IFRS. If refined product margins decline, the carrying value of Harvest's Downstream assets could be subject to downward revision and the Corporation's earnings could be adversely impacted. Although Harvest did not incur any impairment charges to its Downstream assets in 2011, there can be no assurance that further decline in refined product margins will not result in such impairment charges at some future dates.

Generally, fluctuations in the price of gasoline and other refined products are correlated with fluctuations in the price of crude oil; however, the prices for crude oil and prices for refined products can fluctuate in different directions as a result of worldwide market conditions. Further, the timing of the relative movement in prices as well as the magnitude of the change could significantly influence refining margins as could price changes occurring during the period between purchasing crude oil feedstock and selling the respective refined products. Harvest's Upstream operations does not produce crude oil that can be economically transported to the Refinery and, as a result, the Refinery purchases all of its crude oil feedstock at prices that fluctuate with worldwide market conditions and this could significantly impact Harvest's earnings and cash flows. Harvest also purchases refined products from third parties for sale to its customers and price changes during the period between purchasing and selling these products could also have a material adverse effect on Harvest's business and results of operations, as well as its financial condition and cash from operating activities.

Harvest purchases approximately 250,000 megawatt hours of electrical power from Newfoundland and Labrador Hydro, a provincial crown corporation. A substantial proportion of Newfoundland and Labrador Hydro's electricity is generated by hydroelectric power, a relatively inexpensive source compared to fossil fuel generators. The Refinery's cost of electrical power has remained relatively constant averaging $0.043 per kilowatt hour in 2011. Electricity prices have been and will continue to be affected by supply and demand for service in both local and regional markets and continued price increases could also have a material adverse effect on Harvest's business and results of operations, as well as its financial condition and the cash from operating activities.

Currently, the Corporation has the opportunity and intends to consider opportunities to grow its business through the reconfiguration and enhancement of its Refinery assets with a suite of expansion or debottlenecking projects.

However, if unanticipated costs occur or revenues decrease as a result of lower refining margins, operating difficulties or other matters, there may not be sufficient capital to enable us to fund all required capital and operating expenses. There can be no assurance that cash generated by Harvest's Operations or funding available from debt financings will be available to meet its capital and operating requirements.

The prices for crude oil and refined products are generally based in U.S. dollars while Harvest's operating costs are denominated in Canadian dollars, which introduces currency exchange rate exposure.

The prices for crude oil and refined products are generally based on market prices in U.S. dollars while Harvest's Downstream operating costs and capital expenditures are primarily in Canadian dollars. Fluctuations in the exchange rates between the U.S. and Canadian dollar result in currency exchange rate exposure. Although this currency exchange rate exposure may be hedged, there can be no assurance that a currency exchange rate risk management program will effectively cover all of Harvest's exposure.

Crude oil feedstock is delivered to the Refinery via waterborne vessels which could experience delays in transporting supplies due to weather, accidents, government regulations or third party actions.

The Refinery receives all of its crude oil and other feedstocks and its customers lift approximately 90% of its refined products via water borne vessels including very large crude carriers. In addition to environmental risks of handling such vessels discussed below, Harvest could experience a disruption in the supply of crude oil because of accidents, governmental regulation or third party actions. A prolonged disruption in the availability of vessels to deliver crude oil to the Refinery and/or to deliver refined products to market would have a material adverse effect on Harvest's business and results of operations, as well as the financial condition and cash from operating activities.

Since Harvest's acquisition of North Atlantic, over 67% of its crude oil feedstock has been from sources in the Middle East. The Corporation does not maintain supply commitments with any of its crude oil producers. To the extent that crude oil producers reduce the volume of crude oil produced as a result of declining production or competition or otherwise, the business, financial condition and results of operations may be adversely affected to the extent that the Corporation is not able to find a substantial amount and similar type of crude oil. Further, the Corporation has no control over the level of development in the fields that currently produce the crude oil it process at the Refinery nor the amount of reserves underlying such fields, the rate at which production will decline or the production decisions of the producers which are affected by, among other things, prevailing and projected crude oil prices, demand for crude oil, geological considerations, government regulation and the availability and cost of capital.

If MEC terminates the SOA (2011) prior to expiration or does not agree to renew the SOA (2011) upon expiration, Harvest's business could be adversely affected.

Under the SOA (2011), the Refinery receives all of its feedstock from MEC and sells almost all of the refined product produced to MEC. If MEC terminates the SOA (2011) prior to expiration or does not agree to renew the SOA (2011) upon expiration, Harvest would seek to enter into a similar agreement with another party that has a similar credit profile and expertise to that of MEC's. If Harvest were unable to enter into such a replacement agreement, it would be required to enter into separate agreements for the supply of feedstock to the Refinery and the sale of the Refinery's refined products. No assurance can be given that Harvest will be able either to enter into an agreement similar to the SOA (2011) with another party or to enter into agreements with a number of different parties to replicate the economics of the SOA (2011). If the SOA (2011) were terminated and Harvest was unable to enter into replacement agreements, revenues and cash flows from the Refinery would likely decrease, which could have a material adverse effect on Harvest's business.

Harvest is relying on the creditworthiness of MEC for Harvest's purchase of feedstock and should their creditworthiness deteriorate, crude oil suppliers may restrict the sale of crude oil to MEC.

MEC purchases crude oil feedstock to supply to North Atlantic pursuant to the SOA (2011). Accordingly, should the creditworthiness of MEC deteriorate, crude oil producers and suppliers may change their view on contracting with MEC for the supply of crude oil. Due to the large dollar amount of credit associated with the volume of crude oil purchases, any imposition of more burdensome payment terms may have a material adverse effect on MEC which could hinder its ability to supply sufficient quantities of crude oil to operate the Refinery. This in turn hinders North Atlantic's ability to operate the Refinery at full capacity. A failure to operate the Refinery at full capacity could have an adverse material effect on its business and results of operations, as well as its financial condition and cash from operating activities.

The Refinery is a single train integrated interdependent facility which could experience a major shut-down caused by an accident or be damaged by severe weather and these potential disruptions may reduce or eliminate Harvest's cash flow.

The Refinery is a single train integrated and interdependent facility which could experience a major accident, be damaged by severe weather or other natural disaster, or otherwise be forced to shut-down. A shutdown of one part of the Refinery could significantly impact the production of refined products and may reduce, and even eliminate, cash flow. Any one or more of the Refinery's processing units may require a planned turnaround or encounter unexpected downtime for maintenance or repair and the time required to complete the work may take longer than anticipated. There are no assurances that the Refinery will produce refined products in the quantities or at the cost anticipated, or that it will not cease production entirely in certain circumstances, which could have a material adverse effect on Harvest's business and results of operations, as well as its financial condition and cash from operating activities.

Harvest's refining operations are adjacent to environmentally sensitive coastal waters, and are subject to hazards and similar risks such as fires, explosions, spills and mechanical failures, any of which may result in personal injury, damage to Harvest's property and/or the property of others along with significant other liabilities in connection with a discharge of materials.

Harvest's refining operations, including the transportation of and storage of crude oil and refined products, are subject to hazards and inherent risks typical of similar operations such as fires, natural disasters, explosions, spills and mechanical failure of the equipment or third-party facilities, any of which can result in personal injury claims as well as damage to Harvest's properties and the properties of others. While Harvest carries property, casualty and business interruption insurance, the Corporation does not maintain insurance coverage against all potential losses, and could suffer losses for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on Harvest's business and results of operations, as well as its financial condition and cash from operating activities.

The operation of refineries and related storage tanks is inherently subject to spills, discharges or other releases of petroleum or hazardous substances. If any of these events had previously occurred, or occurs, in the future in connection with any of Harvest's storage tanks, or in connection with any facilities to which the Corporation sends wastes or byproducts for treatment or disposal, other than events for which the Corporation are indemnified, the Corporation could be liable for all costs and penalties associated with their remediation under federal, provincial and local environmental laws or common law, and could be liable for property damage to third parties caused by contamination from releases and spills. The penalties and clean-up costs that the Corporation may have to pay for releases or spills, or the amounts that the Corporation may have to pay to third parties for damage to their property, could be significant and the payment of these amounts could have a material adverse effect on the Corporation's business and results of operations, as well as its financial condition and cash from operating activities.

Harvest operates in environmentally sensitive coastal waters where tanker operations are closely regulated by federal, provincial and local agencies and monitored by environmental interest groups. Transportation of crude oil and refined products over water involves inherent risk and subjects us to the provisions of Canadian federal laws and the laws of the Province of Newfoundland and Labrador. Among other things, these laws require us to demonstrate Harvest's capacity to respond to a "worst case discharge" to a maximum 10,000 metric tonne oil spill. Harvest's marine division manages vessel traffic to the Refinery and works with regulatory authorities on measures to prevent and mitigate the risk of oil spills and other marine related matters. The marine division has two tugboats to assist in berthing and unberthing tankers at Harvest's dock with one tugboat equipped with fire fighting capability. The tugboat operations have a safety management system certified under the International Safety Management Code and are also certified under the International Ship and Port Security Code. In addition, Harvest has contracted the Eastern Canada Response Corporation to supplement Harvest's resources. However, there may be accidents involving tankers transporting crude oil or refined products, and response services may not respond in a manner to adequately contain a discharge and Harvest may be subject to a significant liability in connection with a discharge.

Harvest has in the past operated service stations with underground storage tanks and currently operates 55 retail gasoline stations and three commercial cardlock locations with underground storage tanks in the Province of Newfoundland and Labrador. Harvest is required to comply with provincial regulations governing such storage tanks in the Province of Newfoundland and Labrador and compliance with these requirements can be costly. The operation of underground storage tanks also poses certain other risks, including damages associated with soil and groundwater contamination. Leaks from underground storage tanks which may occur at one or more of Harvest's service stations, or which may have occurred at previously operated service stations, may impact soil or groundwater and could result in fines or civil liability. While Harvest maintains insurance in respect of such risks, there are no assurances that such insurance will be adequate to fully compensate for any liability Harvest may incur if such risks were to occur.

The production of aviation fuels subjects us to liability should contaminants in the fuel result in aircraft engines being damaged and/or aircraft accidents.

The Downstream operations produces aviation fuels, which involves inherent risks and subjects it to the provisions of Canadian federal laws. Harvest's product quality assurance programs are extensive; however, these procedures may not be sufficient to detect and prevent contaminants from entering into the aviation fuels which could result in aircraft engines being damaged and/or aircraft accidents. While the Corporation maintains insurance in respect of such risks, there are no assurances that such insurance will be adequate to fully compensate for any liability the Corporation may incur if such risks were to occur.

Refinery operations are subject to environmental regulation pursuant to local, provincial and federal legislation and require us to obtain and maintain regulatory approvals. A breach of such legislation may subject us to substantial liability and result in the imposition of fines as well as higher operating standards that may increase costs.

The Downstream operations and related properties are subject to extensive federal, provincial and local environmental and health and safety regulations governing, among other things, the generation, storage, handling, use and transportation of petroleum and hazardous substances, the emission and discharge of materials into the environment, waste management and characteristics and composition of gasoline and diesel fuels. If the Corporation fails to comply with these regulations, it may be subject to administrative, civil and criminal proceedings by governmental authorities as well as civil proceedings by environmental groups and other entities and individuals. A failure to comply, and any related proceedings, including lawsuits, could result in significant costs and liabilities, penalties, judgments against us or governmental or court orders that could alter, limit or stop the operations.

Consistent with the experience of other Canadian refineries, environmental laws and regulations have raised operating costs and required significant capital investments at the Refinery. Harvest believes that the Refinery is materially compliant with existing laws and regulatory requirements. However, material expenditures could be required in the future for the Refinery to comply with evolving environmental, health and safety laws, regulations or requirements that may be adopted or imposed in the future.

The Refinery operates under permits issued by the federal and provincial governments and these permits must be renewed periodically. The federal and provincial governments may make operating requirements more stringent which may require additional spending.

In addition, new environmental laws and regulations, new interpretations of existing laws and regulations, increased governmental enforcement or other developments could require us to make unanticipated expenditures in the Downstream operations. Many of these laws and regulations are becoming increasingly stringent, and the cost of compliance with these requirements can be expected to increase over time. Harvest is not able to predict the impact of new or changed laws or regulations or changes in the ways that such laws or regulations are administered, interpreted or enforced. The requirements to be met, as well as the technology and length of time available to meet those requirements, continue to develop and change. To the extent that the costs associated with meeting any of these requirements are substantial and not adequately provided for, there could be a material adverse effect on Harvest's business and results of operations as well as its financial condition and cash from operating activities.

Collective bargaining agreements with North Atlantic's employees and the United Steel Workers of America with respect to the Downstream operations may not prevent a strike or work stoppage and future agreements may result in an increase in operating costs.

As of December 31, 2011, 67% of full-time employees and 97% of part-time employees in the Downstream operations are represented by the United Steel Workers of America pursuant to collective bargaining agreements. Upon the expiry of existing collective agreements, the Corporation may not be able to renegotiate future collective agreements on satisfactory terms, or at all, which may result in an increase in operating costs. In addition, the existing collective agreements may not prevent a strike or work stoppage in the future, and any such work stoppage could have a material adverse effect on the Downstream business and Harvest's results of operations as well as the financial condition and cash from operating activities.

The Refinery is subject to operational risks that include severe weather, access to skilled labour, availability of materials, competing projects and equipment failures which may cause a refinery shut-down or a reduction in production thereby reducing or eliminating Harvest's cash flow.

The operation of the refinery requires physical access for people and equipment on a regular basis which could be affected by weather, accidents, government regulations or third party actions. Skilled labour is necessary to run our operations and there is a risk that we may have difficulty in sourcing skilled labour which could lead to increased operating and capital costs. There are risks and uncertainties affecting construction or planned maintenance schedules and costs, including the availability of materials, equipment, qualified personnel, impacts of competing projects drawing on the same resources during the same time period; and the potential for disruptions to operations and construction projects. Accordingly, actual costs can be materially different from estimates and could have a material adverse effect on our costs, results of operations and cash flows. In addition, maintenance activities may not improve operational performance or the output of related facilities and construction projects may not deliver anticipated results.

RISKS RELATED TO HARVEST'S STRUCTURE

Debt service and repayment

Under the Credit Facility, Harvest and certain subsidiaries of Harvest Operations (designated as restricted subsidiaries) have provided the lenders security over all of the assets of Harvest Operations and of the restricted subsidiaries, excluding the BlackGold assets. If an event of default (as defined under the Credit Facility) has occurred the lenders may demand repayment and exercise rights under the security, including sale of the secured assets. Certain payments by Harvest or the restricted subsidiaries are prohibited upon an event of default. Any indebtedness of Harvest or of restricted subsidiaries which is owed to a restricted subsidiary is subordinate to payments to lenders pursuant to the Credit Facility, under subordination agreements between the lenders and the restricted subsidiaries.

Harvest must meet certain ongoing financial and other covenants under each of the Credit Facility and the Note Indenture (respecting the 67/8% Senior Notes). The covenants include customary provisions and restrictions related to Harvest Operations' and the restricted subsidiaries' operations and activities, and are described further for each of the Credit Facility and the Note Indenture in Item 10.C of this annual report.

Harvest is permitted to borrow funds to finance the purchase of assets, incur capital expenditures, repay other obligations and finance working capital. Variations in interest rates could result in significant changes in the amount required to be applied to debt service.

Interest and principal amounts payable pursuant to the 67/8% Senior Notes are payable in U.S. dollars. Harvest is permitted to borrow funds under the Credit Facility in U.S. dollars and would be required to settle interest and principal amounts in the same currency. Variations in the Canadian/U.S. currency exchange rate could result in a significant increase in the amount of the interest and principal payments under the Credit Facility and the 67/8% Senior Notes.

Access to external capital resources
There is a risk that the Corporation will not be able to meet the covenants associated with its indebtedness, repay all or part of its indebtedness, or refinance all or part of its indebtedness on commercially reasonable terms. The occurrence of any one of these events may have a significant adverse effect on the Corporation's ability to access external capital resources. As well, to the extent that external capital, including debt financing, from banks or other creditors, becomes limited, unavailable or available on less economic terms, Harvest's ability to fund the necessary capital investments to maintain, develop, and/or expand its petroleum and/or natural gas reserves, to continue construction on its BlackGold assets and to debottleneck its refinery operations will be impaired.

Reliance on management of Harvest Operations
Holders of securities of Harvest will be dependent on the management of Harvest Operations in respect of the administration and management of all matters relating to Harvest and the Operating Subsidiaries and the Properties. Investors who are not willing to rely on the management of Harvest Operations should not invest in the Corporation.

Re-assessment of prior years' income tax returns
From time to time, Harvest Operations may take steps to organize its affairs in a manner that minimizes taxes and other expenses payable with respect to the operation of the Corporation and the Operating Subsidiaries. Harvest's prior years' income tax and royalty filings are subject to reassessment by government entities. The reassessment of previous filings may result in additional income tax expenses, royalties, interest and penalties which may adversely affect the Corporations cash flows, results from operation and financial position.

Risk management activities
The nature of Harvest's operations results in exposure to fluctuations in commodity prices, interest rates and foreign exchange rates. The Corporation monitors its exposure to such fluctuations and, where deemed appropriate, utilizes derivative financial instruments and physical delivery contracts to help mitigate the potential impact of declines in crude oil, natural gas and refined product prices, changes in interest rates and foreign exchange rates. The utilization of derivative financial instruments may introduce significant volatility into Harvest's reported net earnings, comprehensive income and cash flows. The terms of our various hedging agreements may limit the benefit to the Corporation of commodity price increases or changes in interest rates and foreign exchange rates. The Corporation may also suffer financial loss because of hedging arrangements if:

- Harvest is unable to produce petroleum, natural gas or refined products to fulfill delivery obligations;
- Harvest is required to pay royalties based on market or reference prices that are higher than hedged prices; or
- Counterparties to the hedging agreements are unable to fulfill their obligations under the hedging agreements.

To the extent that Harvest engages in these risk management activities, Harvest will be subject to counterparty risk.

ITEM 4. INFORMATION ON THE COMPANY
A. History and Development of the Company

Harvest Operations was incorporated under the ABCA on May 14, 2002. All of the issued and outstanding common shares of Harvest Operations are owned by KNOC. Established in 1979, KNOC is a leading international oil and gas exploration and production company wholly owned by the Government of Korea. KNOC's founding principle is to secure oil supplies for the nation of Korea by exploring for and developing oilfields and holding petroleum reserves. As at December 31, 2011, Harvest's gross proved reserves represented approximately 39% of KNOC's consolidated crude oil and natural gas reserves and resources. Additionally, Harvest's crude oil and natural gas production represented 29% of KNOC's consolidated 2011 petroleum and natural gas production.

Harvest Operations manages the affairs of the Operating Subsidiaries and North Atlantic, and is responsible for providing all of the technical, engineering, geological, land management, financial, administrative and commodity marketing services relating to Harvest's Upstream operations.

The head and principal office of Harvest is located at Suite 2100, 330 - 5th Avenue S.W., Calgary, Alberta T2P 0L4 and the telephone number is (403) 265-1178. The registered office of Harvest is located at Suite 4500, Bankers Hall East 855 – 2nd Street S.W., Calgary, Alberta T2P 4K7.

RECENT DEVELOPMENTS

EQUITY

In 2011, Harvest issued $505.4 million of equity to KNOC to fund the acquisition of assets from Hunt Oil Company of Canada Inc. and Hunt Oil Alberta Inc. (collectively "Hunt"). See the Capital Expenditures section below for more details.

CREDIT FACILITY

On April 29, 2011, Harvest extended the term of the Credit Facility by two years to April 30, 2015. On December 16, 2011, the Credit Facility was further amended to increase the capacity of the facility from $500 million to $800 million. Under the Credit Facility, Harvest and certain subsidiaries (designated as restricted subsidiaries) have provided the lenders security over all of the assets of Harvest Operations and of the restricted subsidiaries, excluding the BlackGold assets.

CAPITAL EXPENDITURES

The following table provides a summary of Harvest's capital expenditures in accordance with IFRS for the last two years ended December 31:

($000's)	**2011**	**2010**
Upstream capital expenditures	$ 733,380	$ 403,848
Downstream capital expenditures	284,244	71,234
Total capital expenditures	1,017,624	475,082
Acquisitions		
Business	509,829	145,144
Property	4,254	527,470
Divestitures		
Property	(8,728)	(122,788)
Net acquisition and divestiture activities	505,355	549,826
Addition to other long term assets	7,413	-
Net capital investment	$ 1,530,392	$ 1,024,908

On February 28, 2011, Harvest closed the acquisition of assets from Hunt for cash consideration of $511.0 million. KNOC provided $505.4 million of equity to fund the acquisition. An additional $25 million is payable to Hunt in the event that Canadian natural gas prices exceed certain pre-determined levels in 2012. Based on forecast gas prices at April 27, 2012, the probability of incurring this payment was assessed as low. Assets acquired include approximately 377,000 net acres of undeveloped land, with complementary land positions in Willesden Green, the Peace River Arch and Southern Alberta. This acquisition includes access to resource plays in the Willesden Green area of Alberta and the Horn River basin of British Columbia.

In 2010, Harvest Operations acquired the remaining 40% interest in Redearth Partnership and other petroleum and natural gas properties for cash consideration of $145.2 million. This amount was finalized during 2011 and the total cash consideration was revised to $144.2 million as a result of adjustments made during the measurement period.

On August 6, 2010, Harvest completed the acquisition of the BlackGold oil sands project from KNOC for $374 million. Harvest signed an EPC contract in 2010 for phase 1 of BlackGold, under which $92.4 million (including a $31.1 million deposit) has been paid to the end of 2011. Between project inception and December 31, 2011, Harvest has capitalized $122.3 million of expenditures relating to drilling and completion of observation 12 wells and EPC activities. For further information on BlackGold, refer to Item 4D “Property, Plant and Equipment” of this annual report.

Please refer to Item 4.D “Information on the Company – Property, Plant and Equipment” for details regarding the Corporation’s 2012 capital expenditure plan and Harvest’s material properties.

The following table provides a summary of Harvest’s capital expenditures in accordance with US GAAP for the year ended December 31, 2009:

($000’s)		**2009**
Upstream capital expenditures	$	186,276
Downstream capital expenditures		43,875
Total capital expenditures		230,151
Acquisitions		
Business		-
Property		2,635
Divestitures		
Property		(64,751)
Net acquisition and divestiture activities		(62,116)
Net capital investment	$	168,035

On August 11, 2009, Harvest acquired approximately 93.5% of the issued and outstanding class A shares and 90.6% of the issued and outstanding class B shares of Pegasus Oil and Gas Inc. (“Pegasus”), a natural gas weighted producer with approximately 650 boe/d of production, in exchange for Trust Units. Subsequent to August 11, 2009 and pursuant to the compulsory acquisition provisions of the Business Corporations Act (Alberta), Harvest purchased the remaining Pegasus shares and de-listed the Pegasus shares from the TSX Venture exchange. Including the obligation to assume approximately $13.9 million of bank debt, the acquisition metrics were approximately $30,000 per boe of production and approximately $4.25 per boe of reserves on a proved plus probable basis. The principal asset in this acquisition was a 7% working interest in liquids rich natural gas production from a property in the Crossfield area which is operated by Harvest. This acquisition includes access to over 150,000 acres of land and over $50 million of income tax pools.

B. Business Overview

Harvest is a significant operator in Canada's energy industry offering stakeholders exposure to an integrated structure with Upstream (exploration, development and production of crude oil, bitumen and natural gas) and Downstream (refining and marketing of distillate, gasoline and fuel oil) segments. Harvest's Upstream oil and gas production is complemented by our long-life refining business that focuses on the safe and efficient operation of a medium gravity sour-crude refinery located in the Province of Newfoundland and Labrador and the associated retail and marketing operations.

UPSTREAM

In the Upstream Operations, Harvest employs a disciplined approach to acquiring, developing and operating large resource-in-place producing properties using best-in-class technologies. Harvest's Upstream operations are principally located in the Western Canadian sedimentary basin and material properties are described in Item 4.D Property, Plant and Equipment. Harvest has a high degree of operational control as it is the operator on properties that generate the majority of Harvest's production. The Corporation believes that this "hands on" approach allows it to better manage capital expenditures and accumulate institutional expertise in its operating regions.

IMPACT OF VOLATILITY IN COMMODITY PRICES

Harvest's operational results and financial condition will be dependent on the prices received for petroleum and natural gas production. Petroleum and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, which are influenced by weather, geopolitical and general economic conditions. Any decline in petroleum and natural gas prices could have an adverse effect on Harvest's financial condition. Harvest mitigates such price risk through closely monitoring the various commodity markets and establishing commodity price risk management programs, as deemed necessary, to provide stability to its cash flows.

A summary of financial and physical contracts in respect of price risk management activities can be found in Note 23 of the consolidated financial statements for the year ended December 31, 2011 included in this annual report.

MARKETING CHANNELS

Crude Oil and NGLs

Harvest's crude oil and NGL production is marketed to a diverse portfolio of intermediaries and end users with the majority of the oil contracts existing on a 30-day continuously renewing basis and the NGL contracts on one-year terms. These commodities typically receive the prevailing monthly market prices. Harvest has a small number of condensate purchase contracts required for blending heavy oil to meet pipeline specifications. These are a combination of one year and monthly spot contracts, both at the prevailing monthly prices.

Natural Gas

Approximately 87% of Harvest's natural gas production is currently being sold at the prevailing daily spot market prices in Western Canada. Harvest receives Chicago based prices on 9% of its natural gas production relating to certain pipeline transportation commitments. The remaining 4% of production is dedicated to aggregator contracts, which are reflective of market prices and are under contract until 2015.

The following is Harvest's Upstream sales by product for each of the three years ended December 31:

In accordance with IFRS ($000's)		**2011**		**2010**
Light / medium oil sales after hedging[(1)(4)]	$	752,898	$	624,778
Heavy oil sales[(4)]		228,794		202,445
Natural gas sales[(2)]		156,942		124,226
Natural gas liquids sales[(4)]		125,507		55,385

Other[3]		22,725		170
Petroleum and natural gas sales	$	1,286,866	$	1,007,004
Royalties		(195,452)		(154,757)
Revenues	$	1,091,414	$	852,247

(1) Inclusive of the effective portion of realized gains (losses) from crude oil contracts designated as hedges.
(2) In 2011, 9% of natural gas was delivered to a pipeline that ships to the United States (2010 – nil).
(3) Inclusive of sulphur revenue and miscellaneous income.
(4) All of Harvest's crude oil and NGLs are sold in Canada.

In accordance with US GAAP *($000's)*		**2009**
Light / medium oil sales after hedging	$	502,239
Heavy oil sales		198,168
Natural gas sales		141,225
Natural gas liquids sales		44,676
Petroleum and natural gas sales[1]	$	886,308
Royalties		(128,860)
Revenues	$	757,448

(1) All of Harvest's products were sold in Canada.

PIPELINE CAPACITY

Pipeline capacity is an important consideration and may significantly impact the oil and natural gas industry if a considerable imbalance exists between pipeline capacity and export nominations. If there is a significant shortfall of export capacity, it will result in oil and gas being unable to get to market which will result in discounted pricing and/or shut-in production. Conversely, if the basin has a significant amount of excess export capacity it can make transportation more expensive, which will also have a negative effect to the netback.

COMPETITIVE CONDITIONS, SEASONALITY, AND TRENDS

Competitive conditions are included in the description of Harvest's risk factors in Item 3.D of this annual report. The exploitation and development of petroleum and natural gas reserves is dependent on physical access to production areas. Seasonal weather conditions, including freeze-up and break-up, affect such access. The seasonal accessibility increases competition for equipment and human resources during those periods.

ENVIRONMENT, HEALTH AND SAFETY POLICIES AND PRACTICES

Harvest takes an active role in the Canadian Association of Petroleum Producers ("CAPP") Responsible Canadian Energy ("RCE") program that is an association-wide performance reporting program designed to track progress of the CAPP membership in environmental, health, safety, and social performance.

In 2011, Harvest continued to take steps to build on its existing environmental, health and safety ("EH&S") management systems using the RCE framework for continuous improvement. This included formalizing the environment and regulatory components of the EH&S management system. Component improvements included creating a process for identifying potential high impact spill locations as well as a formalized risk process for classifying historical spill sites so that annual environmental budgets can be allocated appropriately. It is expected that in 2012 all components of the environment and regulatory portions of the EH&S management system will be formalized which will improve overall environmental performance.

In 2011, Harvest spent $22.1 million on the management and retirement of environmental obligations which included retirement of wells and facilities, restoration of spill sites, remediation of sites with historical contamination, and the reclamation of abandoned well sites and access roads. In 2011, Harvest had 310 active (operated) reclamation sites with 40 of these sites being submitted to regulators for reclamation certification. In addition, Harvest completed 46 surface well abandonments which will add to the number of active reclamation sites in 2012.

Enhancements to the health and safety program in 2011 included Harvest formalizing its Contractor Engagement Program for evaluating and approving third party contractors that work at Harvest sites. As a result Harvest outperformed the industry average with regard to contractor incident statistics. Additional improvements included the implementation of health and safety committees within each of the key functional groups at Harvest and revisions to the hazard identification and risk assessment processes. Finally, emergency response plans underwent the required annual review which included revising critical information within the plans and the providing training to key response personnel at Harvest.

Harvest met all regulatory compliance obligations in 2011 including the submission of the annual National Pollutant Release Inventory ("NPRI"), the BC Greenhouse Gas ("GHG") Inventory, the annual Facility Approval summary reports, the inventory of all benzene emissions from Glycol Dehydrators, the annual Caribou Protection Plans and completion of all Indian and Oil and Gas ("IOGC") required environmental audits. In addition, Harvest continued to be diligent with its Fugitive Emission Management Program, with leak detection testing conducted at 559 facilities. All repairable emission sources detected were repaired representing a reduction in GHG emissions and savings in fuel gas usage. In late 2011/early 2012, Harvest continued to improve on its GHG inventory with the initiation of the use of an on-line database that will improve data collection and reporting accuracy, as well as ensuring continued compliance with provincial regulatory bodies.

CONTROLS AND REGULATIONS

The petroleum and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of petroleum and natural gas by agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan. It is not expected that any of these controls or regulations will affect Harvest's operations in a manner materially different than they would affect other petroleum and natural gas entities of similar size. All current legislation is a matter of public record and Harvest is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the petroleum and natural gas industry.

Pricing and Marketing – Petroleum, Natural Gas and Associated Products

In the provinces of Alberta, British Columbia and Saskatchewan, petroleum, natural gas and associated products are generally sold at market index based prices. It is common to sell on an index, which is published on a daily and/or monthly basis. These indices are generated from calculations that consider volume-weighted-industry-reported purchase and sales transactions. They are generated at various sales points and are reflective of the current value of the specific commodity, adjusted for quality and location differentials. While these indices tend to directionally track benchmark prices (i.e. WTI crude oil at Cushing, Oklahoma or natural gas at Henry Hub, Louisiana), some variances can occur due to specific market imbalances. These relationships to industry reference prices can change on a monthly or daily basis depending on the supply-demand fundamentals at each location as well as other non-related market changes such as the value of the Canadian dollar.

Although the market ultimately determines the price of crude oil and natural gas, producers are entitled to negotiate sales contracts directly with purchasers. Crude oil prices are primarily based on worldwide supply and demand. The specific price depends in part on quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance and other contractual terms. Crude oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such exports has been obtained from the National Energy Board of Canada (the "NEB"). Any crude oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB and the issuance of such license requires the approval of the Governor in Council.

Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 m3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export license from the NEB and the issuance of such license requires the approval of the Governor in Council.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

Provincial Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are from time to time carved out of the Working Interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

From time to time, the federal and provincial governments in Canada have established incentive programs which have included royalty rate reductions (including for specific wells), royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects. However, the trend in recent years has been to eliminate these types of programs in favour of long-term programs which enhance predictability for producers. If applicable, oil and natural gas royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments.

Alberta

The Government of Alberta (the “Government”) implemented its New Royalty Framework (the “NRF”) effective January 1, 2009. Conventional oil royalties are set by a single sliding rate formula containing separate elements that account for oil price and well production, with royalty rates ranging up to 50% (40% effective January 2011). Natural gas royalties are also set by a single sliding rate formula, with royalty rates ranging from 5% to 50% (36% effective January 2011). Oil sands base royalty rates start at 1%, of gross revenue, and increase for every dollar when oil is priced above $55 per barrel to a maximum of 9% when oil prices reach $120 Cdn per barrel. Once the oil sands project has recovered specified allowed costs, the royalty rate will range from 25% to 40% of net operating income.

On April 10, 2008, the Government introduced two new royalty programs for the development of deep oil and natural gas reserves. A five-year oil program for exploratory wells over 2,000 meters will provide royalty adjustments up to $1 million or 12 months of royalty offsets, whichever comes first, while a natural gas deep drilling program (the "NGDDP") for wells deeper than 2,500 meters will create a sliding scale of royalty credit according to depth of up to $3,750/meter. Modifications to the NGDDP were announced on May 27, 2010 and include adjusting the vertical depth requirement to 2,000 metres and making the program an on-going feature of the Alberta royalty regime.

In November 2008, the Government announced the introduction of a five year program, the Transitional Royalty Plan (the "TRP"), which offers companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 meters) a one-time option, on a well-by-well basis, to reduced royalty rates for new wells for a maximum period of five years to December 31, 2013 after which all wells convert to the NRF. To qualify for this program, wells must be drilled between November 19, 2008 and December 31, 2013. This program was amended on May 27, 2010 such that no new wells will be allowed to select transitional royalty rates effective January 1, 2011 and wells that have selected the transitional royalty rates will have the option to switch to the new rates effective January 1, 2011.

On March 3, 2009, the Government announced a new three-point stimulus plan and extended the plan to two years on June 25, 2009. The Drilling Royalty Credit for new conventional oil and natural gas wells is a two-year program effective for wells spud on or after April 1, 2009. It will provide a $200 per-metre-drilled royalty credit, with the maximum credit determined on a sliding scale based on the individual Corporation's total Alberta-based, 2008 Crown oil and gas production. The New Well Royalty Rate is also effective April 1, 2009 for new conventional oil and natural gas wells. It will provide a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas per well, to all new wells that begin producing conventional oil or natural gas between April 1, 2009 and March 31, 2011 (announced as a permanent feature of the Alberta royalty regime on May 27, 2010). The third point is an abandonment and reclamation fund which will provide $30 million to be invested by the Orphan Well Association to abandon and reclaim old well sites where there is no legally responsible or financially able party available.

On May 27, 2010, in addition to announcing changes to existing programs, the Government implemented the Horizontal Oil and Gas New Well Royalty Rates, retroactive to wells that commence drilling on or after May 1, 2010, to provide upfront royalty adjustments to new horizontal wells. Qualifying oil wells will receive a maximum royalty rate of 5 percent for all products with volume and production month limits set according to the depth of the well. Qualifying gas wells will also receive a maximum royalty rate of 5 percent for all products for 18 producing months, with a volume limit of 500 million cubic feet of gas equivalent production.

On January 28, 2011, the Minister of Energy, Ron Liepert, announced that the Alberta Government had accepted the recommendations of the Regulatory Enhancement Task Force, including the proposal to consolidate a variety of upstream oil and gas regulatory functions into the authority of a single regulator. These changes are intended to streamline the approval process for projects, resulting in more consistency, less duplication and greater certainty to the regulatory regime in Alberta.

Saskatchewan

In Saskatchewan, the amount payable as a Crown royalty or freehold production tax in respect of crude oil depends on the type, value, quantity produced in a month and vintage. Crude oil type classifications are "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". Vintage categories applicable to each of the three crude oil types are old, new, third tier and fourth tier. Crude oil rates are also price sensitive and vary between the base royalty rates of 5% for all fourth tier oil to 20% for old oil. Marginal royalty rates, applied to the portion of the price that is above the base price, are 30% for all fourth tier oil to 45% for old oil.

The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the amount obtained by the producer and a prescribed minimum price. As an incentive for the marketing of natural gas produced in association with oil, a lower royalty rate is assessed than the royalty payable on non-associated natural gas. The rates and vintage categories of natural gas are similar to oil.

On June 19, 2007, a new orphan oil and gas well and facility program was introduced, solely funded by oil and gas companies to cover the cost of cleaning up abandoned wells and facilities where the owner cannot be located or has gone out of business. The program is composed of a security deposit, based upon a formula considering assets of the well and the facility licensee against the estimated cost of decommissioning the well and facility once it is no longer producing, and an annual levy assessed to each licensee.

On May 27, 2010, the Government of Saskatchewan announced an incentive to encourage increased natural gas exploration and production in the province. The volume-based incentive establishes a maximum Crown royalty rate of 2.5 per cent and a freehold production tax rate of zero per cent on the first 25 million cubic metres of natural gas produced from every horizontal gas well drilled between June 1, 2010 and March 31, 2013.

British Columbia

The British Columbia royalty regime for oil is dependent on age and production. Oil is classified as "old", "new" or "third tier" and a separate formula is used to determine the royalty rate depending on the classification. The rates are further varied depending on production. Lower royalty rates apply to low productivity wells and third tier oil to reflect the increased cost of exploration and extraction. There is no minimum royalty rate for oil.

The British Columbia natural gas royalty regime is price-sensitive, using a "select price" as a parameter in the royalty rate formula. When the reference price, being the greater of the producer price or the Crown set posted minimum price ("PMP"), is below the select price, the royalty rate is fixed. The rate increases as prices increase above the select price. The Government of British Columbia determines the producer prices by averaging the actual selling prices for gas sales with shared characteristics for each company minus applicable costs. If this price is below the PMP, the PMP will be the price of the gas for royalty purposes.

Natural gas is classified as either "conservation gas" or "non-conservation gas". There are three royalty categories applicable to non-conservation gas, which are dependent on the date on which title was acquired from the Crown and on the date on which the well was drilled. The base royalty rate for non-conservation gas ranges from 9% to 15%. A lower base royalty rate of 8% is applied to conservation gas. However, the royalty rate may be reduced for low productivity wells.

In May 2008, the Government of British Columbia introduced the Net Profit Royalty Program to stimulate development of high risk and high cost natural gas and oil resources in British Columbia that are not economic under other royalty programs. The program allows for the calculation of royalties based on the net profits of a particular project and is governed under the Net Profit Royalty Regulation, which came into effect in May 2008.

On August 6, 2009, the Province of British Columbia announced an Oil and Gas Stimulus package providing for a one-year, two per cent royalty rate for all natural gas wells drilled in a 10 month window (September 2009 - June 2010), an increase of 15 per cent in the existing royalty deductions for natural gas deep drilling, and a qualification of horizontal wells drilled between 1,900 and 2,300 metres into the Deep Royalty Credit Program. An additional $50 million was allocated in the fall of 2009 for the Infrastructure Royalty Credit Program to stimulate investment in oil and gas roads and pipelines.

Land Tenure

Crude oil and natural gas located in western Canada is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

RESERVES AND OTHER OIL AND GAS INFORMATION

Harvest retained qualified Independent Reserves Evaluators to evaluate and prepare reports on 100% of Harvest's crude oil and natural gas proved plus probable reserves as of December 31, 2011; no attempt was made to evaluate possible reserves. Harvest's reserves were evaluated by McDaniel (who evaluated approximately 17% of Harvest's total proved plus probable reserves), and GLJ (who evaluated approximately 83% of Harvest's total proved plus probable reserves). All of Harvest's reserves were evaluated using the cost assumptions as at December 31, 2011 and the average first-day-of-the-month prices for the period ended December 31, 2011. All of Harvest's reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan. See Items 19.15.1 and 19.15.2 of this annual report for Independent Reserve Evaluators' reports on evaluation methodology.

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

Description of Harvest's Internal Controls Used in Reserve Estimation

The person primarily responsible for overseeing the year-end reserves evaluation is the Vice President ("VP"), Engineering, Jim Sheasby, Professional Engineer who has been at Harvest since February 2006.

Independent Reserves Evaluators are selected and appointed by one of Harvest's Board committees, the Upstream Reserves, Safety and Environment Committee ("Reserves Committee"), with assistance from the VP, Engineering. Each evaluator's qualifications, industry experience and experience with Harvest's assets are reviewed to enable the Reserves Committee to approve the selection of Independent Reserves Evaluators. Normally, more than one Independent Reserves Evaluator would be appointed to ensure independence. The allocation of assets to be reviewed by each Independent Reserves Evaluator is based on the evaluator's expertise, information databases and past experience in evaluating the relevant properties. The allocations are reviewed by the VP, Engineering to ensure that there is no duplication of areas.

For 2011, Harvest engaged GLJ and McDaniel to undertake the year-end evaluation. Harvest supplied accounting data, land data and well files for any new drills to the evaluators in order for them to initiate their review process. Internally, Harvest also conducted technical review meetings on major properties to highlight activity that was undertaken through the course of the year. Computer software is used to establish the appropriate level of certainty for reserves estimates. The evaluators took the initial data and prepared draft reports for review. Reports were logged by Harvest's reserves coordinator and then forwarded to individual property teams for detailed review. This process continued until the final updated reports were received.

The VP, Engineering reviews the final reports, ensuring that they are consistent with the previous reports and that appropriate changes have been made. After completing the review, the VP, Engineering presents the reports to the Reserves Committee together with a memo highlighting the significant changes from the prior year, including a reconciliation to gain an understanding of the additions, deletions and revisions made since the previous report. This memo is reviewed with the Reserves Committee by the VP, Engineering and key areas and significant differences between management and the Independent Reserves Evaluators are discussed.

A due diligence checklist is used by the Reserves Committee in reviewing the process to ensure comfort over the use of definitions, independence and qualifications. In addition, the Independent Reserves Evaluator attests to the Reserves Committee that the Reserves Report satisfies NI 51-101 and SEC definitions; this representation is also included in the final signed reports.

Net Reserves (Harvest's Share After Royalties)

The following table sets forth a summary of oil and natural gas reserves prepared by Harvest using constant pricing in accordance with the SEC's guidelines as of December 31, 2011. The year-end numbers represent estimates derived from the Reserve Reports. The recovery and reserve estimates of Harvest's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. Refer to Item 3.D "Risk Factors" of this annual report for discussion on the uncertainties involved in estimating our reserves.

The crude oil, natural gas liquids and natural gas reserve estimates presented are based on the definitions provided in the SEC's regulations. A summary of these definitions are set forth below:

(a) **Net reserves** are the remaining reserves of Harvest, after deduction of estimated royalties and including royalty interests.
(b) **Proved reserves** are the estimated quantities of crude oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.
(c) **Probable reserves** estimates are provided as optional disclosure under the SEC regulations. Probable reserves are those additional reserves that are less certain to be recovered than proved, however, together with proved are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) **Developed** reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
(b) **Undeveloped** reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Estimates of total net proved crude oil or natural gas reserves are not filed with any U.S. federal authority or agency other than the SEC.

	Reserves					
	Light and Medium Oil[1]		**Heavy Oil[1]**		**Bitumen**	
	Gross (Mbbls)	**Net (Mbbls)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mbbls)**	**Net (Mbbls)**
Proved						
Developed producing	51,334	45,914	34,739	31,521	-	-
Developed non-producing	1,288	1,112	1,335	1,115	-	-
Undeveloped	9,650	8,302	3,181	2,666	93,483	82,237
Total proved	62,272	55,328	39,255	35,302	93,483	82,237
Probable	26,206	23,284	16,975	14,651	165,762	138,847
Total proved plus	88,478	78,612	56,230	49,953	259,245	221,084

probable						

	Reserves					
	Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
Proved						
Developed producing	231,867	206,968	11,058	8,015	135,775	119,944
Developed non-producing	21,735	19,606	793	620	7,039	6,115
Undeveloped	60,098	53,800	1,930	1,596	118,261	103,767
Total proved	313,700	280,374	13,781	10,231	261,075	229,826
Probable	139,138	124,271	7,197	5,323	239,330	202,817
Total proved plus probable	452,838	404,645	20,978	15,554	500,405	432,643

(1) The reserves attributable to Harvest's Hay River property, which is an area that produces medium gravity crude oil (average 24° API), are subject to a heavy oil royalty regime in British Columbia and would be required, under NI 51-101, to be classified as heavy oil for that reason. Harvest has presented Hay River reserves as medium gravity crude in the reserves tables above as they would otherwise be classified in this fashion were it not for the lower rate royalty regime applied in British Columbia. If the Hay River reserves were included in the heavy crude oil category, it would increase the gross heavy oil reserves and reduce the gross light/medium oil reserves by the following amounts: Proved Developed Producing: 12.2 MMbbl (10.8 MMbbl net), Proved Undeveloped: 5.0 MMbbl (4.1 MMbbl net), Total Proved: 17.2 MMbbl (14.9 MMbbl net), Probable: 5.9 MMbbl (5.4MMbbl net) and Proved plus Probable: 23.1 MMbbl (20.3 MMbbl net).

Undeveloped Reserves

As at December 31, 2011, Harvest has a total of 125.3 MMboe of gross reserves that are classified as proved non-producing, and of these non-producing reserves approximately 94% are undeveloped reserves. The balance are developed non-producing reserves which would be wells that are not currently producing and are eligible to be brought on production given economics and production information as at December 31, 2011. Substantially all of the undeveloped reserves are based on Harvest’s then current 2012 budget and long range development plans for the major assets noted elsewhere in this document. Approximately 22% of the conventional undeveloped reserves are expected to be developed within the next two years. The remaining conventional undeveloped reserves are expected be developed over the next five years, in most cases due to processing facility capacity restrictions. The undeveloped reserves assigned to the BlackGold oil sands project are forecast to be developed over the next 25 years. The capital cost has been taken into account for these programs in the estimated future net revenue.

During 2011, Harvest drilled a gross total of 251.0 wells (214.3 net) with the vast majority of the development taking place in the following properties: Hay River, Red Earth, Rimbey, Markerville, West Central, Lloydminster, Hayter, Murray Lake and Kindersley. The bulk of the wells drilled had been previously assigned proved undeveloped (PUD) reserves and therefore these reserves were converted to proved developed. Total PUD reserves converted during 2011 were gross 11.1 MMboe with related capital expenditures of approximately $238.4 million.

New PUD reserves were also assigned during the 2011 year-end evaluation recognizing the ongoing development of Harvest’s properties. Total gross PUD reserves added for the 2011 year-end evaluation were 10.1 MMboe.

There are no material amounts of PUD reserves that have remained undeveloped for five years or more after disclosure as proved undeveloped reserves.

Production Volumes

	Production Volumes — 2011				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Natural Gas *(Mcf/d)*	112,360	121,547	124,259	111,291	91,888
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil[(1)]	24,380	26,106	23,621	22,294	25,523
Heavy Oil	8,992	9,521	8,825	8,559	9,038
Natural Gas Liquids	5,062	5,440	5,392	5,937	3,455
Total Oil and Natural Gas Liquids	38,434	41,067	37,838	36,790	38,016
Total (*boe/d*)	57,161	61,324	58,548	55,338	53,331

	Production Volumes — 2010				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Natural Gas *(Mcf/d)*	80,881	82,837	79,147	79,797	81,752
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil[(1)]	24,077	24,079	22,886	24,874	24,487
Heavy Oil	9,253	9,433	9,235	9,090	9,250
Natural Gas Liquids	2,587	2,736	2,465	2,334	2,816
Total Oil and Natural Gas Liquids	35,917	36,248	34,586	36,298	36,553
Total (*boe/d*)	49,397	50,054	47,777	49,597	50,178

	Production Volumes — 2009				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Natural Gas *(Mcf/d)*	90,097	83,610	89,163	92,335	95,421
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil[(1)]	23,651	23,281	22,793	24,316	24,233
Heavy Oil	10,261	9,491	10,066	10,365	11,141
Natural Gas Liquids	2,718	2,714	2,648	2,675	2,837
Total Oil and Natural Gas Liquids	36,630	35,486	35,507	37,356	38,211
Total (*boe/d*)	51,646	49,421	50,368	52,745	54,115

Per-Unit Results

	Per-Unit Results — 2011				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Natural Gas and Natural Gas					

Liquids ($/boe)					
Average sales price	32.53	31.02	32.82	34.62	31.46
Royalties	4.58	4.93	3.61	7.76	1.28
Operating expenses(2)	11.40	12.01	11.33	11.33	10.73
Netback(3)	16.55	14.08	17.88	15.53	19.45
Crude Oil — Light and Medium(1) ($/bbl)					
Average sales price	85.67	89.90	80.43	94.08	78.69
Royalties	14.01	15.00	14.29	15.21	11.65
Operating expenses(2)	20.60	20.22	20.52	20.41	21.23
Netback(3)	51.06	54.68	45.62	58.46	45.81
Crude Oil — Heavy ($/bbl)					
Average sales price	69.71	79.28	62.84	74.84	61.51
Royalties	9.45	9.56	8.98	10.81	8.53
Operating expenses(2)	20.78	22.23	20.11	20.12	20.53

	Per-Unit Results — 2011				
	Year	Q4	Q3	Q2	Q1
Netback(3)	39.48	47.49	33.75	43.91	32.45
Crude Oil — Total ($/bbl)					
Average sales price	81.37	87.06	75.65	88.74	74.20
Royalties	12.78	13.54	12.84	13.99	10.83
Operating expenses(2)	20.65	20.76	20.41	20.33	21.05
Netback(3)	47.94	52.76	42.40	54.42	42.32
Total ($/boe)					
Average sales price	62.13	64.61	57.85	66.73	59.19
Royalties	9.37	9.93	8.72	11.23	7.47
Operating expenses(2)	16.80	17.09	16.36	16.35	17.42
Netback(3)	35.96	37.59	32.77	39.15	34.30

	Per-Unit Results — 2010				
	Year	Q4	Q3	Q2	Q1
Natural Gas and Natural Gas Liquids ($/boe)					
Average sales price	30.67	29.12	27.39	30.34	35.80
Royalties	4.69	3.15	2.99	4.32	8.29
Operating expenses(2)	11.16	10.68	11.83	11.92	10.27
Netback(3)	14.82	15.29	12.57	14.10	17.24
Crude Oil — Light and Medium(1) ($/bbl)					
Average sales price	71.09	73.44	67.71	68.78	74.35
Royalties	10.48	10.97	10.29	11.59	9.01
Operating expenses(2)	16.28	17.43	15.48	15.64	16.55
Netback(3)	44.33	45.04	41.94	41.55	48.79
Crude Oil — Heavy ($/bbl)					
Average sales price	59.94	58.82	58.52	56.51	65.98
Royalties	10.42	10.36	9.11	10.66	11.57
Operating expenses(2)	16.90	17.03	16.17	19.31	15.10
Netback(3)	32.62	31.43	33.24	26.54	39.31
Crude Oil — Total ($/bbl)					

Average sales price	68.00	69.33	65.07	65.49	72.06
Royalties	10.46	10.80	9.95	11.34	9.71
Operating expenses(2)	16.45	17.32	15.68	16.62	16.16
Netback(3)	41.09	41.21	39.44	37.53	46.19
Total ($/boe)					
Average sales price	55.85	56.03	52.71	54.41	60.17
Royalties	8.58	8.27	7.67	9.13	9.25
Operating expenses(2)	14.73	15.12	14.42	15.14	14.23
Netback(3)	32.54	32.64	30.62	30.14	36.69

	Per-Unit Results — 2009				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Natural Gas and Natural Gas Liquids ($/boe)					
Average sales price	28.70	32.37	23.16	26.04	33.38
Royalties	3.42	3.55	3.07	1.98	5.05
Operating expenses(2)	10.91	11.14	10.06	10.15	12.26
Netback(3)	14.37	17.68	10.03	13.91	16.07
Crude Oil — Light and Medium(1) ($/bbl)					
Average sales price	58.18	70.09	64.57	57.54	40.99
Royalties	9.10	12.99	10.05	8.12	5.35
Operating expenses(2)	15.76	14.95	15.10	14.65	18.31
Netback(3)	33.32	42.15	39.42	34.77	17.33
Crude Oil — Heavy ($/bbl)					
Average sales price	52.91	62.62	58.57	55.12	37.16
Royalties	7.52	8.12	10.54	7.39	4.34
Operating expenses(2)	13.89	14.46	13.45	12.95	14.69
Netback(3)	31.50	40.04	34.58	34.78	18.13

Crude Oil — Total ($/bbl)					
Average sales price	56.59	67.93	62.73	56.82	39.78
Royalties	8.62	11.58	10.20	7.90	5.03
Operating expenses(2)	15.19	14.80	14.59	14.14	17.17
Netback(3)	32.78	41.55	37.94	34.78	17.58
Total ($/boe)					
Average sales price	47.02	55.94	48.97	46.28	37.56
Royalties	6.84	8.87	7.72	5.88	5.04
Operating expenses(2)	13.72	13.57	13.02	12.77	15.47
Netback(3)	26.46	33.50	28.23	27.63	17.05

(1) Medium oil production includes production from Harvest's Hay River property. The crude oil from this property has an average API of 24^0 (medium grade); however, it benefits from a heavy oil royalty regime and therefore, would be classified as heavy oil according to NI 51-101.

(2) Before gains or losses on commodity derivatives.

(3) This is a non-GAAP measure. Please see "Non-GAAP Measures" in this annual report. Netbacks are calculated by subtracting royalties and operating expenses before gains or losses on commodity derivatives and transportation expenses.

Drilling Activity

The following tables summarize Harvest's gross and net interest in wells drilled for the periods indicated.

	2011			
	Exploratory Wells		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Oil Wells	15	14.0	163	145.0
Gas Wells	1	1.0	37	20.8
Service Wells	3	3.0	25	25.0
Dry Holes	7	5.5	-	-
Total Wells	26	23.5	225	190.8

	2010			
	Exploratory Wells		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Oil Wells	12	10.6	139	118.1
Gas Wells	5	4.4	9	3.2
Service Wells	-	-	5	5.0
Dry Holes	1	0.1	-	-
Total Wells	18	15.1	153	126.3

	2009			
	Exploratory Wells		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Oil Wells	-	-	42	35.1
Gas Wells	-	-	38	15.7
Service Wells	1	1	25	24.5
Dry Holes	-	-	1	0.3
Total Wells	1	1	106	75.6

Present Activities

Conventional

At December 31, 2011 Harvest was in the process of drilling a gross total of 10 wells (9.8 net) which was the beginning of the 2012 capital program (estimated to be approximately $436 million with a focus on oil projects). In Hay River there were 3 gross horizontal oil wells and 4 gross injectors all targeting the Bluesky formation; in Red Earth there were 2 gross Horizontal Slave Point oil wells and in the Deep Basin there was one gross horizontal Falher liquids gas well. Harvest also plans to continue with its enhanced oil recovery projects in the larger oil reservoirs at Hay River, Wainwright and Suffield.

Oil Sands

At December 31, 2011 engineering, procurement and construction of the facilities for the BlackGold oil sands project were in progress, as well as detailed engineering and fabrication of major equipment. Site preparation was completed and Harvest was in the process of drilling 15 SAGD well pairs.

Location of Wells
The following table summarizes Harvest's interests in producing wells and wells capable of producing as at December 31, 2011.

	Gas		Oil		Total(1)(2)	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	3,019	1,127	4,499	3,351	7,518	4,478
British Columbia	166	125	538	299	704	424
Saskatchewan	63	95	1,613	1,317	1,676	1,412
Total	3,248	1,347	6,650	4,967	9,898	6,314

(1) Harvest has varying royalty interests in 700 natural gas wells and 240 crude oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: 41 gross natural gas wells (19.1 net wells) and 21 gross crude oil wells (11.2 net well).

Developed and Undeveloped Acreage

The following table summarizes Harvest's developed, undeveloped and total landholdings as at December 31, 2011.

	Developed(1)		Undeveloped(2)		Total	
(thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	1,310	734	781	543	2,091	1,277
British Colombia	142	79	309	192	451	271
Saskatchewan	89	81	91	81	180	162
Total	1,541	894	1,181	816	2,722	1,710

The following table summarizes Harvest's developed and undeveloped land holdings, expiring within one year from December 31, 2011.

	Developed(1)		Undeveloped(2)		Total	
(thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	29	23	86	71	115	94
British Colombia	4	3	62	49	66	52
Saskatchewan	2	2	18	18	20	20
Total	35	28	166	138	201	166

(1) Developed acreage is acreage assignable to productive wells; productive wells include producing wells and wells mechanically capable of producing.

(2) Undeveloped acreage encompasses those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves. Users of this information should not confuse undeveloped acreage with undrilled acreage held by production under the terms of the lease.

Harvest conducts ongoing development activity to retain land that would otherwise expire. As a result of this activity, the actual land holdings that will expire within one year may be less than indicated above.

Delivery Commitments
Harvest does not have any material delivery commitments; commitments relating to transportation agreements have been disclosed in the "transportation agreements" under Item 5.F "Tabular Disclosure of Contractual Obligations".

DOWNSTREAM
Harvest's Downstream business, operating under the North Atlantic trade name, is comprised of a medium gravity sour crude oil hydrocracking refinery with a 115,000 barrels per stream day nameplate capacity and a petroleum marketing business (the "Marketing Division") that is composed of five business segments. All of the Downstream operations are located in the Province of Newfoundland and Labrador.

Refining is primarily a margin based business in which the feedstocks and the refined products are commodities. Both crude oil and refined products in each regional market react to a different set of supply/demand and transportation pressures and refiners must balance a number of competing factors in deciding what type of crude oil to process, what kind of equipment to invest in and what range of products to manufacture. As most refinery operating costs are relatively fixed, the goal is to maximize the yield of high value refined products and to minimize crude oil and other feedstock costs. The value and yield of refined products are a function of the refinery equipment and the characteristics of the crude oil feedstock, while the cost of feedstock depends on the type of crude oil. The refining industry depends on its ability to earn an acceptable rate of return in its marketplace where prices are set by international as well as local markets.

PRODUCTS AND MARKETS

Refining Business
An oil refinery is a manufacturing facility that uses crude oil and other feedstocks as raw materials and produces a variety of refined products. The actual mix of refined products from a particular refinery varies according to the refinery's processing units, the specific refining process utilized and the nature of the feedstocks. The refinery processing units generally perform one of three functions: separating different types of hydrocarbons in crude oil, converting the separated hydrocarbons into more desirable or higher value products or chemically treating the products to remove unwanted elements and components such as sulphur, nitrogen and metals. Refined products are typically differing grades of gasoline, diesel fuel, jet fuel, furnace oil and heavier fuel oil.

The Refinery produces high quality gasoline, ultra low sulphur diesel, jet fuel, furnace oil, and High Sulphur Fuel Oil ("HSFO"). Approximately 10-15% of North Atlantic's refined products are sold in the Province of Newfoundland and Labrador while approximately 70-85% is export cargos sold to MEC under the SOA (2011). Such cargos are shipped by MEC to U.S. east coast markets such as Boston, New York City and in Europe, or farther abroad, when economics justify the increased shipping charge. During 2011, North Atlantic sold the majority of its distillates, gasoline products and HSFO to Vitol pursuant to the SOA and to MEC pursuant to the SOA (2011), with the remaining products sold in Newfoundland through the petroleum marketing division. Please refer to Item 10.C "Material Contracts" for further information regarding the SOA (2011). North Atlantic's business and operating results are dependent on the SOA (2011) and the SOA partner, further discussion can be found at Item 3.D "Risk Factors" of this annual report.

The following table shows Downstream's sales by product for the years ended December 31:

In accordance with IFRS *($000's)*	**2011**	**2010**
Gasoline products	$ 1,055,020	$ 985,737
Distillates	1,385,985	1,251,160
High sulphur fuel oil	628,518	744,628
Total sales	$ 3,069,523	$ 2,981,525

In accordance with US GAAP *($000's)*	**2009**
Gasoline products	$ 851,850

Distillates	972,872
High sulphur fuel oil	467,249
Total sales	$ 2,291,971

The following table provides the total amount of Downstream's export sales for the years ended December 31:

In accordance with IFRS	**2011**	**2010**
Total export sales (*$000's*) [(1)]	$2,349,521	$2,328,653
Export sales as a percentage of total Downstream sales	77%	78%

(1) Export sales are primarily to the U.S. market with only an immaterial amount exported to Europe.

In accordance with US GAAP	**2009**
Total export sales (*$000's*) [(1)]	$1,869,686
Export sales as a percentage of total Downstream sales	82%

(1) Export sales are primarily to the U.S. market with only an immaterial amount exported to Europe.

The Marketing Division is headquartered in St. John's, Newfoundland and is composed of the following five business segments:

Retail Gasoline Business
North Atlantic's retail gasoline business operates 55 retail gasoline stations (including 39 locations branded as "North Atlantic" and 10 locations branded as "Home Town"; a secondary brand for small market areas and the remaining 6 locations unbranded) and 3 commercial cardlock locations. Most locations include a convenience store which is independently operated, except for 7 branded locations, which are fully operated by North Atlantic and 1 franchise location which is referred to as "Orange Store." In 2011, the volume of gasoline sold at these retail locations represented a market share of approximately 23% of the Newfoundland market. The major competitors in the Newfoundland market are Irving Oil, Imperial Oil and Ultramar.

Retail Heating Fuels Business
North Atlantic's retail heating fuels business delivers furnace oil and propane to approximately 20,000 residential heating and commercial customers throughout Newfoundland with about 75% of the demand for furnace oil, 24% for propane and 1% kerosene.

Commercial Business
North Atlantic delivers distillates, jet fuel, propane and high sulphur fuel oil to commercial heating, marine, aviation, trucking and construction industries from seven storage terminals.

Wholesale Business
North Atlantic provides distillates, jet fuel and propane to a number of wholesale customers from both its wharf and truck rack facilities.

Bunker Business
North Atlantic sells bunkers to crude oil and refined product vessels at its wharf facilities.

TRANSPORTATION
The Refinery enjoys a significant transportation advantage as a result of its ice-free, deep water docking facility and it has approximately seven million barrels of tankage, including six 575,000 barrel crude tanks. This enables the receipt of crude oil transported on very large crude carriers which typically result in significantly lower per barrel transportation charges. North Atlantic's dock facilities are used for off-loading refinery feedstocks and for loading refined products. The dock facilities handle approximately 220 vessels each year, with North Atlantic owning and operating two tugboats to assist with berthing and unberthing tankers.

GROSS MARGIN
Refining gross margin is a function of the sales value of the refined products produced and the cost of crude oil and other feedstocks purchased as well as the yield of refined products from various feedstocks. North Atlantic continuously evaluates the market and relative refinery values of several different crude oils and vacuum gas oils ("VGO") to determine the optimal feedstock mix. North Atlantic also analyzes the refining gross margin for its sales revenue relative to refined product benchmark prices and the WTI benchmark prices. With respect to feedstock costs, North Atlantic analyzes price discounts relative to the WTI benchmark prices and segregate crude oil sources by country of origin for reporting. See the Downstream risk factors included in Item 3.D of this annual report for a discussion on the volatility of refining margins due to fluctuations in market prices for crude oil feedstocks and refined products.

FEEDSTOCK
The Refinery's crude oil and other feedstocks are waterborne cargos originating primarily from Iraq, Russia and South America. North Atlantic purchases substantially all of its refinery feedstock from MEC pursuant to the SOA (2011). Typically, there are approximately 20 days of crude oil feedstock in tankage at the Refinery to mitigate the effects of any supply disruptions. A discussion on the volatility of feedstock prices is included in Item 3.D "Risk Factors" of this annual report.

ENVIRONMENT, HEALTH AND SAFETY POLICIES AND PRACTICES
The Downstream operations have an active and comprehensive Integrated Management System to promote the integration of safety, health and environmental awareness into the Refinery and related businesses. The Refinery is continuing to benefit from previous Workplace Health, Safety and Compensation Commission audits and claims history with workers' compensation assessment rates reduced again for the ninth consecutive year. In 2011, the Refinery was in compliance with Provincial Air Quality and Federal Effluent Regulations.

CONTROLS AND REGULATIONS
The petroleum refining industry is subject to extensive controls and regulations governing its operations (including marine transportation, refined product specifications, emissions and marketing) imposed by legislation enacted by various levels of government all of which should be carefully considered by investors. It is not expected that any of these controls or regulations will affect the Downstream operations in a manner materially different than they would affect other petroleum refining entities of similar size. All current legislation is a matter of public record and Harvest is unable to predict what additional legislation or amendments may be enacted.

Pricing (Marketing Division)
Since 2001, the sales price of residential home heating fuels and automotive gasoline and diesel fuel sold for consumption within the Province of Newfoundland and Labrador is subject to regulation under the Petroleum Products Act (Newfoundland), administered by the Public Utilities Board. Under this act, the Pricing Commissioner has the authority to set the maximum wholesale and retail prices that a wholesaler and a retailer may charge and to determine the minimum and maximum mark-up between the wholesale price to the retailer and the retail price to the consumer in the Province of Newfoundland and Labrador. The wholesale and retail prices of petroleum products are adjusted weekly based on the New York Harbour benchmark price for these products.

ENVIRONMENTAL REGULATION
The oil and natural gas industry is subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites are abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties.

The Canadian Government has indicated its commitment to reduce GHG emissions and will be making changes to environmental legislation for criteria air contaminants but has provided no specific target guidelines or policies that relate to the oil and gas industry. Such legislation could have potentially adverse effects on both Harvests' Upstream and Downstream financial results. Harvest will participate in the discussion of any initiatives whether at a Federal or Provincial government level and will be able to determine if there is any financial impact once guidelines are established. On an ongoing basis, Harvest continues to undertake projects that reduce emission of GHGs such as evaluating the injection of carbon dioxide into oil reservoirs and the further capture of fugitive emissions in our field operations as part of our annual capital program.

In 2002, the Government of Canada ratified the Kyoto Protocol which calls for Canada to reduce its GHG emissions to specified levels. On April 26, 2007, the Government of Canada released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan") which includes a regulatory framework for air emissions. This Action Plan is to regulate the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. On March 10, 2008, the Government of Canada released "Turning the Corner", outlining additional details to implement their April 2007 commitment to cut GHG emissions by an absolute 20% by 2020. "Turning the Corner" sets out a framework to establish a market price for carbon emissions and sets up a carbon emission trading market to provide incentives for Canadians to reduce their GHG emissions. In addition, the regulations include new measures for oil sands developers that require an 18% reduction from 2006 levels by 2010 for existing operations and for oil sands operations commencing in 2012, a carbon capture and storage capability. There is no mention of targeting reductions for unintentional fugitive emissions for conventional producers. Companies will be able to choose the most cost effective way to meet their emissions reduction targets from in-house reductions, contributions to time-limited technology funds, domestic emissions trading and the United Nations' Clean Development Mechanism. Companies that have already reduced their GHG emissions prior to 2006 will have access to a limited one-time credit for early adoption. Giving the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, and the lack of detail in the Government of Canada's announcement, it is not possible to assess the impact of the requirements on our operations and financial performance.

Harvest's environmental compliance is governed by various statutes including: Alberta's Environmental Protection and Enhancement Act, British Columbia's Environmental Assessment Act, Saskatchewan's Environmental Assessment Act, and Newfoundland's Environmental Protection Act.

Alberta
In 2007, the Government of Alberta introduced the Climate Change and Emissions Management Amendment Act which intends to reduce GHG emissions intensity from large emitting facilities. On January 24, 2008, the Government of Alberta announced their plan to reduce projected emissions in the province by 50% under the new climate change plan by 2050. This will result in reductions of 14% below 2005 levels. The Government of Alberta stated they will form a government-industry council to determine a go-forward plan for implementing technologies, which will significantly reduce greenhouse gas emissions by capturing air emissions from industrial sources and locking them permanently underground in deep rock formations.

On April 5, 2011, the Government of Alberta released their draft of the Lower Athabasca Regional Plan ("LARP"), which was developed as part of the land-use framework under the Alberta Land Stewardship Act. The draft was subsequently updated on August 29, 2011 based on feedback and consultation received from stakeholders. The LARP outlines management frameworks for protecting, monitoring, evaluating and reporting air, surface water and groundwater quality by setting strict environmental limits. In addition, conservation areas will increase by approximately 16% to a total of 22% of the region's land base. Based on a preliminary assessment, the proposed new conservation areas do not appear to affect Harvest. The LARP is currently awaiting approval by the legislature.

British Columbia

The Province of British Columbia intends to reduce its GHG emissions to 33% below 2007 levels by 2020 and has set interim targets of 6% below 2007 levels by 2012 and 18% below 2007 levels by 2016 and, accordingly, has implemented the Greenhouse Gas Reduction Targets Act. The Crown is obligated to report every second year on the amount of reductions achieved in the province, although there is no mechanism in place to measure compliance nor is there any consequence for failing to reach the target. A carbon tax was implemented on the purchase or use of fossil fuels within the Province of British Columbia, starting at $10/ton on July 1, 2008 and rising by $5 per year to $30/ton in 2012. Fuel sellers are required to pay a security equal to the tax payable on the final sale to end purchasers and end purchasers are required to pay the tax. Fuel sellers collect carbon tax at the time fuel is sold at retail to the end purchaser. Carbon capture and storage is required for all new coal-fired electricity generation facilities and a 0.4% levy tax has been implemented at the consumer level on electricity, natural gas, grid propane and heating oil that goes towards establishing the Innovative Clean Energy Fund. Harvest has not incurred material compliance costs and does not expect such costs to increase significantly in the future unless the Province of British Columbia introduces new compliance requirements.

Saskatchewan

On May 11, 2009, the Province of Saskatchewan introduced Bill 95, an Act Respecting the Management and Reduction of Greenhouse Gases and Adaptation to Climate Change. The new legislation will establish a provincial plan for reducing GHG emissions to meet provincial targets and promote investments in low-carbon technologies. The Province has indicated that it intends to enter into an equivalency agreement with the federal government to achieve equivalent environmental outcomes under provincial regulation.

On June 22, 2011, the government announced its new Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions from the flaring and venting of associated gas. The standards establish a specified limit for the amount of natural gas that can be flared and vented from an oil well or associated facility. If that limit is exceeded, the producer is required to conserve and store the associated gas for their own use or sale. The standards will come into effect July 1, 2012 for new wells and facilities licensed on or after that date, and July 1, 2015 for existing wells and facilities. Harvest does not anticipate material compliance costs as the Corporation currently has infrastructure in place to conserve gas in most of our operated areas in Saskatchewan.

Newfoundland

The Federal Renewable Fuel Regulations were published in the Canada Gazette, April 10, 2010. At that time an exemption was provided for the addition of ethanol to gasoline sold in Newfoundland and Labrador and on June 20, 2011 a further exemption was provided for the requirements for renewable content in diesel fuel and heating distillate oil sold in Newfoundland and Labrador. These exemptions benefit our Downstream operations by providing relief from the Federal Renewable Fuel Regulations.

In 2011, the Government of Newfoundland and Labrador published its Climate Change Action Plan. The Province, in collaboration with the Conference of New England Governors and Eastern Canadian Premiers, has committed to reduce regional GHG emissions to 1990 levels by 2010, to reduce regional GHG emissions to 10% below 1990 levels by 2020; and to reduce regional GHG emissions to 75-85% below 2001 levels by 2050.

C. Organizational Structure

Harvest is a wholly-owned subsidiary of KNOC. Each of the subsidiary entities identified below is a direct or indirect wholly-owned subsidiary of Harvest Operations.

Harvest Breeze Trust No. 1, a commercial trust
Breeze Trust No. 1 is an unincorporated commercial trust established under the laws of the Province of Alberta on July 8, 2004. Breeze Trust No. 1 is wholly owned by Harvest Operations Corp. and its assets consist of the intangible portion of direct ownership interests in petroleum and natural gas properties purchased from the Breeze Resources Partnership and the Hay River Partnership. Harvest Breeze Trust No. 1 has a 99% interest in each of the Breeze Resources Partnership and the Hay River Partnership.

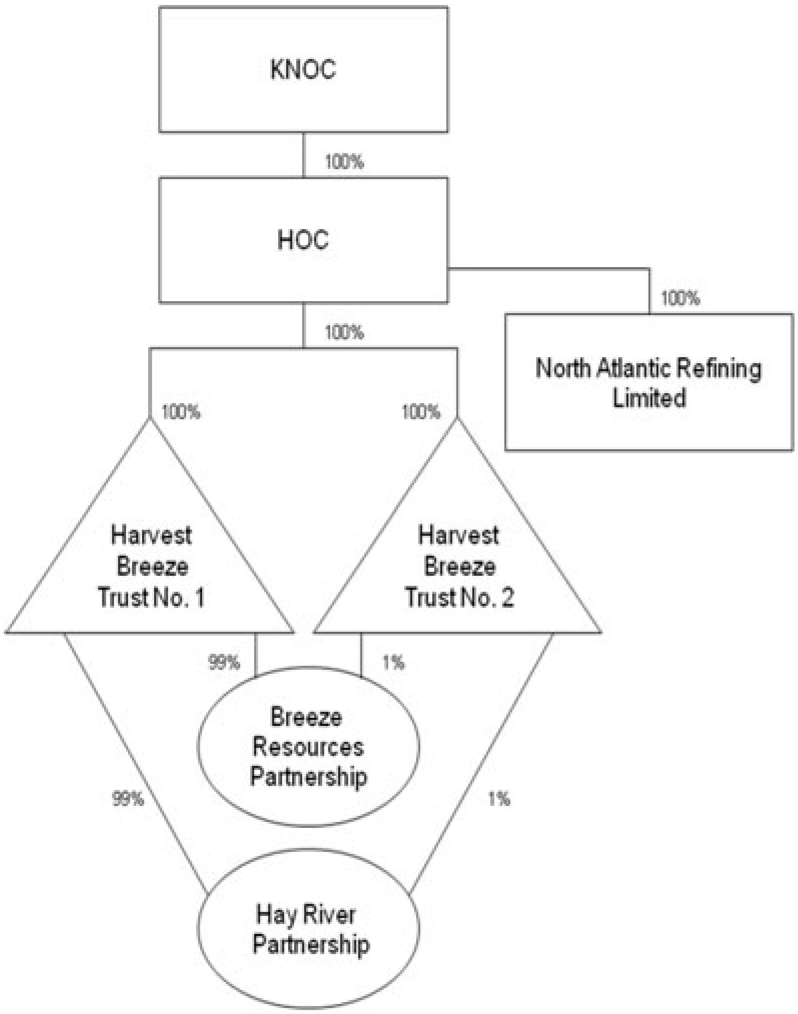
Harvest Breeze Trust. No. 2, a commercial trust
Breeze Trust No. 2 is an unincorporated commercial trust established under the laws of the Province of Alberta on July 8, 2004. Breeze Trust No. 2 is wholly-owned by Harvest Operations Corp. and its assets consist of a 1% interest in each of the Breeze Resources Partnership and the Hay River Partnership.

Breeze Resources Partnership, a general partnership
Breeze Resources Partnership (indirectly wholly owned by the Harvest Operations) is a general partnership formed on June 30, 2004 under the laws of the Province of Alberta. Breeze Resources Partnership was acquired in September 2004. Its assets consist of the tangible portion of direct ownership interest in petroleum and natural gas properties located in east central Alberta and southern Alberta.

Hay River Partnership, a general partnership
Hay River Partnership (indirectly wholly-owned by Harvest Operations) is a general partnership formed on December 20, 2004 under the laws of the Province of Alberta. Hay River Partnership was acquired in August 2005. Its assets consist of the tangible portion of direct ownership interests in petroleum and natural gas properties located in northeastern British Columbia.

North Atlantic Refining Limited, a taxable Canadian corporation
North Atlantic Refining Limited is a wholly owned subsidiary of Harvest Operations. North Atlantic’s assets consist of the Refinery and related retail marketing assets. North Atlantic is responsible for providing the engineering, operations and administrative services related to Harvest's Downstream operations.

The corporate structure including significant subsidiaries is set forth below. Harvest’s remaining subsidiaries and partnerships did not have assets or sales and operating revenues which, in the aggregate, exceeded 20 percent of the total consolidated assets or total consolidated sales and operating revenues of Harvest as at and for the year ended December 31, 2011:



D. Property, Plant and Equipment

UPSTREAM

<u>MATERIAL PROPERTIES</u>

In general, the material properties include major oil accumulations which benefit from active pressure support due to an underlying regional aquifer. Generally, the Properties have predictable decline rates with costs of production and oil price key to determining the economic limits of production. Harvest Operations is actively engaged in cost reduction, production and reserve replacement optimization efforts directed at reserves addition through extending the economic life of these producing properties beyond the limits used by the Independent Reserves Evaluators. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence levels as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

2011 Historical Production by Material Property

	Light, Medium & Heavy Crude Oil	Natural Gas	NGLs	Average Daily Production

Material Property	bbl/d	mcf/d	bbl/d	boe/d
Hay River	4,734	2,985	12	5,243
Red Earth	3,957	72	58	4,027
West Central Alberta	1,959	56,440	3,899	15,265
East Central Alberta	7,598	6,391	205	8,868
Deep Basin	22	18,562	550	3,666
Heavy Oil	7,803	2,196	42	8,211
Saskatchewan Light Oil	3,940	899	30	4,120
Other	3,359	24,815	266	7,761
TOTAL	33,372	112,360	5,062	57,161

Hay River

Hay River was acquired by Harvest on August 2, 2005 and is located approximately 125 miles north west of Grande Prairie in north-eastern British Columbia. In 2011, Hay River produced 5,243 boe/d (95% oil) of medium gravity 24^{o} API crude oil and natural gas from the BlueSky Formation located at a depth of approximately 350 metres. Produced emulsion is processed at the central emulsion processing facility with the clean oil transported via pipeline to sales points. Natural gas produced in conjunction with the oil is processed at the central facility and is either re-injected into the reservoir for pressure maintenance or sold through a sales gas pipeline connected to the facility. Hay River is a winter only access area in that drilling operations can only be undertaken when the ground is frozen (typically between late November and late March). The Hay River medium gravity oil production is priced at a discount to the Edmonton Light oil benchmark, contributing to stronger netbacks when compared to other similar gravity crudes. Harvest has a 100% working interest in this operated property. In 2011, Harvest drilled 44 gross wells, including 28 gross producing dual leg horizontal wells and 16 water source and water injection wells, and established new infrastructure with a total capital expenditure of $78 million. Since 2007, Harvest has focused on increasing water injection into the producing BlueSky Formation to improve overall production and recovery of oil from the reservoir. A gas plant constructed in 2007 was commissioned in the spring of 2008 to eliminate flaring at the site and to manage production of associated gas. Connection of commercial power to the site was also completed in 2008 which allowed for optimization of the production in the field. In 2011, Harvest drilled its first Gething Source well that will improve reservoir management practices.

Red Earth

Red Earth is located 300 miles north west of Edmonton, Alberta. Production in 2011 from Red Earth averaged 4,027 boe/d (99% oil) with an average oil quality of 37° to 39° API from the Slave Point, Granite Wash and Gilwood Formations. Harvest increased its working interest in this area to over 90% following the acquisition of the remaining 40% interest in the Redearth Partnership in the fall of 2010 and has been actively adding to its land base through Crown land sales. In 2011, Harvest drilled 38 gross wells with total capital expenditures, including roads and pipelines, of $110 million. A majority of the drilling was made up of horizontal wells in the Slave Point Formation using multi-staged fractured completions. Future development at Red Earth may include downspace drilling in the Slave Point Formation, application of horizontal well technology as well as potential water injection to increase the recovery factor in a number of smaller Slave Point pools by offsetting production decline. Harvest has an extensive seismic database in the Red Earth area that was instrumental in the discovery of new Gilwood and Granite Wash oil pools in the area and placement of Slave Point horizontal wells.

West Central Alberta

West Central Alberta is comprised of properties west of Highway 2, south of Edmonton and north of Calgary. This is primarily a liquids rich natural gas producing area for the Corporation with some oil production. Properties for this area were added through acquisition over the last several years with the most recent being Hunt in 2011. Production for 2011 for the area is 15,265 boe/d (62% gas). Major properties in this area include Caroline (Beaverhill Lake liquids rich 50% H_2S gas), Crossfield (Ellerslie oil and Basal Quartz), Markerville (Pekisko, Edmonton Sands, Cardium and Glauconite and Ellerslie) and Rimbey (Glauconite, Ostracod, Notikewin and

Cardium). All new liquids rich gas production and oil production are from stage stimulated horizontal wells except for a highly prolific vertical gas play in the Glauconite. In 2011, Harvest participated in 43 gross wells for a total capital expenditure $107 million.

East Central Alberta
This area mainly encompasses legacy oil properties from the Saskatchewan/Alberta border to Alberta Highway 2 and properties south of the city of Edmonton. Working interest in these properties is over 90%. In 2011, the average production was 8,868 boe/d (88% oil) and is primarily oil from 18º to 32º API. The Corporation's largest polymer flood in Wainwright is in this group along with large legacy properties such as Bellshill, Provost and Bashaw. This area is largely a focus of EOR and optimization of current wells and facilities. In 2011, the Corporation participated in 3 gross wells for a total capital expenditure of $3.5 million.

Deep Basin
The Deep Basin is a new area to the Corporation in 2011 and was acquired from Hunt. Deep Basin is located to the south of the city of Grande Prairie in northwest Alberta. Production for 2011 was 3,666 boe/d (84% gas). Legacy production is from vertical wells completed in multiple zones (Falher, Cardium, Cadotte, Cadomin, BlueSky, Dunvegan, and Gething) and comingled together. Recent activity has been focused on drilling high rate 5 to 15 mcf/d stage stimulated horizontal wells in the Falher Formation, which has liquids content between 50 and 100 barrels per mcf. In 2011, Harvest participated in 5 gross wells for a net cost of $27 million.

Heavy Oil
Harvest has various working interests in this area, which is located near the town of Lloydminster on both the Alberta and Saskatchewan side of the border and down into Southern Alberta near the city of Medicine Hat. Major properties in this group include Suffield (Glauconite), Maidstone (Sparky and Waseca), Lloyd (Lloydminster), and Hayter (Dina/Cummings and Sparky). Production is 12° to 15° API heavy crude oil from Cretaceous aged sandstone Formations within the Mannville group. Production averaged 8,211 boe/d (96% oil) in 2011. Harvest drilled 42 gross wells in 2011 with total net capital expenditures of $41.2 million. The majority of the wells drilled were horizontal in the Lloydminster Formation or the Glauconite. Production from the area's wells is processed at a central processing facility with solution gas conservation and then trucked to third party sales points, except for Hayter and Suffield which are pipeline connected. Future plans include downspacing pools with additional horizontal wells and assessing the potential impact of water injection for pressure maintenance and enhanced recovery. This area also contains EOR potential. By increasing injection and using chemical enhancements such as polymers, Harvest believes the ultimate recovery of oil will be increased. Pool optimization and EOR projects will target increased water injection into under-injected reservoirs that have not received adequate pressure maintenance as well as the expansion of the existing Suffield polymer flood to further enhance sweep efficiencies.

Saskatchewan Light Oil
This area includes Harvest's assets in south eastern Saskatchewan towards the Manitoba border as well as production near the City of Kindersley in western Saskatchewan, near the Alberta border. The Kindersley assets are produced from staged fractured horizontal wells in the Viking Formation. The SE Saskatchewan properties are located approximately 110 miles southeast of Regina with production from the non-stage stimulated horizontal wells in Tilston and Souris Valley Formations of Mississippian age. Both of these properties contain high netback light 34° to 39° API oil. Production in 2011 was 4,120 boe/d (96% oil). In 2011, Harvest participated in 43 gross wells with a total net capital expenditure of $64 million.

BlackGold
BlackGold oil sand project is located in north-eastern Alberta near Conklin and is in close proximity to a number of major oil sands developments. The project will utilize SAGD, a proven production technology that uses horizontal drilling and thermal stimulation to maximize energy efficiency and minimize land disturbance. In 2011, Harvest completed the drilling of 12 observation wells and continued to progress on the construction of the central

processing facility and well pads. Since the fourth quarter of 2011, the Corporation has been engaging in an active drilling program under which the drilling of 30 wells (15 SAGD well pairs) are expected to be completed by the end of 2012. During the first quarter of 2012, Harvest completed drilling surface holes for 20 wells and completed drilling 5 of the 30 SAGD wells. Engineering of the project is now more than 70% complete and the site has been cleared and graded. At March 31, 2012, Harvest invested a total of $153.7 million since project inception. Near-term activities include completion of the detailed engineering work and the commencement of module fabrication. Other 2012 activities include module assembly and facility construction. Approval of phase 2 of the project, which is targeted to increase production capacity to 30,000 bbl/d, is underway and anticipated in 2012. The BlackGold project faces similar cost and schedule pressures as other oil sand projects, including shortage of skilled labour, rising costs, and logistics issues surrounding module transportation; phase 1 production is now expected to start in 2014. As a result of these pressures, Harvest is discussing the EPC contract terms with the contractor and considering options to execute the project and manage cost increases. Harvest expects to fund the future capital expenditures with cash flows from operating activities and draws on the Credit Facility.

2012 CAPITAL EXPENDITURE PLAN

Harvest's expected total capital spending on its oil and natural gas properties for 2012 is expected to be approximately $650 million. Harvest plans to fund future capital expenditures through borrowings from the Credit Facility and cash from operating activities. The primary areas of focus for Harvest's Upstream capital program during 2012 are the following:

- BlackGold – Expenditures of approximately $215 million to fund module assembly, facility construction and an active drilling program in which 30 gross wells (15 SAGD well pairs) are currently underway;
- Hay River – Drill 30 gross producing multi-leg horizontal oil wells and water injection wells as well as upgrading the processing infrastructure and drilling and tying-in source water wells to facilitate better reservoir management for an expenditure of $63 million;
- Red Earth – Drill 19 gross light oil wells and establish pipeline infrastructure for emulsion gathering and EOR upside for a net expenditure of $85 million with up to 18 gross multistage fractured horizontal wells for the Slave Point Formation;
- West Central/Rimbey – Drill 15 gross wells targeting the Cardium oil/gas/NGL stage stimulated horizontal wells, Ellerslie light oil vertical wells and Glauconitic (liquids rich natural gas) stage stimulated horizontal wells for an expenditure of $52 million;
- Kindersley, Saskatchewan – Drill 17 gross multistage fractured horizontal wells and build infrastructure for pressure maintenance into the Viking Formation for a total expenditure of $26 million;
- Deep Basin Area – Drill 8 gross Falher horizontal stage fractured liquids rich natural gas wells plus install debottlenecking infrastructure for a total expenditure of $51 million;
- Southeast Saskatchewan Area – Drill 12 gross horizontal light oil wells into the Souris Valley and Tilston Formations for a total expenditure of $20 million;
- Lloydminster Heavy Oil – Drill 25 gross wells (primarily horizontal wells) into the Lloydminster and Waseca Formations for a total expenditure of $26 million;
- Suffield and Wainwright – Expand and continue to inject polymer into the two existing EOR floods for a total expenditure of $22 million; and
- Various Areas – Expenditures of approximately $33 million to exploration projects which includes drilling, seismic and land purchases and $60 million to pursue production optimization including pump upsizing, facility debottlenecking and zonal recompletion.

Incremental Exploitation and Development Potential

Management of Harvest Operations has identified numerous development opportunities, many of which provide the potential for capital investment and incremental production beyond that identified in the Reserves Report. Opportunities being considered include:

- Implementation or optimization of enhanced water floods beyond the two polymer floods previously mentioned in selected pools such as Suffield, Hay River, Red Earth, Cecil and Kindersley resulting in increased production and recovery;
- Increasing water handling and water disposal capacity at key fields such as Hayter, Suffield and Bellshill Lake to add incremental oil volumes. This includes additional use of free water knock-outs and additional disposal wells;
- De-bottlenecking existing fluid handling facilities and surface infrastructure;
- Uphole completions of bypassed or untested reserves in existing wellbores, including recompletion of existing shut-in wells to access undrained reserves;
- Selected infill and step-out development drilling opportunities for various proven targets generally defined by 3-D seismic;
- Numerous exploratory opportunities defined by seismic from which value might be extracted by sale, Farmout or joint venture;
- Management of dry gas portfolio to shut-in wells currently with low gas netbacks due to falling gas prices to preserve reserves to be produced at a time when gas prices improve; and
- Utilizing multistage fractured technology in horizontal wells to increase oil recovery from tight oil and gas formations at Red Earth (Slave Point Formation), Crossfield (Basal Quartz and Ellerslie Formations), Kindersley (Viking Formation), Deep Basin (Falher Formation) and Rimbey/West Central Area (Cardium, Glauconite, Viking, Ostracod, Notikewin, Wilrich Formations).

DOWNSTREAM

In our Downstream operations the only material asset is the Refinery. While the nameplate capacity is 115,000 bbl/d, the average daily throughput was 66,417 bbl/d for the year ended December 31, 2011 due to planned maintenance of the refinery units. For further discussion, refer to Item 5.A “Operating Results”.

The Corporation has identified de-bottlenecking projects at the Refinery which are anticipated to improve the yield of distillate products, enhance feedstock receiving and storage facilities and improve process heating design and combustion technologies. The anticipated completion date for the final project is 2015 with total estimated expenditures of approximately $245 million to complete all projects (Isomax unit, flare gas recovery unit, and crude storage). The debottlenecking projects began in 2009 and $115 million had been incurred as at December 31, 2011. The project will be funded through cash flows from operations as well as capital available to the Corporation through its capital resources as discussed in Item 5.B of this annual report.

OTHER

For further information on environmental issues that may affect the utilization of the Upstream and Downstream assets, please see Item 3.D “Risk Factors’’ and Item 4.B “Business Overview - Environmental Regulations”. The Corporation’s Credit Facility is secured by a first floating charge over all of the assets (excluding BlackGold assets) of Harvest’s Operating Subsidiaries plus a first mortgage security interest on the Downstream operation’s refinery assets. For further information, please see Item 10.C “Material Contracts”.

ITEM 4A. UNRESOLVED STAFF COMMENTS

None.

ITEM 5. OPERATING AND FINANCIAL REVIEW AND PROSPECTS

The information presented has been prepared in accordance with IFRS and should be read in conjunction with Item 3 “Key Information”, and our consolidated financial statements and related notes for the years ended December 31, 2011 as set out in this annual report under Item 18.

The adoption of IFRS has not led to any significant changes in Harvest's Upstream operating netback, Downstream operating loss and debt covenants ratios. Further information on the IFRS adoption is provided in Notes 2 and 27 of the audited consolidated financial statements for the year ended December 31, 2011, which has been included in this annual report under Item 18.

IFRS 1 allows certain optional exemptions from full retrospective application and other elections on transition. Note 27 in the audited consolidated financial statements for the year ended December 31, 2011 states the exemptions taken by the Corporation. Certain exemptions were made by Harvest based on financial data available to Harvest and to increase comparability with our peer group. Had Harvest not applied the exemptions, there would be an immaterial impact to Harvest's financial condition and results of operations.

A. Operating Results

UPSTREAM OPERATIONS

Summary of Financial and Operating Results

	Year Ended December 31	
(in 000's except where noted)	**2011**	2010
FINANCIAL		
Petroleum and natural gas sales[1]	**$ 1,286,866**	$ 1,007,004
Royalties	**(195,452)**	(154,757)
Revenues	**1,091,414**	852,247
Expenses		
Operating	**350,456**	265,593
Transportation and marketing	**29,626**	9,394
Realized (gains) losses on risk management contracts[2]	**(6,000)**	1,808
Operating netback after hedging[3]	**717,332**	575,452
General and administrative	**60,804**	45,303
Depreciation, depletion and amortization	**535,692**	470,641
Exploration and evaluation	**18,289**	3,300
Impairment of property, plant and equipment	**-**	13,661
Unrealized (gains) losses on risk management contracts[4]	**(746)**	(2,358)
Gains on disposition of property, plant and equipment	**(7,883)**	(741)
	$ 111,176	$ 45,646
Capital asset additions (excluding acquisitions)	**$ 733,380**	$ 403,848
Property and business acquisitions (dispositions), net	**$ 505,355**	$ 175,657
Abandonment and reclamation expenditures	**$ 22,110**	$ 20,257
OPERATING		
Light / medium oil (bbl/d)	**24,380**	24,077
Heavy oil (bbl/d)	**8,992**	9,253
Natural gas liquids (bbl/d)	**5,062**	2,587
Natural gas (mcf/d)	**112,360**	80,881
Total (boe/d)	**57,161**	49,397

(1) Inclusive of the effective portion of Harvest's realized crude oil hedges.
(2) Realized (gains) losses on risk management contracts include the settlement amounts for power derivative contracts and the ineffective portion of realized crude oil hedges.
(3) This is a non-GAAP measure; please refer to "Non-GAAP Measures" in this annual report.
(4) Unrealized (gains) losses on risk management contracts reflect the change in fair value of the power derivative contracts and the ineffective portion of crude oil hedges.

Commodity Price Environment

	Year Ended December 31		
	2011	2010	Change
West Texas Intermediate crude oil (US$/bbl)	**95.12**	79.53	20%
Edmonton light crude oil ($/bbl)	**95.18**	77.58	23%
Bow River blend crude oil ($/bbl)	**78.41**	68.25	15%
AECO natural gas daily ($/mcf)	**3.62**	4.00	(10%)
U.S. / Canadian dollar exchange rate	**1.011**	0.971	4%
Differential Benchmarks			
Bow River blend differential to Edmonton Par ($/bbl)	**16.77**	9.33	80%
Bow River blend differential as a % of Edmonton Par	**17.6%**	12.0%	47%

The average WTI benchmark price for the year ended December 31, 2011 was 20% higher than the same period in 2010. The average Edmonton light crude oil price ("Edmonton Par") increased for the year ended December 31, 2011 due to the higher WTI prices and improvement of the light sweet differential, partially offset by the strengthening of the Canadian dollar on an annual average basis.

The Bow River heavy oil differential relative to Edmonton Par widened during 2011 as compared to 2010. Heavy oil differentials fluctuate based on a combination of factors including the level of heavy oil inventories, pipeline capacity to deliver heavy crude to U.S. markets and the seasonal demand for heavy oil. The Bow River blend crude oil price ("Bow River") increased in 2011 with the higher WTI prices, and was partially offset by the stronger Canadian dollar and wider Bow River differential.

Realized Commodity Prices

	Year Ended December 31		
	2011	2010	Change
Light to medium oil prior to hedging ($/bbl)	**85.67**	71.09	21%
Heavy oil ($/bbl)	**69.71**	59.94	16%
Natural gas liquids ($/bbl)	**67.92**	58.83	15%
Natural gas ($/mcf)	**3.83**	4.21	(9%)
Average realized price prior to hedging ($/boe)(1)	**62.13**	55.85	11%
Light to medium oil after hedging ($/bbl)(2)	**84.61**	71.09	19%
Average realized price after hedging ($boe)(1) (2)	**61.68**	55.85	10%

(1) Inclusive of sulphur revenue.
(2) Inclusive of the realized gains (losses) from crude oil contracts designated as hedges. Foreign exchange swaps and power contracts are excluded from the realized price.

Prior to hedging activities, our realized price for light to medium oil for the year ended December 31, 2011 increased by 21% compared to the same period in 2010. This is consistent with the upward movement in Edmonton Par prices in 2011. In order to manage commodity price volatility effects on cash flow, Harvest has entered into various crude oil fixed-for-floating swaps. The impact of this hedging activity resulted in a decrease of $1.06/bbl (2010 - $nil) for the year ended December 31, 2011. Please see "Cash Flow Risk Management" section of this item for further discussion with respect to Harvest's cash flow risk management program.

Sales Volumes

	Year Ended December 31				
	2011		2010		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)(1)	**24,380**	**43%**	24,077	49%	1%
Heavy oil (bbl/d)	**8,992**	**16%**	9,253	19%	(3%)
Natural gas liquids (bbl/d)	**5,062**	**9%**	2,587	5%	96%
Total liquids (bbl/d)	**38,434**	**68%**	35,917	73%	7%
Natural gas (mcf/d)	**112,360**	**32%**	80,881	27%	39%
Total oil equivalent (boe/d)	**57,161**	**100%**	49,397	100%	16%

(1) Harvest classifies our oil production, except that produced from Hay River, as light to medium and heavy according to NI 51-101 guidance. The oil produced from Hay River has an average API of 24^{o} (medium grade) and is classified as a light to medium oil, notwithstanding that, it benefits from a heavy oil royalty regime and therefore would be classified as heavy oil according to NI 51-101.

Total sales volumes were 57,161 boe/d for the year ended December 31, 2011, an increase of 16% compared to the same period in 2010. The increase was primarily attributable to the acquisition of the Hunt assets at the end of February 2011.

Harvest's year-to-date light/medium oil sales increased by 1% from 2010 to 24,380 bbl/d. The increase reflects a full year of production from assets acquired in the third quarter of 2010 as well as ten months of production from assets acquired from Hunt in 2011. Sales in 2011 were negatively impacted by the Plains Rainbow Pipeline outage, fires at Red Earth and flooding in southeast Saskatchewan during the summer of 2011.

Heavy oil sales decreased by 3% for the year ended December 31, 2011 compared to 2010. The decrease was primarily due to natural declines and minor production interruptions during the first and second quarter of 2011, partially offset by production increases resulting from Harvest's capital program.

For the year ended December 31, 2011, natural gas sales increased by 31,479 mcf/d (39%), compared to 2010. The increase was mainly due to the acquisition of the Hunt assets at the end of February 2011.

Natural gas liquids sales for the year ended December 31, 2011 increased by 96% compared to the same period in 2010. Similar to the increase in natural gas sales volumes, these increases were mainly due to the acquisition of the Hunt assets at the end of February 2011.

Revenues

	Year Ended December 31		
($ 000's)	**2011**	2010	Change
Light / medium oil sales after hedging(1)	**752,898**	624,778	21%
Heavy oil sales	**228,794**	202,445	13%
Natural gas sales	**156,942**	124,226	26%
Natural gas liquids sales	**125,507**	55,385	127%
Other(2)	**22,725**	170	100%
Petroleum and natural gas sales	**1,286,866**	1,007,004	28%
Royalties	**(195,452)**	(154,757)	26%
Revenues	**1,091,414**	852,247	28%

(1) Inclusive of the effective portion of realized gains (losses) from crude oil contracts designated as hedges.
(2) Inclusive of sulphur revenue and miscellaneous income.

Harvest's revenue is subject to changes in sales volumes, commodity prices and currency exchange rates. For the year ended December 31, 2011, total petroleum and natural gas sales increased by $279.9 million. The 28% increase in annual revenues is attributable to the 10% increase in realized prices after hedging activities, the 16% increase in sales volumes and the increase in sulphur revenue from the acquired Hunt assets. Sulphur revenue represented $21.3 million (2010 - $0.2 million) of the total in other revenues for the year ended December 31, 2011.

Royalties
Harvest pays Crown, freehold and overriding royalties to the owners of mineral rights from which production is generated. These royalties vary for each property and product and our Crown royalties are based on a sliding scale dependent on production volumes and commodity prices. The annual royalties as a percentage of gross revenue for 2011 were 15.2%, slightly below the 2010 percentage of 15.4% .

Operating and Transportation Expenses

	Year Ended December 31				
(in 000's except where noted)	**2011**	**$/boe**	2010	$/boe	$/boe Change
Power and purchased energy	**$ 83,092**	**3.98**	$ 59,106	3.28	0.70
Well servicing	**61,592**	**2.95**	50,427	2.80	0.15
Repairs and maintenance	**60,038**	**2.88**	43,720	2.42	0.46
Lease rentals and property tax	**34,728**	**1.66**	30,637	1.70	(0.04)
Labor - internal	**28,137**	**1.35**	22,641	1.26	0.09
Labor - contract	**19,378**	**0.93**	15,966	0.89	0.04
Chemicals	**15,360**	**0.74**	12,981	0.72	0.02
Trucking	**13,261**	**0.64**	9,645	0.53	0.11
Processing and other fees	**22,643**	**1.09**	13,538	0.75	0.34
Other	**12,227**	**0.58**	6,932	0.38	0.20
Total operating expenses	**$ 350,456**	**16.80**	$ 265,593	14.73	2.07
Transportation and marketing	**$ 29,626**	**1.42**	$ 9,394	0.52	0.90

On a year-to-date basis, operating expenses for 2011 totaled $350.5 million, an increase of $84.9 million when compared to 2010, mainly due to acquisition of assets in 2011 and higher power and purchased energy, repairs and maintenance, and well servicing costs. On a per barrel basis, year-to-date operating expenses increased by $2.07/boe (14%) which is mainly attributable to higher power and purchased energy, repairs and maintenance, and processing costs.

	Year Ended December 31		
($/boe)	**2011**	2010	Change
Power and purchased energy costs	**3.98**	3.28	0.70
Realized (gains) losses on electricity risk management contracts	**(0.37)**	0.10	(0.47)
Net power and purchased energy costs	**3.61**	3.38	0.23
Alberta Power Pool electricity price ($/MWh)	**76.65**	50.78	25.87

Power and purchased energy costs, comprised primarily of electric power costs, represented approximately 24% (2010 – 22%) of the total operating expenses for the year ended December 31, 2011. The power and purchased energy costs for the year ended December 31, 2011 totaled $83.1 million, an increase of 41% compared to 2010, mainly attributable to the higher average Alberta electricity price of $76.65/MWh for the year (2010 - $50.78/MWh) .

Transportation and marketing expenses relate primarily to delivery of natural gas to Alberta's natural gas sales hub, the AECO Storage Hub, and the cost of trucking clean crude oil to pipeline receipt points. As a result, the total dollar amount of costs generally fluctuates in relation to our sales volumes. The $0.90/boe or $20.2 million year-to-date increase is mainly due to Harvest incurring higher oil trucking costs at Hay River and Red Earth in response to the outage of the Plains Rainbow Pipeline during the summer of 2011 combined with the 2011 acquisition of assets.

Operating Netback(1)

	Year Ended December 31		
($/boe)	**2011**	2010	$/boe Change
Petroleum and natural gas sales prior to hedging	**62.13**	55.85	6.28
Royalties	**(9.37)**	(8.58)	(0.79)
Operating expenses	**(16.80)**	(14.73)	(2.07)
Transportation expenses	**(1.42)**	(0.52)	(0.90)
Operating netback prior to hedging(1)	**34.54**	32.02	2.52
Hedging gains (losses)(2)	**(0.16)**	(0.10)	(0.06)
Operating netback after hedging(1)	**34.38**	31.92	2.46

(1) This is a non-GAAP measure; please refer to "Non-GAAP Measures" in this annual report.
(2) Hedging gains (losses) include the settlement amounts for crude oil and power contracts.

Harvest's operating netback represents the net amount realized on a per boe basis after deducting directly related costs. On an annual basis, Harvest's 2011 operating netback prior to hedging increased by $2.52/boe or 8% over 2010. The increase is primarily attributable to increases in realized commodity prices, partially offset by increases in royalties, operating expenses and transportation expenses.

General and Administrative ("G&A") Expense

	Year Ended December 31	
	2011	2010
G&A expenses ($ 000's)	**60,804**	45,303
G&A per boe ($/boe)	**2.91**	2.51

For 2011, G&A expenses increased by 34% compared to 2010. The increase in G&A is primarily due to increased salary expense, partially resulting from the acquisition of assets in 2011. Approximately 90% of the G&A expenses are related to salaries and other employee related costs. Harvest does not have a stock option program, however there is a long-term incentive program, which is a cash settled plan that has been included in the G&A expense.

Depletion, Depreciation and Amortization ("DD&A")

	Year Ended December 31	
	2011	2010
DD&A ($ 000's)	**535,692**	470,641
DD&A per boe ($/boe)	**25.68**	26.10

DD&A expenses for year ended December 31, 2011 increased by $65.1 million compared to 2010, mainly due to higher sales volumes.

Capital Asset Additions

	Year Ended December 31	
($ 000's)	**2011**	2010
Drilling and completion	**386,454**	222,964
Well equipment, pipelines and facilities	**195,062**	107,933
Geological and geophysical	**15,694**	12,719
Land and undeveloped lease rentals	**17,959**	23,388
Corporate	**2,218**	1,935
Other	**14,753**	13,853
Total additions before BlackGold	**632,140**	382,792
BlackGold oil sands ("BlackGold")		
Drilling and completion	**23,443**	70
Well equipment, pipelines and facilities	**70,146**	18,299
Geological and geophysical	**135**	445
Other	**7,516**	2,242
Total BlackGold additions	**101,240**	21,056
Total additions excluding acquisitions	**733,380**	403,848

During 2011, Harvest drilled a total of 251 gross (214.3 net) wells (2010 – 171 gross; 141.4 net wells) with an overall success ratio of 98%. Of the total wells drilled in 2011, Harvest drilled 180 gross (160.5 net) oil wells, 37 gross (21.0 net) gas wells, 30 gross (29.8 net) service wells and 4 gross (3.0 net) dry and abandoned wells. Capital asset additions, excluding BlackGold oil sands, for the year totaled $632.1 million (2010 - $382.8 million). The increase in additions compared to 2010 is mainly due to a more active drilling program in the Corporation's large resource oil pools as well as drilling on new lands acquired from Hunt in 2011. In addition, Harvest spent approximately $80.2 million to equip and tie-in wells, $8.3 million to build a compressor station in Crossfield and $3.1 million to build a new trucking terminal in the Hay River area.

Harvest also invested in EOR projects using polymer flooding technology during the year with focus in the Wainwright and Suffield areas. Harvest expects the 2012 production to increase in these areas as a result of the polymer injection.

BlackGold oil sands

The BlackGold oil sands project continued to progress through 2011. During the fourth quarter of 2011, Harvest began drilling the surface holes for the first SAGD well pairs which are expected to be finished in early 2012. In 2011, Harvest invested a total of $101.2 million (2010 - $21.1 million) in the BlackGold oil sands project for engineering and procurement and drilling of 12 observation wells as well as the construction of the central processing facility and well pads.

Please refer to Item 4.D "Property, Plant and Equipment – Upstream Material Properties" for discussion of Harvest's drilling activities in 2011 by material properties. For information on significant acquisitions made in 2011, please see Item 4.A "Recent Developments".

Decommissioning Liabilities

Harvest's Upstream decommissioning liabilities at December 31, 2011 were $672.7 million (2010 - $652.6 million) for future remediation, abandonment, and reclamation of Harvest's oil and gas properties. The increase of $20.1

million during 2011 was a result of $38.0 million of liabilities acquired from Hunt, new liabilities of $28.4 million incurred on new drills, accretion of $23.2 million, partially offset by a revision of estimates of $46.6 million and $22.1 million of reclamation and abandonment expenditures. The total decommissioning liabilities are based on management's best estimate of costs to remediate, reclaim, and abandon our wells and facilities. The costs will be incurred over the operating lives of the assets with the majority being at or after the end of reserve life. Please refer to the "Contractual Obligations and Commitments" under Item 5.F for the payments due for each of the next five years and thereafter in respect of our decommissioning liabilities.

Goodwill

Goodwill is recorded when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of that acquired business. At December 31, 2011, Harvest had $404.9 million (2010 - $404.9 million) of goodwill on the balance sheet related to the Upstream segment. The goodwill balance is assessed annually for impairment or more frequently if events or changes in circumstances occur that would reasonably be expected to reduce the fair value of the acquired business to a level below its carrying amount. Management has assessed goodwill for impairment and determined that there is no impairment at December 31, 2011.

DOWNSTREAM OPERATIONS

Summary of Financial and Operational Results

	Year Ended December 31	
(in 000's except where noted)	**2011**	2010
FINANCIAL		
Refined products sales[(1)]	**$ 3,239,455**	$ 3,105,957
Purchased products for processing and resale[(1)]	**3,055,236**	2,893,805
Gross margin (loss)[(2)]	**184,219**	212,152
Expenses		
Operating	**108,400**	109,514
Power and purchased energy	**117,275**	106,126
Marketing	**6,293**	6,366
General and administrative	**1,764**	1,764
Depreciation and amortization	**91,006**	83,091
Operating loss[(2)]	**$ (140,519)**	$ (94,709)
Capital asset additions	**$ 284,244**	$ 71,234
OPERATING		
Feedstock volume (bbl/d)[(3)]	**66,417**	86,142
Yield (% of throughput volume)[(4)]		
Gasoline and related products	**32%**	31%
Ultra low sulphur diesel and jet fuel	**41%**	36%
High sulphur fuel oil	**25%**	31%
Total	**98%**	98%
Average refining gross margin (loss) (US$/bbl)[(5)]	**5.28**	5.13

(1) Refined product sales and purchased products for processing and resale are net of intra-segment sales of $507.8 million for the twelve months ended December 31, 2011 (2010 - $443.6 million), reflecting the refined products produced by the refinery and sold by the marketing division.

(2) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this annual report.

(3) Barrels per day are calculated using total barrels of crude oil feedstock and vacuum gas oil.

(4) Based on production volumes after adjusting for changes in inventory held for resale.
(5) Average refining gross margin is calculated based on per barrel of feedstock throughput.

Refining Benchmark Prices

	Year Ended December 31		
	2011	2010	Change
WTI crude oil (US$/bbl)	**95.12**	79.53	20%
Brent crude oil (US$/bbl)	**110.89**	80.40	38%
Mars premium (discount) (US$/bbl)	**12.39**	(1.40)	985%
RBOB crack spread (US$/bbl)	**23.40**	9.58	144%
Heating Oil crack spread (US$/bbl)	**29.03**	10.50	176%
High Sulphur Fuel Oil premium (discount) (US$/bbl)	**1.75**	(8.96)	120%
U.S. / Canadian dollar exchange rate	**1.011**	0.971	4%

Summary of Gross Margin

	Year Ended December 31					
	2011			2010		
(in 000's except where noted)		**Volumes (000s bbls)**	**(US$/bbl)**		Volumes (000s bbls)	(US$/bbl)
Refinery						
Sales						
Gasoline products	**$ 1,055,020**	**9,309**	**114.58**	$ 985,737	10,838	88.31
Distillates	**1,385,985**	**11,073**	**126.54**	1,251,160	13,188	92.12
High sulphur fuel oil	**628,518**	**6,679**	**95.14**	744,628	10,195	70.92
Total sales	**3,069,523**	**27,061**	**114.68**	2,981,525	34,221	84.60
Feedstock (1)						
Middle Eastern	**2,172,600**	**20,938**	**104.90**	1,713,780	21,456	77.56
Russian	**178,246**	**1,460**	**123.43**	485,884	5,884	80.18
South American	**-**	**-**	**-**	211,318	2,978	68.90
	2,350,846	**22,398**	**106.11**	2,410,982	30,318	77.22
Vacuum Gas Oil ("VGO")	**220,656**	**1,844**	**120.98**	95,519	1,124	82.52
Total feedstock	**2,571,502**	**24,242**	**107.24**	2,506,501	31,442	77.41
Other(2)	**371,463**			308,928		
Total feedstock and other costs	**2,942,965**			2,815,429		
Refinery gross margin(3)	**$ 126,558**		**5.28**	$ 166,096		5.13
Marketing						
Sales	**$ 677,738**			$ 568,001		
Cost of products sold	**620,077**			521,945		
Marketing gross margin(3)	**$ 57,661**			$ 46,056		
Total gross margin(3)	**$ 184,219**			$ 212,152		

(1) Cost of feedstock includes all costs of transporting the crude oil to the refinery in Newfoundland.
(2) Includes inventory adjustments, additives and blendstocks and purchase of product for local sales
(3) This is a non-GAAP measure; please refer to "Non-GAAP Measures" in this annual report.

The daily average throughput rate for the year ended December 31, 2011 is 23% lower than the prior year as a consequence of an extended planned maintenance shutdown in 2011, the pre-start-up and commissioning of the new heat exchangers for the platformer and naphtha hydrotreater units and a reduction in throughput rates in the fourth quarter of 2011 due to declining refining margins.

The Downstream operations' refining gross margin is impacted by several factors including the configuration of the refinery product yields, timing of sales under the SOA, transportation costs, location differentials, quality differentials and variability in throughput volume over a given period of time. Product pricing under the SOA is based primarily on New York Harbour reference prices whereas feedstock costs are determined by crude oil reference prices and feedstock crude quality.

Refinery sales increased by $88.0 million for the year ended December 31, 2011 as compared to the prior year mainly as a result of higher market prices on refined products that have been partially offset by lower sales volumes.

The cost of feedstock for the year ended December 31, 2011 was a US$12.12/bbl premium to the benchmark WTI as compared to a discount of US$2.12/bbl in 2010. The change from a discount to a premium in 2011 is a result of the wide spread between WTI and Brent.

For the year ended December 31, 2011, refinery gross margin decreased by 24% as compared to the prior year mainly as a result of the fourth quarter negative refining margins.

The relatively strong Canadian dollar in 2011 has also reduced the contribution from our refinery operations as compared to the prior year as substantially all of the gross margin, cost of purchased energy and marketing expense are transacted in U.S. dollars.

The gross margin from the marketing operations is comprised of the margin from both the retail and wholesale distribution of gasoline and home heating fuels as well as the revenues from marine services including tugboat revenues, and for 2011, the inclusion of the US$10 million settlement from the business interruption claim relating to the fire in the first quarter of 2010.

Operating Expenses

	Year Ended December 31					
	2011			2010		
($ 000's)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Operating cost	**88,424**	**19,976**	**108,400**	92,655	16,859	109,514
Power and purchased energy	**117,275**	**-**	**117,275**	106,126	-	106,126
	205,699	**19,976**	**225,675**	198,781	16,859	215,640
($/bbl of feedstock throughput)						
Operating cost	**3.65**	**-**	**-**	2.95	-	-
Power and purchased energy	**4.84**	**-**	**-**	3.37	-	-
	8.49	**-**	**-**	6.32	-	-

The refining operating cost per barrel of feedstock throughput increased by 24% for the year ended December 31, 2011 as compared to the same period in the prior year, reflecting lower throughput volumes in 2011. Power and purchased energy, consisting of low sulphur fuel oil ("LSFO") and electricity, is required to provide heat and power to refinery operations. The power and purchased energy cost per barrel of feedstock throughput increased by 44%

from the year ended December 31, 2010. The increase in costs is mainly the result of higher prices in 2011, and is partially offset by lower consumption due to lower feedstock throughput.

Capital Asset Additions

Capital asset additions for the year ended December 31, 2011 totaled $284.2 million (2010 - $71.2 million), relating to various capital improvement projects including $62.6 million (2010 - $38.1 million), for the debottlenecking project. Other additions in 2011 include turnaround costs of $102.4 million, catalyst replacement of $32.2 million, tubing and piping replacement of $26.0 million and other significant capital work completed during the turnaround period.

Depreciation and Amortization Expense

	Year Ended December 31	
($ 000's)	**2011**	2010
Refining	**87,346**	79,615
Marketing	**3,660**	3,476
Total depreciation and amortization	**91,006**	83,091

The process units are amortized over an average useful life of 20 to 30 years and turnaround costs are amortized to the next scheduled turnaround. The increase in refining depreciation in 2011 as compared to 2010 is a consequence of the increased capital and turnaround expenditures completed during the year.

Decommissioning Liabilities

Harvest's Downstream decommissioning liabilities result from our ownership of the refinery and marketing assets. At December 31, 2011, Harvest's Downstream decommissioning liabilities were $14.6 million (2010 - $10.4 million), relating to the reclamation and abandonment of these assets with an expected abandonment date of 2069.

CORPORATE

Cash Flow Risk Management

The Corporation enters into crude oil and foreign exchange contracts to reduce the volatility of cash flows from some of its forecast sales. Harvest designates all of its crude oil derivative contracts and certain foreign exchange contracts as cash flow hedges, which are entered into for periods consistent with the forecast petroleum sales. Harvest also enters into electricity price swap contracts to manage some of its price risk exposures. These swap contracts are not designated as hedges and are entered into for periods consistent with forecast electricity purchases.

Any gains and losses recognized on risk management contracts are generally recorded in net income except for when hedge accounting is applied. When risk management contracts qualify for hedge accounting, the fair value of the hedges is recorded in risk management contracts assets or liabilities. The changes in the fair value are reported in other comprehensive income ("OCI") until the settlement of the contracts, except for the ineffective portion of the changes which is reported in net income. Upon settlement of the contracts, the gains or losses previously reported in OCI are reclassified to net income.

The following is a summary of Harvest's realized and unrealized (gains) losses on risk management contracts:

	Year Ended December 31					
($ 000's)	**2011**			2010		
Contracts not designated as hedges	**Power**	**Currency**	**Total**	Power	Currency	Total
Realized (gains) losses	**(7,730)**	**-**	**(7,730)**	1,808	-	1,808
Unrealized (gains) losses	**1,008**	**-**	**1,008**	(3,060)	-	(3,060)

(Gains) losses recognized in net income	**(6,722)**	**-**	**(6,722)**	(1,252)	-	(1,252)

Contracts designated as hedges	**Crude Oil**	Crude Oil
Realized (gains) losses		
Reclassified from OCI to revenues, net of tax	**7,050**	-
Ineffective portion recognized in net income	**1,730**	-
	8,780	-
Unrealized (gains) losses		
Recognized in OCI, net of tax	**(26,471)**	5,020
Ineffective portion recognized in net income	**(1,754)**	702
	(28,225)	5,722
Net (gains) losses recognized in net income outside of revenues	**(6,746)**	(550)

Financing Costs

	Year Ended December 31	
($ 000's)	**2011**	2010
Bank loan	**7,972**	4,947
Convertible debentures	**49,706**	51,926
Senior notes	**35,657**	20,897
Amortization of deferred finance charges	**881**	750
Interest and other financing charges	**94,216**	78,520
Capitalized interest	**(8,640)**	(397)
	85,576	78,123
Accretion of decommissioning liabilities	**23,551**	22,685
Total finance costs	**109,127**	100,808

Interest and other financing charges for the year ended December 31, 2011, including the amortization of related financing costs, $15.7 million (20%) respectively compared to 2010.

Interest expense on Harvest's bank loan for the twelve months ended December 31, 2011 increased by $3.0 million due to the increase in the amount of loan principal outstanding. The effective interest rate for interest charges on our bank loan for the year ended December 31, 2011 was 3.03% compared to 3.65% in 2010.

Interest expense on senior notes increased by 71% for the year ended December 31, 2011 compared to 2010. The increase is due to the higher principal balance of the $6^{7/8}$% senior notes issued in the fourth quarter of 2010, as compared to the $7^{7/8}$% senior notes that were fully redeemed by the end of 2010.

During the year ended December 31, 2011, interest expense of $8.6 was capitalized to the BlackGold project and the Downstream debottlenecking project (2010 - $0.4 million).

Currency Exchange

Currency exchange gains and losses are attributed to the changes in the value of the Canadian dollar relative to the U.S. dollar on our U.S. dollar denominated $6^{7/8}$% Senior Notes and on any U.S. dollar denominated monetary assets or liabilities. For the year of 2011, Harvest recognized an unrealized foreign exchange loss of $2.6 million (2010 - $1.9 million gain) as a result of the weakening of the Canadian dollar relative to the U.S. dollar from $0.99 Cdn/U.S. at December 31, 2010 to $1.02 Cdn/U.S. at December 31, 2011. Harvest recognized a realized foreign exchange gain of $6.5 million (2010 - $1.5 million gain) for the year ended December 31, 2011 as a result of the settlement of U.S. dollar denominated transactions.

The cumulative translation adjustment recognized in other comprehensive income represents the translation of the Downstream operations' U.S. dollar functional currency financial statements to Canadian dollars. For the year ended December 31, 2011, Downstream operations recognized a net cumulative translation gain of $21.5 million (2010 – loss of $45.9 million). The Canadian dollar relative to the U.S. dollar weakened at December 31, 2011 compared to December 31, 2010, resulting in a net cumulative translation gain for the year of 2011. As Downstream operations' functional currency is denominated in U.S. dollars, the strengthening of the U.S. dollar would result in gains from decommissioning liabilities, pension obligations, accounts payable and other balances that are denominated in Canadian dollars, which partially offset the unrealized losses recognized on the senior notes and Upstream U.S. dollar denominated monetary items.

Deferred Income Taxes

For the year ended December 31, 2011, Harvest recorded a deferred income tax recovery of $29.9 million (2010 – recovery of $65.1 million). Our deferred income tax liability will fluctuate during each accounting period to reflect changes in the temporary differences between the book value and tax basis of assets as well as legislative tax rate changes. Currently, the principal source of our temporary differences is the net book value of the Corporation's property, plant and equipment and the unclaimed tax pools.

OUTLOOK

Harvest actively monitors commodity prices and overall market conditions on an ongoing basis and will continue to manage commodity price volatility through a combination of prudent capital expenditures funded largely through operating cash flows, maintaining a solid balance sheet and hedging commodity prices as appropriate to support our strategy.

Upstream

Harvest's Upstream operations (excluding BlackGold) has a capital budget of approximately $435 million for 2012. Of the Upstream budget, approximately 65% will be allocated to drilling activities. Harvest plans to drill 155 wells in 2012 with the majority of the activity taking place within the first few months of the year in a very active winter drilling program. We will also continue investing in Enhanced Oil Recovery ("EOR") and optimization activities with approximately 15% of the Upstream budget.

Our focus will continue to be on our oil weighted and NGLs rich natural gas assets as our asset base is predominantly large pools of light/medium and heavy crude oils that have significant opportunity for development through drilling or optimization. This is complemented by liquids-rich natural gas opportunities with attractive economics, despite low natural gas prices. We expect production volume from the Upstream operations to average 60,000 boe/d for 2012, weighted approximately 30% percent natural gas and 70% percent crude oil and NGLs.

Cost guidance for 2012 includes royalties at 16% of revenue, general & administrative costs averaging $2.80/boe and operating costs to average approximately $16.50/boe.

Harvest has allocated 2012 capital spending of $215 million for the BlackGold oil sands project. The 2012 activities for the BlackGold team will be module assembly, facility construction and an active drilling program in which 30 wells (15 SAGD well pairs) are currently underway. First oil production of 10,000 bbl/d is expected in 2014 and we anticipate ERCB approval in 2012 for an additional 20,000 bbl/d for phase 2 expansion of the project.

Downstream
Harvest's Downstream operations have a 2012 capital budget of $120 million. Approximately 50% is earmarked for projects involving low cost and simple debottlenecking of existing process units and tanks to enhance distillate yields and improve operating costs, energy efficiency and operating reliability. We have also budgeted approximately 25% for mandatory maintenance projects with the remainder on smaller value-add projects.

Harvest anticipates throughput volume to average 100,000 to 106,000 bbl/d in 2012, with operating costs and purchased energy costs aggregating to approximately $7.00/bbl.

Corporate
Harvest maintains a strong credit rating and healthy balance sheet which includes our convertible debentures, 67/8% senior notes, and extendible revolving credit facility, balanced with KNOC-held equity. Our exposure to interest rate fluctuations will continue to be managed through maintaining a mix of financing that carries both floating and fixed interest rates. We will extend maturities as appropriate when our obligations mature or become eligible for repayment.

At December 31, 2011, Harvest had $734.0 million of principal amount of convertible debentures issued in four series. On October 31, 2012, Harvest's 6.40% convertible debentures (TSX: HTE.DB.D) will mature in the amount of $106.8 million. This series of debentures is currently redeemable at par, as are next year's maturing series of 7.25% debentures. At maturity, Harvest plans to repay the indebtedness through a combination of cash on hand, undrawn amounts from the Credit Facility, debit issuance and capital injection.

While we do not speculate on commodity prices or refining margin, we do enter into risk management contracts from time-to-time to mitigate some portion of our price volatility with the objective of stabilizing our cash flow from operating activities. For the remainder of 2012, we have 4,200 bbl/d of WTI hedges under contract with an average price of US $111.37/bbl.

Future development activities and acquisitions in our Upstream business, as well as the maintenance and optimization program in our Downstream business, will be funded substantially from cash generated by operating activities. Funding of more significant acquisitions and growth initiatives will generally rely on a combination of cash from operating activities, incremental debt and capital injections from KNOC.

Harvest is focused on environmental, health and safety issues both in the Upstream and in the Downstream segments of our business. We use responsible practices to ensure the protection of people and the environment. Safety is at the core of our operations and is of utmost importance as we strive to always protect our people, our neighbors and the environment that we all share. As a result, we continue to show better than industry average performance on many EH&S measures in our businesses.

B. Liquidity and Capital Resources

LIQUIDITY
Harvest manages its cash requirements by optimizing the capital structure of the Corporation and maintaining sufficient liquid financial resources to cost-effectively fund obligations as they come due. The Corporation's liquidity needs are met through the following sources: cash generated from operations, borrowings under the Credit Facility, long-term debt issuances and equity injections by KNOC. Harvest's primary uses of funds are operating expenses, capital expenditures, and interest and principal payments on debt instruments.

Cash flow from operating activities for the year ended December 31, 2011 was $560.5 million, compared to $439.2 million in 2010. For the year ended December 31, 2011, the change in non-cash working capital relating to operating activities was a surplus of $51.1 million (2010 – surplus of $32.3 million), and $22.1 million (2010 - $20.3 million) was incurred in the settlement of decommissioning liabilities. During 2011, Harvest's financing activities provided $848.8 million of cash, including $505.4 million of capital injection from KNOC and $343.3 million of net borrowings from the credit facility. Harvest funded $1,013.2 million of capital additions and net asset acquisition activities in 2011 with cash generated from operating activities and financing activities. The acquisition of the Hunt assets in 2011 was funded primarily by the capital injection from KNOC.

Harvest had a working capital deficiency of $265.6 million as at December 31, 2011, as compared to a $20.3 million deficiency at December 31, 2010. The negative working capital in 2011 was primarily related to the classification of $107.1 million of convertible debentures as current liabilities, the use of the $40 million deposit paid in 2010 for the Hunt assets acquisition, and accrued liabilities relating to capital expenditures during the period, partially offset by increased assets arising from the risk management contracts. The Corporation's working capital is expected to fluctuate from time to time, and will be funded from cash flows from operations and borrowings from the credit facility, as required.

Future development activities and acquisitions in our Upstream business as well as the maintenance program in our Downstream business will likely be funded from cash flow from operating activities, while we will generally rely on funding more significant acquisitions and growth initiatives from some combination of cash flow from operating activities, issuances of incremental debt and capital injections from KNOC. Should incremental debt not be available to us through debt capital markets, our ability to make the necessary expenditures to enhance or expand our assets may be impaired. Harvest's liquidity is closely related to its ability to generate cash from operating activities, which is affected by changes in commodity prices, market demands for petroleum and natural gas products and the operating performances of both our Upstream and Downstream assets. Harvest enters into risk management contracts (refer to the "Cash Flow Risk Management" section in this item) to protect the Corporation from cash flow fluctuations due to commodity price changes.

Through a combination of cash available at December 31, 2011, cash from operating activities and undrawn amounts from the Credit Facility, Harvest will have adequate liquidity to fund future operations, debt repayments and forecasted capital expenditures (excluding any major acquisitions). Harvest's 2012 capital program, excluding acquisitions for Upstream and Downstream, is budgeted to be $770 million. Harvest has the ability to modify our capital program in response to changes in commodity prices, market conditions, and cash flows. Refer to the contractual obligations table in Item 5.F below for Harvest's future commitments including the maturity of our existing debt and our capital commitments. For information on risks associated with Harvest liquidity, refer to Item 3.D Risk Factors.

CAPITAL RESOURCES

The following table summarizes the Corporation's capital structure as at December 31, 2011 and 2010:

(in '000s except where noted)		**December 31, 2011**		December 31, 2010
Debts				
Bank loan[1]	**$**	**358,885**	$	14,000
Convertible debentures, at principal amount		**733,973**		733,973
Senior notes, at principal amount (US$500 million)[2]		**508,500**		497,300
		1,601,358		1,245,273
Shareholder's Equity				
386,078,649 common shares issued at December 31, 2011[3]		**3,453,644**		-
335,535,047 common shares issued at December 31, 2010		**-**		3,016,855
	$	**5,055,002**	$	4,262,128

Financial Ratios[4] [5]		
Secured Debt to Annualized EBITDA[6]	**0.73**	0.06
Total Debt to Annualized EBITDA[7]	**2.72**	2.39
Secured Debt to Total Capitalization[6] [8]	**10%**	1%
Total Debt to Total Capitalization[7] [8]	**36%**	31%

(1) The bank loan net of deferred financing costs is $355.6 million (2010 - $11.4 million).
(2) Principal amount converted at the period end exchange rate.
(3) As at April 27, 2012, the number of common shares issued is 386,078,649.
(4) Calculated based on Harvest's Credit Facility covenant requirements (see note 10 of the December 31, 2011 financial statements).
(5) The financial ratios and their components are non-GAAP measures; please refer to the "Non-GAAP Measures" section of this annual report.
(6) Secured debt includes bank loan of $355.6 million (2010 - $11.4 million), letters of credit of $8.7 million (2010 - $2.5 million), and guarantees of $92.1 million (2010 - $15.1 million) at December 31, 2011.
(7) Total debt includes the secured debt, convertible debentures of $742.1 million (2010 - $745.3 million) and senior notes of $495.7 million (2010 - $482.4 million) at December 31, 2011.
(8) Total capitalization includes total debt and shareholder's equity less equity attributed to BlackGold of $459.9 million at December 31, 2011 and 2010.

The outstanding securities of Harvest consist of the common shares, senior notes and convertible debentures.

The authorized capital consists of an unlimited number of common shares. All of the outstanding common shares are held by KNOC.

The most significant restrictions on dividends which can be paid by Harvest exist under the Credit Facility pursuant to provisions restricting Distributions (as defined thereunder). Distributions include dividends on Harvest shares. Under those restrictions, a dividend can be paid as follows:

1. Debt/EBITDA basis: if the Total Debt to EBITDA Ratio after such dividend will not exceed 2.5:1 (including for the purposes of calculations for the ratio, any debt to fund the dividend);
2. Cash flow basis: if the aggregate amount of that dividend and any other Distributions previously paid is less than the amount of EBITDA in excess of aggregate capital expenditures. The aggregate Distributions and aggregate capital expenditures are calculated with respect to a period including the current and three prior fiscal quarters and EBITDA is calculated for the four most recent fiscal quarters; and
3. Stipulated amount basis: on the basis of an aggregate amount of Distributions since April 29, 2011 not to exceed $100 million.

For the purposes of these calculations, all Distributions by Harvest and restricted subsidiaries are included, and similarly capital expenditures are those of Harvest and restricted subsidiaries.

As of December 31, 2011, the Debt/EBITDA restriction and the cash flow restriction as described above resulted in no amount of allowed dividends payable by Harvest. However, on the stipulated amount basis, Harvest would be permitted to pay dividends up to $100 million, since no Distribution has been made since April 29, 2011.

Bank Loan
As at December 31, 2011, Harvest had $441.1 million of unutilized borrowing capacity under the Credit Facility. The unused borrowing capacity and the option to increase the capacity limit to $1.0 billion provide Harvest the

flexibility to manage fluctuations in its liquidity needs. See Item 10.C for a summary of the terms of the Credit Facility.

Convertible Debentures
At December 31, 2011, Harvest had $734.0 million (2010 - $734.0 million) of principal amount of convertible debentures issued in four series with the earliest maturity date in 2012. As a result of KNOC'S acquisition of Harvest Energy Trust in 2009, the debentures are no longer convertible into units but investors would receive $10.00 for each unit notionally received based on each series conversion rate. Because every series of debentures carry a conversion price that exceeds $10.00 per unit, it is assumed that no investor would exercise their conversion option.

The debentures may be redeemed by Harvest at its option in whole or in part prior to their respective redemption dates. The redemption price for the first redemption period is at a price equal to $1,050 per debenture and at $1,025 per debenture during the second redemption period. After the second redemption period, the debentures are redeemable at par. Any redemption will include accrued and unpaid interest at such time. Please refer to note 12 of the December 31, 2011, audited consolidated financial statements for details of the redemption periods.

The 6.4% series convertible debentures with a face value of $106.8 million will be maturing on October 31, 2012. Harvest plans to repay the debenture holders on maturity date through a combination of cash on hand, incremental borrowing from the credit facility, debt issuance and capital injection.

Senior Notes
On October 4, 2010 Harvest issued the 67/8% Senior Notes, which are governed by the terms and conditions of the Note Indenture; see Item 10.C for a summary of the terms of this indenture. Harvest had $508.5 million (2010 - $497.3 million) of principal amount of senior notes outstanding at December 31, 2011. These notes are guaranteed by all of Harvest's existing and future restricted subsidiaries that guarantee the Credit Facility and future restricted subsidiaries that guarantee certain debt. Prior to maturity, redemptions are permitted in whole or in part, at any time at a redemption price equal to the greater of 100% of the principal amount redeemed and the make-whole redemption premium plus any unpaid interest to the redemption date. Harvest may also redeem all of the notes at any time in the event that certain changes affecting Canadian withholding taxes occur.

C. Research and Development

Not applicable.

D. Trend Information

Harvest continues to be subject to variation in energy commodity prices. Prices for natural gas have declined significantly since the end of 2011 due to increased North American supply and mild winter weather. Harvest has responded, along with other producers, by shutting in some natural gas production with higher operating costs and focusing its capital spending program on oil and liquids-rich gas. The forward markets indicate a gradual increase in natural gas prices over the next several years; actual prices will depend on the usual factors such as weather, demand, supply and several other issues, all of which are beyond Harvest's control. High levels of industry operating activity continue to put upward pressure on operating and capital costs and this trend is expected to continue. Despite low natural gas prices, strong pricing for natural gas liquids and corresponding higher production levels have resulted in some restrictions to processing capacity through third party gas plants. Harvest continues to work with third party gas plant operators but expects some periodic interruption of natural gas and natural gas liquid production over the next few years until new capacity is brought on line. Harvest and third party infrastructure, particularly pipelines, require ongoing maintenance and replacement due to corrosion and age. Harvest will continue to invest capital in these projects to support base production in our more mature fields. In the Downstream segment, product crack spreads have been narrow and refinery margins are expected to remain tight under pressure. Feedstock acquisition costs are high due to global reference benchmark prices, while product prices, particularly gasoline, remain low due to demand destruction and slow demand recovery.

The above trend information is based on assumptions that management believes to be reasonable in the light of the group's operational and financial experience. However, no assurance can be given that the above trends will be realized. You should not rely on past performance as an indicator of future performance. You are urged to read the risks associated with Harvest refer to Item 3.D Risk Factors.

E. Off-Balance Sheet Arrangements

As of December 31, 2011, we have no off-balance sheet arrangements in place.

F. Tabular Disclosure of Contractual Obligations.

Harvest has recurring and ongoing contractual obligations and commitments entered into in the normal course of operations including the purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, and land lease obligations. As at the end of December 31, 2011, Harvest has the following significant contractual commitments:

	Payments Due by Period				
($ 000s)	**1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**
Debt repayments(1)	106,796	390,598	595,464	508,500	1,601,358
Debt interest payments(1)	92,360	139,745	79,182	26,220	337,507
Purchase commitments(2)	207,207	48,409	1,143	-	256,759
Operating leases	9,368	15,267	2,187	564	27,386
Transportation agreements(3)	13,936	22,606	9,680	317	46,539
Feedstock and other purchase commitments(4)	776,092	-	-	-	776,092
Employee benefits(5)	4,534	7,828	4,944	3,837	21,143
Decommissioning liabilities(6)	12,782	58,989	33,805	1,343,584	1,449,160
Total	1,223,075	683,442	726,405	1,883,022	4,515,944

(1) Assumes constant foreign exchange rate.
(2) Relates to drilling commitments, AFE commitments, BlackGold capital commitment and Downstream capital commitments.
(3) Relates to firm transportation commitments.
(4) Includes commitments to purchase refinery crude stock and refined products for resale under the SOA with MEC.
(5) Relates to the expected contributions to employee benefit plans and employee long-term incentive plan payments.
(6) Represents the undiscounted obligation by period.

G. Safe Harbor

See "SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS."

ITEM 6. DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

A. Directors and Senior Management

The names, jurisdiction of residence, present positions and offices with Harvest and principal occupations during the past five years of the directors and executive officers of Harvest Operations as at the date hereof are set out in the table below.

Name and Jurisdiction of Residence	Position with Harvest Operations	Principal Occupation
Dr. Seong-Hoon Kim Seoul, South Korea	Director, Chairman since January 2010.	Dr. Kim is currently a director and the Senior Executive Vice President of KNOC. He has held the position of Executive Vice President for New Ventures & Business Exploration as well as other senior management positions within the New Ventures and Exploration division of KNOC.
William A. Friley Jr. Alberta, Canada	Director from 2006 to 2009 and reappointed in January 2010.	Mr. Friley is the President and Chief Executive Officer of Telluride Oil and Gas Ltd., President of Skyeland Oils Ltd., and Chairman of TimberRock Energy Corporation. He is also a Director of OSUM Oil Sands Corp. and a Director of SilverStar Energy Services and Advanced Flow Technologies Inc. Prior to this he acted as President and Chief Executive Officer of Triumph Energy Corporation (a publicly traded oil and natural gas company). Mr. Friley is a previous Director of Mustang Resources Inc. (a publicly traded oil and natural gas company) and a past Chair of Canadian Association of Petroleum Producers.
J. Richard Harris Alberta, Canada	Director since January, 2010.	Mr. Harris is an independent oil and gas consultant in Calgary, Alberta. He was previously the President of four Canadian publicly traded oil and gas companies and has served on the boards of nine other energy and energy service related companies. He was a member of the Alberta Securities Commission's Oil and Gas Securities Taskforce that led to the completion of National Instrument 51-101 and he served on the Commission's Reserve Advisory Committee until his retirement from the Committee in 2005. Mr. Harris is a member of several industry societies and holds the designations of Professional Geologist in Canada and Certified Petroleum Geologist and Certified Professional Geological Scientist in the United States.
Chang-Seok Jeong Seoul, South Korea	Director since January 2012.	Mr. Jeong became a Board Member of Harvest in January 2012. He is currently Executive Vice President of the America Group at KNOC. Mr. Jeong has 26 years of experience at KNOC and has worked in the Vietnam Office, Asia & Europe Production Department and the Overseas E&P Department as a General Manager & Managing Director. He earned a Bachelor's degree in Petroleum Engineering and Master's degree in Petroleum Engineering, both from Seoul National University.
Chang-Koo Kang Seoul, South Korea	Chief Financial Officer since January 2012; Director since January	Mr. Kang is a corporate financial specialist and currently the Chief Financial Officer at Harvest. Prior thereto, he was the Vice President of KNOC's Finance Management

	2010.	Department. Prior to this, he held the position of Finance Team Senior Manager at KNOC. Mr. Kang has worked on financings for the merger and acquisition of PetroTech Peruana S.A., Peru, Harvest Operations Corp., and Sumble JSC, Kazakhstan. He holds a Bachelor's degree in accounting from Pusan National University and graduated with an MBA from Sogang Business School, Sogang University, Korea.
William D. Robertson Alberta, Canada	Director from 2008 to 2009 and reappointed in January 2010.	Mr. Robertson is a Fellow Chartered Accountant and retired Partner of PricewaterhouseCoopers LLP where he acted as lead oil and gas specialist. He is currently a director of Inter Pipeline Fund and Argent Energy. Mr. Robertson has served on the CIM Petroleum Society Standing Committee on Reserve Definitions, the Alberta Securities Commission Financial Advisory Committee, the working sub-committee of the Alberta Securities Commission Taskforce of Oil and Gas Reporting, and the Council of the Institute of Chartered Accounts of Alberta.

Name and Jurisdiction of Residence	Position with Harvest Operations	Principal Occupation
Brant Sangster Alberta, Calgary	Director since November 2010.	Mr. Sangster is currently a director of Canadian Oil Sands Limited, Inter Pipeline Fund, and Titanium Corporation. Mr. Sangster enjoyed a 25-year career as a senior executive with Petro-Canada, where he was responsible for managing the company's oil sands businesses. Prior to this, Mr. Sangster held various strategic planning and operating positions with Imperial Oil Ltd.
Kang Hyun Shin Seoul, South Korea	Director since November 2010.	Mr. Shin is currently KNOC's Vice President of Petroleum Marketing. Prior to this he acted as the Senior Manager for KNOC’s Legal Team as well as the Senior Manager for the KNOC’s Management Planning Team and the Senior Manager for the Strategic Planning Team. Mr. Shin holds an M.A. of Public Administration from the Graduate School of Public Administration, Seoul National University in South Korea.
Kyungluck Sohn Seoul, South Korea	Director since November 2010; Chief Financial Officer until January 2012.	Mr. Sohn is the Vice President, Finance Management Department at KNOC. He was the Chief Financial Officer of Harvest from February 16, 2010 to January 13, 2012. Mr. Sohn served as a Vice President of KNOC's Finance Management department in 2009, and in the Offshore Rig Operations department from May 2006 to December 2008. Mr. Sohn has also held positions as an Administration Manager with the Ulsan Gas Terminal, as a Financing Manager and Information Manager in the Petroleum Information department and a Marketing

		Manager in the Offshore Rig Operations department. Prior to these roles, he held a senior position in the Procurement department of Hyundai Heavy Industry Co., Ltd for four years. He holds a Business Management degree from the Busan National University in South Korea.
Myunghuhn Yi Alberta, Canada	President & Chief Executive Officer since January 2012; Director since December 2010.	Mr. Yi became President and Chief Executive Officer of Harvest Operations in January 2012 and joined Harvest's Board in November 2010. Prior to joining Harvest, he was the Executive Vice President for the Americas Group, as well as President of ANKOR E&P Holdings Corporation in the USA. Mr. Yi has 23 years of experience at KNOC and has worked in Domestic Continental Shelf Development, the Overseas E&P Department, and the Ulsan Branch of the Petroleum Stockpile Department. He earned a bachelor's degree in Petroleum Engineering at Seoul National University and Master's degree of Petroleum Engineering in Hanyang University.
John E. Zahary Alberta, Canada	Director since 2008; President & Chief Executive Officer until January 2012.	John Zahary, a Professional Engineer with extensive senior management experience in the upstream and integrated oil and natural gas industry, is President and Chief Executive Officer of Sunshine Oil Sands Ltd. From February 3, 2006 to January 20, 2012, he was Harvest's President & Chief Executive Officer. Prior to the merger of Harvest and Viking Energy in February 2006, Mr. Zahary had been President & Chief Executive Officer of Viking since April 2004. Mr. Zahary is a past Director and past President of the Alberta Chamber of Resources, past Governor and Officer of the Canadian Association of Petroleum Producers, and Chairman of the western Canada Rhodes Scholarship Selection Committee as well as other business and volunteer involvements. Mr. Zahary holds a B.Sc. in Mechanical Engineering from the University of Calgary and a M.Phil. in Management from the University of Oxford.
Robert A. Pearce Alberta, Canada	Chief Operating Officer since January 2012; Vice President, Corporate Development September 2011 to January 2012 and Treasurer since September 2011.	Mr. Pearce has over 25 years of varied technical and business experience in the areas of corporate development, general management, debt and equity finance, strategy and planning. Prior to joining Harvest he was the Chief Financial Officer of a junior company developing a new oil sands extraction technology. He was Chief Executive Officer and co-founder of North West Upgrading where he led a team developing an independent upgrader/refiner to service Alberta's growing oil sands sector. He served as Treasurer of PanCanadian Energy, was an energy investment banker for several years, and has held various for profit and not-for- profit director positions. Mr. Pearce has an undergraduate degree in Geological Engineering and an MBA in Finance.

Name and Jurisdiction of Residence	Position with Harvest Operations	Principal Occupation
Brian Kwak Alberta, Canada	Deputy Chief Operating Officer, Upstream and Vice President, Global Technology Research Centre	In December 2012, Mr. Kwak was appointed Deputy Chief Operating Officer, Upstream and Vice President, Global Technology Research Centre. From January 2010 until December 2011 Mr. Kwak was Deputy Chief Operating Officer, Upstream and Vice President, BlackGold of Harvest Operations. From November 2006 to January 2010 he was Manager, Subsurface of KNOC Canada and from August 2005 to November 2006 was Manager, Offshore Drilling Rig of KNOC. Prior to this, he acted as the Deputy Manager, Exploration of Cuulong Joint Operating Company in Vietnam. Mr. Kwak holds a M. Sc and B. Sc Geology.
Jongwoo Kim Alberta, Canada	Chief Strategy Officer & Corporate Secretary	Mr. Kim is the Chief Strategy Officer and Corporate Secretary of Harvest Operations. Prior to this, Mr. Kim was the Vice President, Business Planning and Corporate Secretary at Harvest. Before joining Harvest, he held various positions at KNOC over a 17-year period. His previous role with KNOC was acting as the Merger and Acquisition Team Lead. Mr. Kim holds a Master of Science in Finance graduate degree from the Daniel's College of Business, University of Denver.
Patrick BH An Alberta, Canada	Vice President, BlackGold since December 2011.	Mr. An has over 20 years experience in project management, engineering execution of oil and gas facilities development projects and operations of the oil and gas production assets including interfacing with commercial, sub-surface, operations groups, liaisons with partner and third party operating companies, government regulators and legislative bodies. Prior to joining Harvest he was Senior Manager of Production Assets in the Middle East and CIS from 2009 to 2011 and BlackGold project from 2007 to 2008 in KNOC. He holds a B.Sc. in Mechanical Engineering.
Gary Boukall Alberta, Canada	Vice President, Geosciences	Mr. Boukall is the Vice President, Geosciences of Harvest Operations. From December, 2002 to March, 2007 he held various positions with Harvest Operations including Chief Geologist, Manager of Geology and Manager of Geosciences. Mr. Boukall is a professional Geologist.
Les Hogan Alberta, Canada	Vice President, Land	On December 3, 2007, Mr. Hogan was appointed Vice President, Land of Harvest Operations. From June, 2002 to November, 2007 he held various positions including Vice President Land and Community Affairs at Pioneer Natural Resources Canada.
Phil Reist Alberta, Canada	Vice President, Controller	On March 16, 2007, Mr. Reist was appointed Vice President, Controller of Harvest Operations. From February, 2006 to March, 2007 he was Controller of

		Harvest Operations and from September, 2005 to February 2, 2006 he was Controller of Viking. Prior to this Mr. Reist was Vice President, Controller of Penn West Petroleum Ltd. Mr. Reist is a Chartered Accountant.
James Sheasby Alberta, Canada	Vice President, Engineering	On March 16, 2007 Mr. Sheasby was appointed to Vice President, Engineering of Harvest Operations. From February, 2006 to March, 2007 he was Manager, Engineering of Harvest Operations. Prior to this, he was the Manager, Engineering of Viking and the Vice President, Engineering of Hygait Resources. Mr. Sheasby is a Professional Engineer.
Neil Sinclair Alberta, Canada	Vice President, Operations	On March 16, 2007, Mr. Sinclair was appointed Vice President, Operations of Harvest Operations. From February, 2006 to March 2007 he was Manager, Operations of Harvest Operations and from June, 2004 to February, 2006 he was the Manager, Operations of Viking.

As at December 31, 2011, none of the directors and executive officers of Harvest Operations and their associates and affiliates, directly or indirectly, beneficially owned, controlled or directed any of the outstanding shares of Harvest Operations.

Committees of the Board of Directors

Name of Director	Audit Committee	Upstream Reserves, Safety & Environment Committee	Downstream Operations, Safety & Environment Committee	Compensation and Corporate Governance Committee
Dr. Seong-Hoon				Chair
William A. Friley		x		x
J. Richard Harris	x	Chair		
Chang-Seok Jeong				x
Chang-Koo Kang			x	
William Robertson	Chair			x
Brant Sangster	x		Chair	
Kang Hyun Shin			x	
Kyungluck Sohn				x
Myunghuhn Yi		x	x	
John E. Zahary				

Notes:

- As of January 13, 2012, Mr. Myunghuhn Yi was appointed to the Upstream, Reserves, Safety and Environment Committee, replacing Mr. John Zahary.
- As of January 13, 2012, Mr. Chang-Koo Kang and Mr. Myunghuhn Yi were appointed to the Downstream Operations, Safety and Environment Committee, replacing Mr. Kyungluck Sohn and Mr. John Zahary.

- As of January 13, 2012, Mr. Chang-Seok Jeong and Mr. Kyungluck Sohn were appointed to the Compensation and Corporate Governance Committee, replacing Mr. Myunghuhn Yi and Mr. Chang-Koo Kang.
- As of December 2, 2011, Mr. William Robertson was appointed to the Compensation and Corporate Governance Committee.
- As of January 13, 2012, Chang-Seok Jeong was appointed to the Harvest Board.

B. Compensation

COMPENSATION OF DIRECTORS

The independent directors of Harvest Operations Corp., were paid an annual retainer of $30,000, as well as $1,000 for each board meeting attended and $1,000 for each committee meeting attended. If an independent director attended two meetings on the same date, the independent director received $500 for the second meeting. The committee chairmen were paid $1,500 for each committee meeting attended. Each such director was entitled to reimbursement for expenses incurred in carrying out his duties as director.

The following table sets forth all compensation provided to the independent directors of Harvest Operations for the most recently completed financial year ended December 31, 2011. The non-independent directors received no compensation for carrying out their duties as directors.

Name	Fees Earned ($)
William A. Friley	39,000
J. Richard Harris	46,000
William Robertson	42,500
Brant Sangster	45,000

COMPENSATION OF OFFICERS AND MANAGEMENT

The following table sets forth for the year ended December 31, 2011 information concerning the compensation paid to Harvest's executive officers and senior management. The Chief Executive Officer ("CEO"), Chief Financial Officer ("CFO") and the next three most highly compensated individuals at December 31, 2011 are individually identified while the remainders of individuals disclosed in Item 6.A are shown in aggregate.

Name	Salary ($)	Short-term incentive plans(2) ($)	Long-term incentive plans(5) ($)	All other compensation(3) ($)	Total compensation ($)
John Zahary(1)(4)	418,000	270,000	462,027	68,936	1,218,963
Kyungluck Sohn(4)(6)	154,004	37,440	Nil	113,856	305,299
Neil Sinclair	235,621	60,000	130,594	43,189	469,404
Phil Reist	235,043	60,000	120,253	31,522	446,818
Les Hogan	223,840	55,000	114,521	39,742	433,103
Other(7)	1,556,974	237,307	243,322	545,092	2,582,695

(1) Harvest Operations has entered into employment agreements with Mr. Zahary. Please see the section below entitled "Termination Benefits" for further details.

(2) The above amounts were paid to each individual shortly after the end of the fiscal year.

(3) Includes the employer's contributions to a savings plan (equal to 10% of salary) and other taxable benefits.

(4) Mr. Zahary and Mr. Sohn are directors of Harvest Operations, but did not receive compensation for their

services as directors.

(5) One third of the compensation for the 2011 long-term incentive plan was paid in 2012; one third will be paid in 2013, with the remainder to be paid in 2014.

(6) Mr. Sohn participates in the KNOC employee compensation program, but does not participate in Harvest's incentive programs, as he is a secondee to Harvest Operations from KNOC.

(7) Includes remaining executive officers and senior management included in Item 6.A.

SHORT-TERM INCENTIVE PROGRAM

The methodology for determining awards under the short term incentive program does not exclusively or directly use corporate performance goals and results in setting individual awards, but these (including the metrics applied to the long term incentives determination) are considered along with individual performance, and the determination also depends on the application of subjective judgment.

LONG-TERM INCENTIVE PROGRAM

All employees are eligible to participate in Harvest's long term incentive program, which is designed to reward individual and corporate performance in the form of deferred cash payments. These payments are subject to the achievement of the Corporation's key performance indicators. In the Upstream business, Harvest uses the following metrics as part of the assessment of corporate performance for the purpose of determining long term incentive payments: production volume, finding, development and acquisition costs on a per boe basis, earnings before interest, taxes, depreciation and amortization ("EBITDA"), operating and transportation costs on a per boe basis, and safety (lost time injury frequency). In the Downstream business, Harvest uses the following metrics as part of the assessment of corporate performance for the purposes of determining long term incentive payments: sales volume, EBITDA, non-fuel operating costs on a per boe basis and safety (lost time injury frequency). Amounts were based on these measures being met and the degree to which they were met along with individual performance.

Highlights of the corporate achievement are noted below:

- Delivery of a cash contribution[1] from Upstream operations of $661 million versus $532 million in 2010;
- Investment of $733 million in Upstream capital asset additions plus $505 million in net property and business acquisitions, resulting in net overall additions of more than 214% over 2010;
- Strong production performance despite challenges imposed by third-party pipeline failures;
- Strong health and safety performance in both Upstream and Downstream parts of the business;
- Maintenance and enhancement of Harvest's presence in capital markets including expansion of the Credit Facility; and
- Enhancement of Harvest's corporate presence under the equity ownership of KNOC in the active and competitive market in the Canadian oil and gas industry.

[1] These are non-GAAP measures. Upstream cash contribution is Upstream cash from operating activities of $663 million (2010 - $514 million) less changes in Upstream non-cash working capital of $24 million (2010 - $2 million) and the addition of settlements of decommissioning liabilities of $22 million (2010 - $20 million). Please also refer to "Non-GAAP Measures" section for further details.

C. Board Practices

TERM OF OFFICE

Directors are elected or appointed yearly at the annual meeting and the terms of office of all directors expire at the following annual meeting; see Item 6.A above for the period that each Director has served in their current term of office.

TERMINATION BENEFITS

Harvest had an executive employment agreement with Mr. Zahary (former President and Chief Executive Officer), which terminated in early 2012 with Mr. Zahary's resignation. The agreement provides that, in the event of termination of employment without cause, the executive shall be entitled to receive a cash payment equal to a multiple of the executive's total monthly compensation based on (i) his then annual base salary, (ii) an amount equal to 20% of base salary for loss of benefits and (iii) an amount equal to the average annual bonus payments made in the two prior years (or the last annual bonus or a reasonable estimate thereof if only one bonus year or no bonus year has been completed, as the case may be), plus any amount that the executive may be entitled to receive under any long-term incentive plan of Harvest Operations. The agreed multiple is 15 months of total monthly compensation plus one additional month for each full or partial year of service under the agreement (commencing December 22, 2009) to a maximum of 18 months.

If the employment of any of Mr. Zahary is terminated for cause or in the event of permanent disability (within the meaning of the employment agreement), or if any such executive shall voluntarily resign his employment, the executive shall be entitled to receive payment of any earned but unpaid base salary, but shall not be entitled to receive any bonus, severance or termination pay or other payment for loss of employment.

There are no agreements providing for benefits upon termination of employment/service for any other employees or directors.

AUDIT COMMITTEE

The members of the Audit Committee are J. Richard Harris, Brant Sangster and William D. Robertson. The mandate and terms of reference under which the audit committee operates are as follows:

<u>ROLE AND OBJECTIVE</u>

The Audit Committee (the "Committee") is a committee of the board of directors (the "Board") of Harvest Operations Corp. ("HOC") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information. The primary objectives of the Committee with respect to HOC and its subsidiaries, (hereinafter collectively referred to as "Harvest") are as follows:

1. to assist directors meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Harvest and related matters;

2. to ensure that Harvest complies with all applicable laws, regulations, rules, policies and other requirements of governments, regulatory agencies and stock exchanges relating to financial reporting and disclosure;

3. to enhance that Harvest's accounting functions are performed in accordance with a system of internal controls designed to capture and record properly and accurately all of the financial transactions;

4. to provide better communication between directors and external auditor(s);

5. to enhance the external auditor's independence;

6. to increase the credibility and objectivity of financial reports; including that such reports are accurate within a reasonable level of materiality and present fairly Harvest's financial position and performance in accordance with generally accepted accounting principles consistently applied; and

7. to strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditor(s).

MEMBERSHIP OF COMMITTEE

1. The Committee shall be comprised of at least three (3) directors of Harvest Operations, none of whom are members of management of Harvest Operations and all of whom are "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada) and "independent" (as such term is used in Multilateral Instrument 52-110 – Audit Committees ("MI 52-110") unless the Board shall have determined that the exemption contained in Section 3.6 of MI 52-110 is available and has determined to rely thereon.

2. All of the members of the Committee shall be "financially literate" (as defined in MI 52-110) unless the Board shall determine that an exemption under MI 52-110 from such requirement in respect of any particular member is available and has determined to rely thereon in accordance with the provisions of MI 52-110.

3. Unless otherwise designated by the Board, the members of the Committee shall elect a Chairman from among the members and the Chair shall preside at all meetings of the Committee.

MANDATE AND RESPONSIBILITIES OF COMMITTEE

1. It is the responsibility of the Committee to oversee the work of the external auditor(s), including resolution of disagreements between management and the external auditor(s) regarding financial reporting.

2. It is the responsibility of the Committee to satisfy itself on behalf of the Board with respect to Harvest's Internal Control Systems:
   - identifying, monitoring and mitigating business risks; and
   - ensuring compliance with legal, ethical and regulatory requirements.

3. It is a primary responsibility of the Committee to review the annual and interim financial statements of Harvest and related management's discussion and analysis ("MD&A") prior to their submission to the Board for approval. The process should include but not be limited to:
   - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
   - reviewing accounting treatment of unusual or non-recurring transactions;
   - ascertaining compliance with covenants under loan agreements;
   - reviewing disclosure requirements for commitments and contingencies;
   - reviewing adjustments raised by the external auditor(s), whether or not included in the financial statements;
   - reviewing unresolved differences between management and the external auditor(s); and
   - obtain explanations of significant variances with comparative reporting periods.

4. The Committee is to review the financial statements, prospectuses, MD&A, annual information forms and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval.

The Committee must be satisfied that adequate procedures are in place for the review of Harvest's disclosure of all other financial information and shall periodically access the accuracy of those procedures.

5. With respect to the appointment of external auditor(s) by the Board, the Committee shall:

   - recommend to the Board the external auditor(s) to be nominated;
   - recommend to the Board the terms of engagement of the external auditor(s), including the compensation of the auditor(s) and a confirmation that the external auditor(s) shall report directly to the Committee;
   - on an annual basis, review and discuss with the external auditor(s) all significant relationships such auditor(s) have with the Harvest to determine the auditor(s)' independence;
   - when there is to be a change in auditor(s), review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
   - review and pre-approve any non-audit services to be provided to Harvest by the external auditor(s) and consider the impact on the independence of such auditor(s). The Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member report to the Committee at the next scheduled meeting such pre–approval and the member comply with such other procedures as may be established by the Committee from time to time.

6. Review with external auditor(s) (and internal auditor if one is appointed by Harvest) their assessment of the internal controls of Harvest, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditor(s) their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Harvest and its subsidiaries.

7. The Committee shall review risk management policies and procedures of Harvest (i.e. hedging, litigation and insurance).

8. The Committee shall establish a procedure for:

   - the receipt, retention and treatment of complaints received by Harvest regarding accounting, internal accounting controls or auditing matters; and

   - the confidential, anonymous submission by employees of Harvest of concerns regarding questionable accounting or auditing matters.

9. The Committee shall review and approve Harvest's hiring policies regarding partners and employees and former partners and employees of the present and former external auditor(s) of Harvest.

10. The Committee shall have the authority to investigate any financial activity of Harvest. All employees of Harvest are to cooperate as requested by the Committee.

11. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at the expense of Harvest without any further approval of the Board.

12. The Committee shall review the Committee mandate and subsequent revisions periodically, and recommend to the Board for approval.

MEETINGS AND ADMINISTRATIVE MATTERS

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall not be entitled to a second or casting vote.

2. The Chair shall preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee present shall designate from among the members present the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year and at such other times as the Chair of the Committee may determine necessary. Minutes of all meetings of the Committee shall be taken. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Committee shall meet with the external auditor(s) at least once per year (in connection with the preparation of the year end financial statements) and at such other times as the external auditor(s) and the Committee consider appropriate.

6. Agendas, approved by the Chair, shall be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

7. The Committee may invite such officers, directors and employees of the Corporation as it may see fit from time to time to attend at meetings of the Committee and assist thereat in the discussion and consideration of the matters being considered by the Committee.

8. At the discretion of the Committee, the members of the Committee shall meet in private session (in camera) with the external auditor(s), management and with Committee members as required.

9. Following each meeting, the Committee will report to the Board. Upon request, copies of the materials of such Committee meeting should be provided at the next Board meeting after a meeting is held (these may still be in draft form).

10. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board upon request.

11. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at the expense of Harvest.

12. Any members of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Committee shall hold such office until the Committee is reconstituted by the Board.

13. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Committee Chair.

COMPENSATION COMMITTEE[(1)]

The Compensation and Corporate Governance Committee is comprised of Dr. Seong-Hoon Kim, Kyungluck Sohn, Chang-Seok Jeong, William A. Friley Jr. and William Robertson. The Compensation and Corporate Governance Committee ("Compensation Committee") is responsible to the Harvest Board for reviewing matters relating to the human resource policies, employee retention and short and long-term compensation of the directors, officers and employees of Harvest and its subsidiaries in the context of the budget and business plan of the Corporation. The Compensation Committee, when making such salary, bonus and other incentive determinations, takes into consideration individual salaries, bonuses and benefits paid to executives of other similarly sized Canadian conventional oil and natural gas companies with a view to ensuring that such overall compensation packages are competitive. Such information is obtained from the annual Canadian oil and gas industry salaries and benefits survey prepared by Mercer Human Resource Consulting ("Mercer"), a firm of independent consultants that regularly reviews compensation practices in Canada. In addition, the Compensation Committee reviews the completion of operational metrics, strategic objectives and the financial performance of Harvest compared to a peer group, currently comprised of similarly sized oil and gas companies, to determine what performance level has been achieved.

(1) As of January 2012, Mr. Chang-Seok Jeong and Mr. Kyungluck Sohn were appointed to the Compensation and Corporate Governance Committee, replacing Mr. Myunghuhn Yi and Mr. Chang-Koo Kang.

D. Employees

The number of full-time and part-time employees as at December 31 for each of the past three financial years was as follows:

	Upstream		Downstream	Total
	Corporate	***Field***		
2011	376	149	474	999
2010	286	128	481	895
2009	251	136	531	918

In the Downstream operations approximately 67% of the full-time employees and 97% of the part-time employees are unionized and represented by the United Steel Workers of America in four collective bargaining agreements. North Atlantic has had a history of good relations with its union, which is evidenced by the lack of any work stoppage at the Refinery. One of the collective bargaining agreements expires December 31, 2014, two collective agreements expire March 31, 2015 and the fourth collective agreement expires March 31, 2013.

E. Share Ownership

None of the individuals listed in Item 6.B own shares of Harvest as 100% of the issued and outstanding shares of the Corporation are owned by KNOC.

ITEM 7. MAJOR SHAREHOLDERS AND RELATED PARTY TRANSACTIONS
A. Major Shareholders

KNOC owns 100% of the 386,078,649 issued and outstanding common shares of Harvest at December 31, 2011 (see Item 4.A of this annual report for more information on KNOC); this information remains unchanged as at the date of this annual report. KNOC is a leading international oil and gas exploration and production company wholly owned by the Government of Korea. The Trust Units of the predecessor company, Harvest Energy Trust, were widely held up until the date of the KNOC Acquisition on December 22, 2009.

B. Related Party Transactions

Other than as disclosed in Note 26 of the consolidated financial statements contained in Item 18 of this annual report, there have been no material related party transactions from the commencement of the 2010 fiscal year to the date of this annual report.

C. Interests of Experts

Not applicable.

ITEM 8. FINANCIAL INFORMATION
A. Consolidated Statements and Other Financial Information

FINANCIAL STATEMENTS

See Item 18 “Financial Statements” of this annual report for the audited consolidated financial statements. For information regarding the Corporation’s export sales, please see Item 4.B “Business Overview”.

LEGAL PROCEEDINGS
There are no legal proceedings which the Corporation or any subsidiary of the Corporation is or was a party to, or that any of their property is or was the subject of during the year ended December 31, 2011, nor are there any proceedings known to Harvest to be contemplated, that involve a claim for damages exceeding ten per cent of Harvest’s current assets.

During the year ended December 31, 2011, North Atlantic remained a party to a claim brought by the State of New Hampshire against numerous defendants for an unspecified amount of damages. This claim related to alleged contamination of ground water from the use of the gasoline additive methyl tertiary butyl ether (“MTBE”), *The State of New Hampshire v. Amerada Hess Corp. et al*, Docket No. 03-C-0550 (Merrimack County). The plaintiff also asserted collective and joint liability against all defendants. However, the State of New Hampshire Superior Court recently (March 2, 2012) rendered a favourable decision which granted summary judgment in favour of North Atlantic, dismissing all claims against it because of lack of personal jurisdiction over North Atlantic. The order of the Court became final on expiry of the appeal period since no appeal to the New Hampshire Supreme Court (the sole level of appeal) was filed by the plaintiff. As a result, the claim has been fully dismissed against North Atlantic based on the Superior Court order and judgement. No amounts had been accrued in the consolidated financial statements in respect of this matter and the Trust had received an indemnity from Vitol in respect of this contingent liability under the Purchase and Sale Agreement.

There were no penalties or sanctions imposed against the Corporation or any subsidiary of the Corporation by a court relating to securities legislation or by a securities regulatory authority during the year ended December 31, 2011 or any other penalties or sanctions imposed by a court or regulatory body against the Corporation or any subsidiary of the Corporation that would likely be considered important to a reasonable investor in making an investment decision. No settlement agreements were entered into by the Corporation or any subsidiary of the Corporation with a court relating to securities legislation or with a securities regulatory authority during the year ended December 31, 2011.

DIVIDEND POLICY
The Corporation does not currently distribute dividends.

B. Significant Changes

Except as otherwise disclosed in this annual report, there have been no material changes in our financial position, operations or cash flows since December 31, 2011.

ITEM 9. THE OFFER AND LISTING

Not applicable. The Corporation’s shares are not traded on any exchanges or other regulated markets (only common shares have been issued and all of these are held by the Corporation’s sole shareholder, KNOC).

ITEM 10. ADDITIONAL INFORMATION
A. Share Capital

Not applicable.

B. Memorandum and Articles of Association

Given that the information required under this Item 10.B is primarily the listed matters as they are dealt with by or contained in a corporation's articles and bylaws, the following discussion is not, except to the extent applicable and specifically required under this Item (or as necessary for clarity) intended to compare the provisions of Harvest's bylaws and articles to the provisions of the ABCA. In some areas the Harvest bylaws and articles reflect or repeat the ABCA provisions, and in others, where and to the extent permitted by the ABCA, statutory provisions are added to or varied. Some description of the provisions of the ABCA may be made in the following explanations for context or for completeness to describe the relevant matters where the Articles or Bylaws do not have corresponding provisions. However, in any case where provisions of the ABCA are described, reference should be made to the actual statute for a complete understanding of the applicable law. In addition, in certain cases, the establishment of rights or restrictions under the Harvest articles and bylaws is subject to or restricted by the provisions of the ABCA, and the following does describe those aspects of the ABCA to the extent required for clear disclosure to meet the requirements of this Item 10.B. The Harvest articles and bylaws have been developed to be in compliance with the ABCA requirements.

<u>REGISTRATION AND POWERS</u>

The Corporation is registered under Corporate Access Number 2015335496 and is the result of an amalgamation filed May 1, 2010 under the ABCA. The amalgamating corporations were KNOC Canada Ltd., Harvest Operations Corp. and 12065892 Alberta ULC. Companies incorporated or amalgamated under the ABCA have the capacity and, subject to the ABCA, the rights, powers and privileges of a natural person. Under the ABCA no bylaws are required to confer any particular power on a corporation or its directors, but if there are restrictions in its articles on the business carried on or exercised, the corporation shall not carry on or exercise such business. Harvest has no such restrictions in its articles of amalgamation ("Articles.").There are no stated objects or purposes as would be applicable in a memorandum of association jurisdiction. References to "Bylaws" in the following shall mean the bylaws of Harvest, Bylaw No.1 and Bylaw No. 2.

<u>DIRECTORS</u>

Material contracts: A director who is party to a material contract or proposed material contract (or material transaction) has to disclose the nature and extent of the director's interest therein in accordance with the ABCA. Such director is unable to vote on any resolution to approve such contract except as permitted by the ABCA, but is not excluded in determining the quorum. Certain exceptions to the inability to vote are provided for under the ABCA, and in particular an exception is made for contracts relating primarily to the director's remuneration as a director, officer, employee or agent of the Company or an affiliate. Accordingly, the directors do have power in the absence of an independent forum to vote directors' compensation. The compensation of the directors is decided by the directors unless the board of directors requests approval of compensation from the shareholders, which would be required to be by ordinary resolution (passed by a majority of the votes cast by the shareholders who voted on the resolution, or signed by all the shareholders entitled to vote on that resolution.)

Borrowing powers: There are no limitations created either by the Bylaws or Articles on borrowing powers of Harvest exercisable by the directors.

Retirement or non- retirement: There are no provisions for retirement or non-retirement of directors under an age limit.

Qualifying number of shares: There are no requirements for director share ownership provided under the Articles and Bylaws.

CLASSES OF SHARES AND SHARE RIGHTS

The Articles provide for two classes of shares (common shares and preferred shares), and for the issuance of an unlimited number of common share and the issuance in series of preferred shares, in unlimited number

Common shares

Under the Articles the common shares have the right to vote at all meetings of shareholders, except meetings which have voting restricted to holders of a specified class of shares, and under the ABCA (a provision not varied by the Articles) each share entitles the holder to one vote at a meeting of shareholders. There is no provision under the Bylaws or Articles for directors to stand for reelection at staggered intervals or for cumulative voting. The common shares have the right to receive the remaining property and assets of the Corporation on dissolution, subject to the prior rights and privileges applicable to any other class of shares. With respect to the common shares under the Articles or Bylaws, there are no redemption provisions, sinking fund provisions, provisions imposing liability for further capital calls, or any provision discriminating against any existing or prospective holder of the common shares as a result of such shareholder owning a substantial number of shares.

Preferred shares

The preferred shares may be issued from time to time in one or more series with the number of shares in any such series determined by resolution of the directors prior to such issue. Under the Articles, each issued series of preferred shares shall have the rights, privileges, restrictions and conditions attaching to such series as are approved by resolution of the directors before the issue of such series.

Dividends

The common shares have the right to receive any dividend declared by Harvest subject to prior rights and privileges applicable to any other class of shares. The preferred shares' rights to dividends may be established, as with any other rights, by resolution of directors as described above. Under the ABCA (and expressly included in the Bylaws) there is a solvency test and a liquidity test restricting the declaration and payment of dividends. There is no provision in the Articles or Bylaws for a lapse in dividend entitlement, based on time limits or otherwise.

Rights to change share rights

The necessary action to change the rights of holders of an Alberta corporation's stock is set out under the ABCA. Under the ABCA in order to add, change or remove any rights, privileges, restrictions and conditions applicable to all or any of Harvest's shares, the articles may be amended by special resolution. A special resolution is a resolution passed by a majority of not less than 2/3 of the votes cast by the shareholders who voted in respect of that resolution, or signed by all the shareholders entitled to vote on that resolution. The ability to amend or remove any of the foregoing includes rights to accrued dividends and can apply to shares whether issued or unissued. The Bylaws or Articles do not vary this provision of the ABCA and accordingly conditions for change of rights of Harvest shareholders are not more significant than required by law. Classes or series of shares are entitled to be dealt with in this regard by a vote separately by class or series, subject to the provisions of the ABCA. Articles of amendment must be filed after amendments are adopted by resolution.

MEETINGS

Annual meetings are provided under the Articles to be held in accordance with the requirements of the ABCA, and held at the registered office of the Corporation or elsewhere as determined by the directors. Special meetings may be called at any time and held on the dates and at the locations determined by the directors. Written notice to the shareholders is required (at least 21 days and not more than 50 days in advance of the meeting), including, if applicable details of special business to be transacted and the text of any special resolution to be tabled at the meeting. The notice is to be sent to each shareholder entitled to vote at the meeting, and the shareholders entitled to vote are those who on the record date are registered on the records of the Corporation (or if applicable, the transfer agent). Under the ABCA a written resolution signed by all shareholders entitled to vote on it is as valid as though passed at a meeting and such a resolution satisfies statutory meeting requirements. Accordingly in the case of a sole shareholder corporation, such as Harvest it can be practical to address annual meeting requirements and to deal with the business to be transacted at the annual meeting by written resolutions.

SHARE (SECURITIES) OWNERSHIP
The number of direct or indirect beneficial owners of securities of the Corporation under the Articles is limited to not more than fifty (securities in this context does not include non-convertible debt securities) and any invitation to the public to subscribe for securities is prohibited. With respect to the rights to acquire securities, the Articles provide that directors' approval is required to transfer securities to a person who is not already a security holder. There are no limitations under the Articles and Bylaws on the rights of non-resident shareholders to hold securities or to exercise voting rights on securities which are held nor are there any such limitations pursuant to provisions of the ABCA.

OTHER PROVISIONS
There are no provisions of the Articles or Bylaws that would have the effect of delaying, deferring or preventing a change in control of Harvest and that would operate only with respect to a merger, acquisition or corporate restructuring involving Harvest or any subsidiaries. There are no provisions in the Bylaws governing the ownership threshold above which shareholder ownership must be disclosed. There are no provisions in the Articles or Bylaws governing changes in capital, and accordingly no conditions on changes in capital of Harvest under the Articles or Bylaws.

C. Material Contracts

67/8% SENIOR NOTES AND THE NOTE INDENTURE
The following is a summary of the material attributes and characteristics of the Note Indenture (and references below to "Notes" refer to the 67/8% Senior Notes issued on October 4, 2010).

PAYMENT UPON REDEMPTION
Prior to maturity, the Notes are redeemable at a redemption price equal to 100% of the principal amount of the Notes being redeemed, plus a make-whole redemption premium and accrued and unpaid interest to the redemption date. Harvest may also redeem the Notes at any time in the event that certain changes affecting Canadian withholding taxes occur.

COVENANTS
There are also covenants restricting, among other things, certain transactions for the sale of assets, and the incurrence of additional indebtedness if such issuance would result in an interest coverage ratio, as defined in the Note Indenture, of less than 2.0 to 1. Notwithstanding the interest coverage ratio limitation, the incurrence of additional secured indebtedness may not exceed the greater of $1.0 billion and 15% of total assets as outlined in the limitation on liens covenant. In addition, the covenants under the Note Indenture limit the amount of restricted payments, including dividends to Harvest's shareholders, should the defined leverage ratio be greater than 2.50 to 1.

REGISTRATION RIGHTS
The Notes have not been registered under the U.S. Securities Act of 1933 or the securities laws of any other jurisdiction. Harvest has entered into a Registration Rights Agreement. The Registration Rights Agreement will provide that unless the Exchange Offer would not be permitted by applicable law or Securities and Exchange Commission ("SEC") policy, Harvest Operations and the subsidiary guarantors will:

(1) file an Exchange Offer Registration Statement with the SEC on or prior to 45 days after the filing deadline (the

"Filing Date"), as specified in the SEC's rules and regulations, for Harvest's Form 20-F for the fiscal year ended December 31, 2011;

(2) use their commercially reasonable efforts to have the Exchange Offer Registration Statement declared effective by the SEC on or prior to 105 days after the Filing Date; and

(3) following effectiveness of the Exchange Offer Registration Statement,

   (a) commence the Exchange Offer; and

   (b) issue Exchange Notes in exchange for all Notes tendered prior thereto in the Exchange Offer.

CREDIT FACILITY

The Credit Facility is a secured covenant-based $800 million credit facility with a syndicate of financial institutions and includes an accordion feature that permits the Corporation to increase the size of the facility from $800 million to $1.0 billion without lender consent if the Corporation is able to secure additional capacity from an existing or new lender(s).

Harvest continues to pay a floating interest rate plus a risk premium that changes based on the ratio of the Corporation's drawn amount of debt to earnings before interest, taxes, depletion, amortization and other non-cash items ("EBITDA") as more fully defined below. As a result of two amendments of the agreement for the Credit Facility during 2011, pursuant to amending agreements dated April 29, 2011 and December 16, 2011; the minimum applicable margin under the Credit Facility for LIBOR or BA based loans was decreased to 160 bps, as long as Harvest's drawn amount of Senior Debt to EBITDA ratio remains below or equal to one. In addition, the Credit Facility requires standby fees on undrawn amounts. As at December 31, 2011, $358.9 million was drawn on the Credit Facility plus $8.7 million of letters of credit.

In addition to the standard representations, warrants and covenants commonly contained in a credit facility, the Credit Facility agreement contains the following covenants:

   (a) An aggregate limitation of $25 million on financial assistance and/or capital contributions to parties other than those included in the first floating security interest;

   (b) A limitation to carrying on business in countries that are not members of the Organization for Economic Cooperation and Development;

   (c) A limitation on the payment of distributions to shareholders except for permitted distributions. The bases for permitted distributions include those based on Total Debt to EBITDA ratio not exceeding 2.5:1 after any such distribution or in amounts less than EBITDA minus capital expenditures by Harvest and its restricted subsidiaries; and

   (d) Subject to the following quarterly financial covenants:

      (1) Secured Debt to EBITDA of 3.0 to 1.0 or less;

      (2) Total Debt to EBITDA of 3.5 to 1.0 or less;

      (3) Secured Debt to Capitalization of 50% or less; and

      (4) Total Debt to Capitalization of 55% or less.

Note: in the above, “Secured Debt” includes letters of credit, bank debt and guarantees and “Total Debt” consists of Secured Debt, the Notes and the Debentures.

For purposes of determining the financial covenants, the following terms are defined in the Credit Facility agreement:

(a) EBITDA is the aggregate of the past four quarters Net Earnings plus:

(1) interest and financing charges;

(2) future income tax expense;

(3) depletion, depreciation, amortization and other;

(4) unrealized gains/losses on risk management contracts;

(5) unrealized currency exchange gains/losses; and

(6) other non-cash items.

(b) Capitalization is the aggregate of the amounts drawn under the Credit Facility, the 67/8% Senior Notes, the Debentures and shareholders’ equity (less equity relating to BlackGold), all as reported in Harvest’s consolidated balance sheet in accordance with IFRS.

With respect to these financial covenants, Harvest’s December 31, 2011 financial ratios were as follows:

- Secured Debt to EBITDA of 0.73 to 1.0;
- Total Debt to EBITDA of 2.72 to 1.0;
- Secured Debt to Capitalization of 10%; and
- Total Debt to Capitalization of 36%.

SUPPLY AND OFFTAKE AGREEMENT

SOA (2011)

North Atlantic entered into the SOA (2011) on October 11, 2011 upon the termination of the SOA. The SOA (2011) provides that the ownership of substantially all crude oil and other feedstocks and refined product inventories at the Refinery be retained by MEC and that MEC be granted the exclusive right and obligation to provide crude oil feedstock and other feedstocks for delivery to the Refinery as well as the exclusive right and obligation to purchase virtually all refined products produced by the Refinery for export. The SOA (2011) also provides that MEC will receive a time value of money ("TVM") amount associated with the purchase of crude oil and other feedstocks and sale of refined products as the SOA (2011) requires that MEC retain ownership of the crude oil and other feedstocks until delivered through the inlet flange to the Refinery as well as immediately take title to the refined products as they are delivered by the Refinery through the inlet flange to designated storage tanks. Further, the SOA (2011) provides North Atlantic with the opportunity to share the incremental profits and losses resulting from the sale of products beyond the U.S. east coast markets.

Pursuant to the SOA (2011), North Atlantic, in consultation with MEC, requests a certain slate of crude oil and other feedstocks and MEC is obligated to provide the feedstocks in accordance with the request and the other provisions of the SOA (2011). The SOA (2011) includes a feedstock transfer pricing formula that aggregates the pricing for the feedstocks purchased as correlated to published future contract settlement prices, the cost of transportation from the source of supply to the Refinery and the settlement cost or proceeds for related operational price risk management contracts. The purpose of these operational price risk management contracts is to convert the fixed price of crude oil and other feedstock purchases to floating prices for the period from the purchase date through to the date the refined products are sold to North Atlantic to allow "matching" of feedstock purchases to refined product sales.

The SOA (2011) requires that MEC purchase and lift all refined products produced by the Refinery, except for certain excluded refined products to be marketed by North Atlantic in the local Newfoundland market, and provides a product purchase pricing formula that aggregates a price based on the current Boston and New York City markets, less the costs of transportation, insurance, port fees, inspection charges and similar costs incurred by MEC, plus the TVM component.

The SOA (2011) is an evergreen agreement with an initial one-year term and may be terminated by either party at any time thereafter by providing notice of termination no later than six months prior to the desired termination date, or if the Refinery is sold in an arm's length transaction, upon 30 days notice prior to the desired termination date. Further, the SOA (2011) may be terminated upon the continuation for more than 180 days of a delay in performance due to force majeure but prior to the recommencing of performance. Upon termination of the agreement or the right and obligation to provide feedstocks, North Atlantic has the option to purchase or arrange for another feedstock supplier to purchase the feedstocks and refined product inventories in designated tanks at the prevailing prices as stipulated under the SOA (2011).

D. Exchange Controls

There are no governmental laws, decrees, regulations or legislation of Canada or restrictions under the constating documents of Harvest that affect the import or export of capital or the remittance of dividends, interest or other payments to nonresident security holders.

E. Taxation

Not applicable.

F. Dividends and Paying Agents

Not applicable.

G. Statements by Experts

Not applicable.

H. Documents on Display

Documents concerning the Corporation which are referred to in this annual report may be inspected at Harvest's head office, Suite 2100, 330 - 5th Avenue S.W., Calgary, Alberta T2P 0L4. In addition, all of the SEC filings made electronically by Harvest are available to the public on the SEC website at www.sec.gov.

I. Subsidiary Information

Not applicable.

ITEM 11. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following is quantitative information about market risk for the last two fiscal years ended December 31, 2011. Assumptions and qualitative discussions about market risk for the last two fiscal years ended December 31, 2011 can be found in Note 23(c)(iii) of the Corporation's December 31, 2011 consolidated financial statements included under Item 18. All market risk sensitive instruments are entered into for purposes other than trading.

The following is a summary of Harvest's risk management contracts outstanding at December 31, 2011 and 2010:

Contracts Designated as Hedges

December 31, 2011

Contract Quantity	Type of Contract	Term	Contract Price	Fair Value
4,200 bbls/day	Crude oil price swap	2012	US $111.37/bbl	$ 19,718
US $468/day	Foreign exchange swap	2012	$1.0236 Cdn/US	444
				$ 20,162

December 31, 2010

Contract Quantity	Type of Contract	Term	Contract Price	Fair Value
8,200 bbls/day	Crude oil price swap	2011	US $91.23/bbl	$ 19,718

Contracts not Designated as Hedges

At December 31, 2011, there were no contracts that were not designated as hedges.

December 31, 2010

Contract Quantity	Type of Contract	Term	Contract Price	Fair Value
30 MWh	Electricity price swap contracts	2011	Cdn $46.87	$ 1,007

Harvest's maximum exposure to credit risk relating to financial assets at December 31, 2011 and 2010 is the carrying value of accounts receivable. The table below provides an analysis of Harvest's current and past due but not impaired receivables.

December 31, 2011

		Overdue AR			
	Current AR	< 30 days	> 30 days, < 60 days	> 60 days, < 90 days	> 90 days
Upstream accounts receivable	$ 146,164	$ 1,286	$ 556	$ 1,168	$ 4,000
Downstream accounts receivable	50,660	6,155	1,702	206	355
	$ 196,824	$ 7,441	$ 2,258	$ 1,374	$ 4,355[(1)]

(1) Net of $3.3 million of allowance for doubtful accounts.

December 31, 2010

		Overdue AR			
	Current AR	< 30 days	> 30 days, < 60 days	> 60 days, < 90 days	> 90 days
Upstream accounts	$ 119,853	$ 662	$ 283	$ 824	$ 8,891

receivable					
Downstream accounts receivable	79,340	4,503	845	312	283
	$ 199,193	$ 5,165	$ 1,128	$ 1,136	$ 9,174[1]

(1) Net of $4.1 million of allowance for doubtful accounts.

The following table provides an analysis of Harvest's financial liability maturities based on the remaining terms of its liabilities as at December 31, 2011 and 2010, and includes the related interest charges:

December 31, 2011	≤1 year	>1 year ≤3 years	>3 years ≤5 years	>5 years	Total
Accounts payable and accrued liabilities	$ 464,148	$ –	$ –	$ –	$ 464,148
Bank loan and interest	5,643	11,287	360,756	–	377,686
Convertible debentures and interest	158,554	449,138	243,972	–	851,664
$6^{7/8}$% senior notes and interest	34,959	69,919	69,919	534,720	709,517
Guarantees[1]	47,004	–	–	–	47,004
	$ 710,308	**$ 530,344**	**$ 674,647**	**$ 534,720**	**$ 2,450,019**

(1) Amounts are net of the related payables and receivables to and from counterparties

December 31, 2010	≤1 year	>1 year ≤3 years	>4 years ≤5 years	>5 years	Total
Accounts payable and accrued liabilities	$ 342,006	$ –	$ –	$ –	$ 342,006
Settlement of risk management contracts	7,553	–	–	–	7,553
Bank loan and interest	114	14,600	–	–	14,714
Convertible debentures and interest	52,897	529,120	322,417	–	904,434
$7^{7/8}$% senior notes and interest	34,189	68,379	68,379	557,131	728,078
Total	**$ 436,759**	**$ 612,099**	**$ 390,796**	**$ 557,131**	**$ 1,996,785**

At December 31, 2011, if the U.S. dollar strengthened or weakened by 10% relative to the Canadian dollar, the impact on net income and other comprehensive income due to the translation of monetary financial instruments would be as follows:

	Increase (decrease) in Net Income	Increase (decrease) in Other Comprehensive Income
U.S. Dollar Exchange Rate - 10% increase	$ (19,870)	$ (34,754)
U.S. Dollar Exchange Rate - 10% decrease	$ 19,870	$ 34,754

(1) The sensitivity to net income and other comprehensive income is done independently.

At December 31, 2010, if the U.S. dollar strengthened or weakened by 8% relative to the Canadian dollar, the impact on net income and other comprehensive income due to the translation of monetary financial instruments would be as follows:

		Increase (decrease) in Net Income		Increase (decrease) in Other Comprehensive Income
U.S. Dollar Exchange Rate - 8% increase	$	(34,554)	$	(3,384)
U.S. Dollar Exchange Rate - 8% decrease	$	34,554	$	3,384

(1) The sensitivity to net income and other comprehensive income is done independently.

If the following changes in expected forward prices were applied to the fair value of risk management contracts, the pre-tax impact would be as follows:

December 31, 2011		Increase (decrease) in Net Income		Increase (decrease) in Other Comprehensive Income
Forward price of crude oil – 10% increase	$	(1,020)	$	(18,517)
Forward price of crude oil – 10% decrease	$	621	$	11,390

December 31, 2010		Increase (decrease) in Net Income		Increase (decrease) in Other Comprehensive Income
Forward price of electricity – 75% increase	$	9,993	$	-
Forward price of electricity – 75% decrease	$	(6,755)	$	-
Forward price of crude oil – 10% increase	$	(2,844)	$	(25,058)
Forward price of crude oil – 10% decrease	$	1,336	$	11,490

ITEM 12. DESCRIPTION OF SECURITIES OTHER THAN EQUITY SECURITIES

Not applicable.

ITEM 13. DEFAULTS, DIVIDEND ARREARAGES AND DELINQUENCIES

Not applicable.

ITEM 14. MATERIAL MODIFICATIONS TO THE RIGHTS OF SECURITY HOLDERS AND USE OF PROCEEDS

Not applicable.

ITEM 15. CONTROLS AND PROCEDURES

DISCLOSURE CONTROLS AND PROCEDURES
Under the supervision of the Chief Executive Officer and Chief Financial Officer, the Corporation has evaluated the effectiveness of its disclosure controls and procedures as of December 31, 2011 as defined under the rules adopted by the U.S. Securities and Exchange Commission. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that as of December 31, 2011, the disclosure controls and procedures were effective to ensure that information required to be disclosed by Harvest in reports it files or submits to U.S. securities authorities was recorded, processed, summarized and reported within the time period specified in U.S. securities laws and was accumulated and communicated to management, including its Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures.

INTERNAL CONTROL OVER FINANCIAL REPORTING
Management is responsible for establishing and maintaining internal control over our financial reporting. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes. Management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our internal control over financial reporting as of December 31, 2011. The evaluation was based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2011.

Because of its inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control systems are met.

CHANGES IN CONTROL OVER FINANCIAL REPORTING
In connection with the adoption of IFRS, Harvest established additional internal controls over financial reporting, as necessary, to review and validate the conversion to IFRS and relevant transitional activities including restatement of comparative financial information for 2010 and related disclosures. There were no other significant changes in internal controls over financial reporting for the period ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 16A. AUDIT COMMITTEE FINANCIAL EXPERT

Harvest's board of directors has determined Mr. William D. Robertson is an audit committee financial expert as defined in Item 16A of Form 20-F. Mr. Robertson, a member of the board of directors of Harvest, is independent, within the meaning of the definition of audit committee member independence applicable under the Corporate Governance Standards of the New York Stock Exchange. Refer to Item 6.A for additional information on Mr. Robertson's relevant education and experience.

ITEM 16B. CODE OF ETHICS

Harvest has adopted a Code of Ethics that applies to its principal executive, financial and accounting officers, and other members of senior management. Specifically, this code applies to the Registrant's President and Chief Executive Officer, Chief Financial Officer, and Chief Operating Officer. The Code of Ethics can be found on Harvest's Corporate Governance website at http://www.harvestenergy.ca/corporate-overview/corporate-governance.html. There were no waivers or amendments to the Code of Ethics in 2011.

ITEM 16C. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Ernst & Young LLP, Chartered Accountants ("E&Y") have been appointed auditor of Harvest for the fiscal year 2011. Prior to August 11, 2011, KPMG LLP Chartered Accountants ("KPMG") was the auditor of the Corporation. For more information, please see section "Change in Registrant's Certifying Accountant" under Item 16F of this annual report.

The aggregate fees billed by Harvest's external auditor in the last two fiscal years for audit services are as follows:

For the year ended December 31	KPMG[1] 2011	E&Y[2 2011	**Total 2011**	Total[3] 2010
Audit Fees[4]	337,000	561,500	**898,500**	585,000
Audit-Related Fees[5]	137,000	71,000	**208,000**	375,000
Tax Fees[6]	5,100	41,073	**46,173**	-
All Other Fees[7]	-	795	**795**	-
Total	479,100	674,368	**1,153,468**	960,000

(1) Includes fees billed by KPMG for the fiscal year ended December 31, 2011 up to the appointment of E&Y on August 11, 2011.
(2) Includes fees billed by E&Y for the fiscal year ended December 31, 2011 beginning after the appointment of E&Y on August 11, 2011.
(3) Includes fees billed by KPMG for the fiscal year ended December 31, 2010.
(4) Represents the aggregate fees of the Corporation's auditors for audit services in respect of the financial year.
(5) Represents the aggregate fees billed for assurance and related services by the Corporation's auditors that are related to the performance of audit or review of the Corporation's financial statements and are not included under "Audit Fees" and are primarily composed of services related to the Corporation's interim financial statements and debt offerings in 2010.
(6) Represents the aggregate fees billed for tax compliance, tax advice and tax planning in respect of the financial year.
(7) Represents the aggregate fees billed for products and services provided by the Corporation's auditors other than those services reported under "Audit Fees", "Audit Related Fees" and "Tax Fees".

The Audit Committee must first approve all non-audit or special services performed by any independent accountants. All remuneration provided to the Corporation's auditor and any independent accountants are also approved by the Audit Committee. The Corporation's auditor meets with the Audit Committee, without management present, at least annually and more often at the request of either the Audit Committee or the auditor. The audit committee approved all services included in the table above.

ITEM 16D. EXEMPTIONS FROM THE LISTING STANDARDS FOR AUDIT COMMITTEES

Not applicable.

ITEM 16E. PURCHASE OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PURCHASERS

Not applicable.

ITEM 16F. CHANGE IN REGISTRANT'S CERTIFYING ACCOUNTANT

KPMG LLP, Chartered Accountants ("KPMG") resigned as auditor of the Corporation on August 11, 2011. Ernst & Young LLP, Chartered Accountants ("E&Y") was first appointed as the auditor of the corporation on August 11, 2011 to fill the vacancy resulting from the former auditor's resignation. E&Y was re-appointed on November 1, 2011 for the fiscal year 2011. The resignation of KPMG and the appointment of E&Y were considered and approved by the audit committee of the board of directors of the Corporation and approved by the board of directors of the Corporation.

KPMG did not express any reservation in its auditor's report with respect to the fiscal year 2010 and such report did not contain an adverse opinion or a disclaimer of opinion, and was not qualified or modified as to uncertainty, audit scope, or accounting principles. During the 2010 fiscal year or 2011 fiscal year there were no disagreements with KPMG on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which if not resolved to KPMG's satisfaction, would have caused KPMG to make reference to the subject matter of the disagreement(s) in connection with its report, and there were no reportable events that occurred within the 2010 fiscal year or 2011 fiscal year.

ITEM 16G. CORPORATE GOVERNANCE

Not applicable.

ITEM 16H. MINE SAFETY DISCLOSURE

Not applicable.

ITEM 17. FINANCIAL STATEMENTS

Not applicable.

ITEM 18. FINANCIAL STATEMENTS

See F-pages following Item 19.

ITEM 19. EXHIBITS

1	Harvest's Articles of Amalgamation and Bylaws(1)
2	67/8% Senior Notes Indenture, dated October 4, 2010(2)
4.1	Supply and Offtake Agreement between North Atlantic and Macquarie Energy Canada Ltd. dated October 1, 2011(3) and First Amendment to Supply and Offtake Agreement between North Atlantic and Macquarie Energy Canada Ltd dated December 19, 2011(3)
4.2	Amended and Restated Credit Facility dated April 30, 2010(4)
4.3	First Amending Agreement (Credit Facility) dated December 17, 2010(2)
4.4	Second Amending Agreement (Credit Facility) dated April 29, 2011(2)
4.5	Third Amending Agreement (Credit Facility) dated December 16, 2011(5)
4.6	6 7/8% Senior Notes Indenture, dated October 4, 2010(2)
4.7	Harvest's Articles of Amalgamation and Bylaws incorporated by reference to Item 19.1 of this

	annual report.
8	Refer to Item 4.C "Organization Structure" of this annual report.
12.1	Chief Executive Officer Certification required by Rule 13a-14(a) or 15d-14(a)
12.2	Chief Financial Officer Certification required by Rule 13a-14(a) or 15d-14(a)
13.1	Chief Executive Officer Certification required by Rule 13a-14(b) or 15d-14(b)
13.2	Chief Financial Officer Certification required by Rule 13a-14(b) or 15d-14(b)
15.1	McDaniel's consent and Reserve Evaluation Methodology Report covering letter
15.2	GLJ's consent and Reserve Evaluation Procedure Report covering letter
15.3	KPMG response to Item 16F
99.1	E&Y consent letter
99.2	KPMG consent letter

(1) Incorporated by reference to the 2010 Form 20-F filed on June 29, 2011.

(2) Incorporated by reference to Form 6-K filed on June 20, 2011.

(3) Incorporated by reference to Form 6-K filed on April 16, 2012.

(4) Incorporated by reference to Form 6-K filed on May 17, 2010.

(5) Incorporated by reference to Form 6-K filed on April 2, 2012.

SIGNATURES

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

Harvest Operations Corp.

/s/ Chang-Koo Kang
Chang-Koo Kang
Chief Financial Officer

Dated: April 27, 2012

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MANAGEMENT’S REPORT

In management’s opinion, the accompanying consolidated financial statements of Harvest Operations Corp. (the “Company”) have been prepared within reasonable limits of materiality and in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to February 29, 2012. Management is responsible for the consistency, therewith, of all other financial and operating data presented in Management’s Discussion and Analysis for the year ended December 31, 2011.

To meet our responsibility for reliable and accurate financial statements, management has established and monitors internal controls, which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management’s authorization.

Under the supervision of our Chief Executive Officer and our Chief Financial Officer, we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. We have concluded that as of December 31, 2011, our internal controls over financial reporting were effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The consolidated financial statements have been examined by our auditors, Ernst & Young LLP. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. The Auditors’ Report outlines the scope of their examination and sets forth their opinion on our financial statements.

The Board of Directors is responsible for approving the consolidated financial statements. The Board fulfills its responsibilities related to financial reporting mainly through the Audit Committee. The Audit Committee consists exclusively of independent directors and includes at least one director with financial expertise. The Audit Committee meets regularly with management and the external auditors to discuss reporting and governance issues and ensures each party is discharging its responsibilities. The Audit Committee has reviewed these financial statements with management and the auditors and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Company.

/s/ Myunghuhn Yi	/s/ Chang-Koo Kang
Myunghuhn Yi	Chang-Koo Kang
President and Chief Executive Officer	Chief Financial Officer
Harvest Operations Corp.	Harvest Operations Corp.

Calgary, Alberta
February 29, 2012

KPMG LLP
Chartered Accountants
2700 205 - 5th Avenue SW
Calgary AB T2P 4B9

Telephone (403) 691-8000
Fax (403) 691-8008
Internet www.kpmg.ca

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Harvest Operations Corp.

We have audited the accompanying comparative information of Harvest Operations Corp., which comprise the consolidated statements of financial position as at December 31, 2010 and January 1, 2010, the consolidated statements of comprehensive loss, changes in shareholders' equity and cash flows for the year ended December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information, including Note 27, which explains how the transition from pre-changeover Canadian generally accepted accounting principles to International Financial Reporting Standards as issued by the International Accounting Standards Board affected the entity's reported consolidated financial position, financial performance and cash flows.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the comparative information in these consolidated financial statements present fairly, in all material respects, the consolidated financial positions of Harvest Operations Corp. as at December 31, 2010 and January 1, 2010, and its consolidated financial performance and its consolidated cash flows for the year ended December 31, 2010 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

KPMG

Other matter

The consolidated statement of financial position as at December 31, 2011, the consolidated statements of comprehensive loss, changes in shareholders' equity and cash flows for the year ended December 31, 2011 and notes, comprising a summary of significant accounting policies and other explanatory information, are audited by another auditor who expressed an unmodified opinion on February 29, 2012.

/s/ KPMG LLP
Chartered Accountants

Calgary, Canada
February 29, 2012

INDEPENDENT AUDITORS' REPORT

To the Directors and the Shareholder of Harvest Operations Corp.:

We have audited the accompanying consolidated financial statements of Harvest Operations Corp., which comprise the consolidated statement of financial position as at December 31, 2011, and the consolidated statements of comprehensive loss, changes in shareholder's equity and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Harvest Operations Corp. as at December 31, 2011, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Comparative Information

Without modifying our opinion, we draw attention to Note 27 to the consolidated financial statements which describes that Harvest Operations Corp. adopted International Financial Reporting Standards on January 1, 2011 with a transition date of January 1, 2010. These standards were applied retrospectively by management to the comparative information in these financial statements, including the consolidated statements of financial position as at December 31, 2010 and January 1, 2010, and the consolidated statements of comprehensive loss, changes in shareholder's equity and cash flows for the year ended December 31, 2010, and related disclosures. The financial statements of Harvest Operations Corp. for these periods were audited by another auditor who expressed an unmodified opinion on those statements on February 29, 2012.

/s/ Ernst & Young LLP
Chartered accountants

Calgary, Canada
February 29, 2012

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(thousands of Canadian dollars)	Notes	**December 31, 2011**	December 31, 2010	January 1, 2010
Assets				
Current assets				
Cash and cash equivalents	4	**$ 6,607**	$ 18,906	$ –
Accounts receivable and other	23, 26	**212,252**	213,931	178,662
Inventories	5	**60,952**	75,517	86,819
Prepaid expenses		**18,526**	55,071	15,551
Risk management contracts	23	**20,162**	1,007	–
		318,499	364,432	281,032
Non-current assets				
Long-term deposit	25	**24,925**	30,603	–
Investment tax credits and other		**53,994**	44,339	2,177
Deferred income tax asset	20	–	1,633	–
Exploration and evaluation assets	6	**74,517**	59,554	36,034
Property, plant and equipment	7	**5,400,387**	4,483,236	4,054,619
Other long-term asset		**7,105**	–	–
Goodwill	8	**404,943**	404,943	404,943
		5,965,871	5,024,308	4,497,773
Total assets		**$ 6,284,370**	$ 5,388,740	$ 4,778,805
Liabilities				
Current liabilities				
Bank loan	10, 23	**$ –**	$ –	$ 428,017
Accounts payable and accrued liabilities	26	**464,148**	360,487	205,378
Current portion of convertible debentures	12	**107,146**	–	182,806
Current portion of senior notes	11	–	–	42,921
Current portion of decommissioning liabilities	9	**12,782**	16,672	11,710
Risk management contracts	23	–	7,553	2,052
		584,076	384,712	872,884
Non-current liabilities				
Bank loan	10, 23	**355,575**	11,379	–
Convertible debentures	12	**634,921**	745,257	748,261
Senior notes	11, 23	**495,674**	482,389	222,456
Decommissioning liabilities	9	**674,522**	646,347	555,776
Post-employment benefit obligations	21	**25,958**	20,365	17,453
Deferred credits and other		**5,093**	293	357
Deferred income tax liability	20	**54,907**	81,143	142,105
		2,246,650	1,987,173	1,686,408
Total liabilities		**2,830,726**	2,371,885	2,559,292
Shareholder's equity				
Shareholder's capital	13	**3,860,786**	3,355,350	2,422,688
Deficit		**(388,995)**	(284,338)	(203,175)
Accumulated other comprehensive loss	22	**(18,147)**	(54,157)	–
Total shareholder's equity		**3,453,644**	3,016,855	2,219,513
Total liabilities and shareholder's equity		**$ 6,284,370**	$ 5,388,740	$ 4,778,805

Commitments and contingencies *[Note 25]*
The accompanying notes are an integral part of these consolidated financial statements.

On behalf of the Board of Directors:

/s/ William D. Roberson
William D. Roberson, Director

/s/ J. Richard Harris
J. Richard Harris, Director

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

For the years ended December 31,

(thousands of Canadian dollars)	Notes	**2011**	2010
Petroleum, natural gas, and refined products sales		**$ 4,526,321**	$ 4,112,961
Royalties		**(195,452)**	(154,757)
Revenues	15	**4,330,869**	3,958,204
Expenses			
Purchased products for processing and resale		**3,055,236**	2,893,805
Operating	16	**576,131**	481,233
Transportation and marketing		**35,919**	15,760
General and administrative	16	**62,568**	47,067
Depletion, depreciation and amortization		**626,698**	553,732
Exploration and evaluation	6	**18,289**	3,300
Gains on disposition of property, plant and equipment		**(7,883)**	(741)
Finance costs	17	**109,127**	100,808
Risk management contracts gains	23	**(6,746)**	(550)
Foreign exchange gains	18	**(3,986)**	(3,399)
Impairment on property, plant and equipment	7	**–**	13,661
Loss before income tax		**(134,484)**	(146,472)
Income tax recovery	20	**(29,827)**	(65,309)
Net loss		**(104,657)**	(81,163)
Other comprehensive income (loss)			
Gains (losses) on derivatives designated as cash flow hedges, net of tax	22, 23	**19,421**	(5,020)
Gains (losses) on foreign currency translation	22	**21,480**	(45,920)
Actuarial loss, net of tax	21, 22	**(4,891)**	(3,217)
Comprehensive loss		**$ (68,647)**	$ (135,320)

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

	Shareholder's	Accumulated Other Comprehensive	Total Shareholder's

(thousands of Canadian dollars)	Notes	Capital	Deficit	Loss	Equity
Balance at December 31, 2010		$ 3,355,350	$ (284,338)	$ (54,157)	$ 3,016,855
Issue of share capital for cash	3, 13	505,436	–	–	505,436
Gains on derivatives designated as cash flow hedges, net of tax	22	–	–	19,421	19,421
Gains on foreign currency translation	22	–	–	21,480	21,480
Actuarial loss, net of tax	21, 22	–	–	(4,891)	(4,891)
Net loss		–	(104,657)	–	(104,657)
Balance at December 31, 2011		**$ 3,860,786**	**$ (388,995)**	**$ (18,147)**	**$ 3,453,644**
Balance at January 1, 2010		$ 2,422,688	$ (203,175)	$ –	$ 2,219,513
Issue of share capital for cash	13	932,662	–	–	932,662
Losses on derivatives designated as cash flow hedges, net of tax	22	–	–	(5,020)	(5,020)
Losses on foreign currency translation	22	–	–	(45,920)	(45,920)
Actuarial loss, net of tax	21, 22	–	–	(3,217)	(3,217)
Net loss		–	(81,163)	–	(81,163)
Balance at December 31, 2010		$ 3,355,350	$ (284,338)	$ (54,157)	$ 3,016,855

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31, *(thousands of Canadian dollars)*	Notes	**2011**	2010
Cash provided by (used in)			
Operating Activities			
Net loss for the period		**$ (104,657)**	$ (81,163)
Items not requiring cash			
Depletion, depreciation and amortization		**626,698**	553,732
Accretion of decommissioning liabilities	9, 17	**23,551**	22,685
Unrealized gains on risk management contracts	23	**(746)**	(2,358)
Unrealized (gains) losses on foreign exchange	18	**2,555**	(1,875)
Non-cash interest income		**(652)**	(7,029)
Unsuccessful exploration and evaluation costs	6	**17,757**	2,858
Impairment of property, plant and equipment	7	–	13,661
Gains on disposition of property, plant and equipment		**(7,883)**	(741)
Deferred income tax recovery	20	**(29,880)**	(65,097)
Other non-cash items		**4,795**	(1,093)
Realized foreign exchange gain on senior note redemptions		–	(6,438)
Settlement of decommissioning liabilities	9	**(22,110)**	(20,257)
Change in non-cash working capital	19	**51,061**	32,299
		560,489	439,184
Financing Activities			
Issue of common shares, net of issue costs	3,13	**505,436**	558,493
Bank borrowing (repayments), net		**343,315**	(416,743)
Issue of seniors notes, net of issue costs	11	–	495,935
Redemptions of senior notes	11	–	(256,931)
Redemptions of convertible debentures	12	–	(180,193)

Change in non-cash working capital	19	–	1,952
		848,751	202,513
Investing Activities			
Business acquisitions	3	**(509,829)**	(145,144)
Additions to property, plant and equipment	7	**(966,741)**	(428,085)
Additions to exploration and evaluation	6	**(50,883)**	(46,997)
Additions to other long term assets		**(7,413)**	–
Property dispositions (acquisitions), net		**4,474**	(30,513)
Change in non-cash working capital	19	**108,747**	22,503
		(1,421,645)	(628,236)
Change in cash and cash equivalents		**(12,405)**	13,461
Effect of exchange rate changes on cash and cash equivalents		**106**	5,445
Cash and cash equivalents, beginning of year		**18,906**	–
Cash and cash equivalents, end of year		**$ 6,607**	$ 18,906
Interest paid		**$ 75,858**	$ 66,917
Income tax paid (received), net		**$ 53**	$ (212)

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2011 and December 31, 2010
(amounts in thousands of Canadian dollars unless otherwise indicated)

1. Nature of Operations and Structure of the Company

Harvest Operations Corp. ("Harvest" or the "Company") is an integrated energy company with petroleum and natural gas operations focused on the operation and further development of assets in western Canada ("Upstream") and a medium gravity sour crude hydrocracking refinery and retail and wholesale petroleum marketing business both located in the Province of Newfoundland and Labrador ("Downstream"). Harvest's Downstream business operates under its wholly owned subsidiary, North Atlantic Refining Limited ("North Atlantic").

Harvest is a wholly owned subsidiary of Korea National Oil Corporation ("KNOC"). The Company is incorporated and domiciled in Canada.

These consolidated financial statements were approved and authorized for issue by the Board of Directors on February 29, 2012.

Harvest's principal place of business is located at 2100, 330 – 5th Avenue SW, Calgary, Alberta, Canada T2P 0L4.

2. Basis of Presentation and Significant Accounting Policies

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Prior to January 1, 2011, Harvest reported its consolidated financial statements in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") as set out in the Handbook of the Canadian Institute of Chartered Accountants. Effective January 1, 2011, the Company commenced reporting under IFRS. In these consolidated financial statements, the term "Canadian GAAP" refers to Canadian GAAP before the adoption of IFRS.

Subject to certain transition elections disclosed in note 27, Harvest has consistently applied the same accounting policies in its opening IFRS statement of financial position at January 1, 2010 and throughout all periods presented. Note 27 discloses the impact of the transition to IFRS on the Company's reported financial position, operating results and cash flows, including the nature and effect of significant changes in accounting policies from those used in the Company's consolidated financial statements for the year ended December 31, 2010 reported under Canadian GAAP. Comparative figures for 2010 in these consolidated financial statements have been restated to give effect to these changes.

(a) Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis except for held for trading financial assets and derivative financial instruments, which are measured at fair value.

(b) Functional and Presentation Currency

In these consolidated financial statements, unless otherwise indicated, all dollar amounts are expressed in Canadian dollars, which is the Company's functional currency. All references to U.S. $ are to United States dollars.

(c) Use of Estimates and Judgments

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are outlined below:

(i) Reserves

The provision for depletion and depreciation of Upstream assets is calculated on the unit-of-production method based on proved developed reserves. As well, reserve estimates impact net income through the application of impairment tests. Revisions or changes in the reserve estimates can have either a positive or a negative impact on net income and property, plant and equipment ("PP&E").

The process of estimating reserves is complex and requires significant judgments based on available geological, geophysical, engineering and economic data. In the process of estimating the recoverable oil and natural gas reserves and related future net cash flows, Harvest incorporates many factors and assumptions, such as:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;

- future production rates based on historical performance and expected future operating and investment activities;
- future commodity prices and quality differentials;
- discount rates; and
- future development costs.

On an annual basis, the Company engages qualified, independent reserve evaluators to evaluate Harvest's reserve data.

(ii) Impairment of long-lived assets

Long-lived assets (goodwill, PP&E and exploration and evaluation assets) are aggregated into cash- generating units ("CGUs") based on their ability to generate largely independent cash flows and are used for impairment testing. The determination of the Company's CGUs is subject to significant judgment; product type, internal operational teams, geology and geography were key factors considered when grouping Harvest's oil and gas assets into the CGUs.

PP&E is tested for impairment when indications of impairment exist. PP&E impairment indicators include decreases in commodity prices, production, reserves and operating results, cost overruns and construction delays. E&E impairment indicators include expiration of the right to explore and cessation of exploration in specific areas, lack of potential for commercial viability and technical feasibility and when E&E costs are not expected to be recovered from successful development of an area. The determination of whether such indicators exist requires significant judgment.

The recoverable amounts of CGUs and individual assets are determined based on the higher of value-in-use calculations and estimated fair values less costs to sell. To determine the recoverable amounts, Harvest uses reserve estimates and future commodity prices for the Upstream operations and expected future refining margins and capital spending plans for the Downstream operations. The estimates of future commodity prices, refining margins and discount rates require significant judgments.

(iii) Exploration and evaluation ("E&E") assets

The decision to transfer assets from E&E to PP&E is dependent on the technical feasibility and commercial viability of the related E&E projects. Such decision is subject to management's judgment and use of estimates such as reserves, future commodity prices and discount rates.

(iv) Decommissioning liabilities

In the determination of decommissioning liabilities, management is required to make a significant number of estimates and assumptions with respect to activities that will occur in the future including the ultimate settlement amounts, inflation factors, risk-free discount rates, timing of settlement, emergence of new restoration techniques and expected changes in legal, regulatory, environmental and political environments. The decommissioning liabilities also result in an increase to the carrying cost of the related PP&E. The obligation accretes to a higher amount with the passage of time as it is determined using present values. A change in any one of the assumptions could impact the estimated future obligation and in return, net income and PP&E.

(v) Employee benefits

Harvest's Downstream operations maintains a defined benefit pension plan and provides certain post-retirement health care benefits, which cover the majority of its Downstream employees and their surviving spouses. An independent actuary determines the costs of the Company's employee future benefit programs using certain management assumptions and estimates such as, the expected plan investment performance, salary escalation, retirement ages of employees, expected health care costs, employee turnover, discount rates and return on plan assets. The obligation and expense recorded related to Harvest's employee future benefit plans could increase or decrease if there were to be a change in these estimates.

The Company also maintains a long-term incentive plan which is a performance-based program. As a result, the compensation costs accrued for the plan are subject to the estimation of what the ultimate payout will be and are subject to management's judgment as to whether or not the performance criteria will be met.

(vi) Consideration transferred

Business acquisitions are accounted for using the acquisition method. Under this method, the consideration transferred is allocated to the assets acquired and the liabilities assumed based on the fair values at the time of the acquisition. In determining the fair value of the assets and liabilities, Harvest is often required to make assumptions and estimates, such as reserves, future commodity prices, future refining margins, fair value of undeveloped land, discount rates, decommissioning liabilities and possible outcome of any assumed contingencies. Changes in any of these assumptions would impact amounts assigned to assets and liabilities and goodwill in the consideration transferred allocation and as a result, future net income.

(vii) Risk management contracts

Derivative risk management contracts are valued using valuation techniques with market observable inputs. The most frequently applied valuation techniques include forward pricing and swap models, using present value calculations. The models incorporate various inputs including the credit quality of counterparties, foreign exchange spot and forward rates, interest rate curves and forward rate curves of the underlying commodity. Changes in any of these assumptions would impact fair value of the risk management contracts and as a result, future net income and other comprehensive income. For risk management contracts designated as hedges, changes in the above mentioned assumptions may impact hedge effectiveness assessment and Harvest's ability to continue applying hedge accounting.

(viii) Income taxes

Tax interpretations, regulations and legislation in the various jurisdictions in which Harvest and its subsidiaries operate are subject to change. The Company is also subject to income tax audits and reassessments which may change its provision for income taxes. Therefore, the determination of income taxes is by nature complex, and requires making certain estimates and assumptions.

Harvest recognizes the net deferred tax benefit related to deferred tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred tax assets requires the Company to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize the net deferred tax assets recorded at the reporting date could be impacted.

(ix) Contingencies

Contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

Significant Accounting Policies

(a) Consolidation

These consolidated financial statements include the accounts of Harvest and its subsidiaries. All inter-entity transactions and balances have been eliminated upon consolidation. Subsidiaries are fully consolidated from the date of acquisition, being the date on which Harvest obtains control, and continue to be consolidated until the date that such control ceases. The financial statements of the subsidiaries are prepared for the same reporting period as Harvest, using consistent accounting policies.

Harvest conducts substantially all of its Upstream petroleum and natural gas production activities through jointly controlled assets. The consolidated financial statements reflect only Harvest's proportionate interest in such activities.

(b) Revenue Recognition

Revenues associated with the sale of crude petroleum, natural gas, natural gas liquids and refined products are recognized when title passes to customers and payment has either been received or collection is reasonably certain. Revenues for retail services are recorded when the services are provided. Revenues are measured at the fair value of the consideration received or receivable.

The sales price of residential home heating fuels and automotive gasoline and diesel within the Province of Newfoundland and Labrador is subject to regulation under the Petroleum Products Act. The Petroleum Products Pricing Commissioner sets the maximum wholesale and retail prices that a wholesaler and a retailer may charge and sets the maximum mark-up between the wholesale price to the retailer and the retail price to the consumer. Prices are set biweekly using a price adjustment formula based on an allowable premium with an interruption formula. The full effect of rate regulation is reflected in the product sales revenue.

(c) Inventories

Inventories are carried at the lower of cost or net realizable value. The costs of inventory are determined using the weighted average cost method. The valuation of inventory is reviewed at the end of each month. When the circumstances that previously caused inventories to be written down below cost no longer exist or when there is clear evidence of an increase in net realizable value because of changed economic circumstances, the amount of the write-down is reversed. The reversal is limited to the amount of the original write-down. The costs of parts and supplies inventories are determined under the average cost method.

(d) Property, Plant, and Equipment ("PP&E") and Exploration and Evaluation ("E&E") Assets

(i) Upstream

Exploration and evaluation expenditures

Prior to acquiring the legal rights to explore an area, all costs are charged directly to the statement of comprehensive loss as E&E expense.

Once the legal rights to explore are acquired, all costs directly associated with the E&E are capitalized. E&E costs are those expenditures incurred for identifying, exploring and evaluating new pools in an area where technical feasibility and commercial viability has not yet been determined. These costs include acquisition of land and mineral leases, geological and geophysical costs, decommissioning costs, E&E drilling, sampling, appraisals and directly attributable general and administrative costs. All such costs are subject to technical, commercial and management review to confirm the continued intent to develop. When this is no longer the case, the costs are charged to net income as E&E expense. When technical feasibility and commercial viability are established, the relevant expenditure is transferred to PP&E after impairment is assessed and any resulting impairment loss is recognized.

E&E assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, E&E assets are allocated to CGUs. The impairment of E&E assets, and any eventual reversal thereof, is recognized as E&E expense in the statement of comprehensive loss.

Development and production costs

The Upstream PP&E generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or an area basis (major components). Development costs include property acquisitions, development drilling, completion, gathering and infrastructure, decommissioning costs and transfers of E&E assets.

Major capital maintenance projects are capitalized but general maintenance and repair costs are charged against income. All other expenditures are recognized in net income as incurred. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of PP&E are recognized in net income as incurred.

Depletion, Depreciation and Amortization

Costs accumulated within each major component of PP&E are depleted using the unit-of-production method by reference to the ratio of production in the period to the related proved developed reserves. Costs of major development projects are excluded from the costs subject to depletion until they are available for use.

Corporate and administrative assets are depreciated on a straight-line basis over the individual assets' useful lives.

Disposal of assets

Gains and losses on disposal of an item of PP&E are determined by comparing the proceeds from disposal with the carrying amount of PP&E and are recognized in the period of disposal.

For exchanges that involve only unproven properties, the exchange is accounted for at cost. Exchanges of development and production assets are measured at fair value unless the exchange transaction lacks commercial substance if neither the fair value of the assets given up nor the assets received can be reliably estimated.

(ii) Downstream

PP&E related to the refining assets are recorded at cost. General maintenance and repair costs are expensed as incurred. Major replacements and capital maintenance projects such as turnaround costs are capitalized. Improvements that increase or prolong the service life or capacity of an asset are capitalized. Any gains or losses on disposal of individual assets are recognized in the year of disposal.

Depreciation

When significant parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components). Depreciation of recorded cost less the residual value is provided on a straight-line basis over the estimated useful life of the major components as set out below.

Asset	Period
Refining and production plant:	
Processing equipment	5 – 35 years
Structures	15 – 20 years
Catalysts and turnarounds	2 – 8 years
Tugs	25 years
Vehicles	2 – 7 years
Office and computer equipment	3 – 5 years

(iii) Impairment of Property, Plant and Equipment and Exploration and Evaluation Assets

Harvest assesses, at each reporting date, whether there is an indication that an asset may be impaired. If any indication exists, Harvest estimates the asset's recoverable amount. An asset's recoverable amount is the higher of an asset's fair value less costs to sell and its value-in-use. The recoverable amount is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets. In such case, an impairment test is performed at the CGU level. A CGU is a group of assets that Harvest aggregates based on their ability to generate largely independent cash flows.

Where the carrying amount of an asset or CGU exceeds its recoverable amount, the asset is considered impaired and is written down to its recoverable amount. To determine value-in-use, the Company estimates the present value of the future net cash flows expected to derive from the continued use of the asset or CGU. Discount rates that reflect the market assessments of the time value of money and the risks specific to the asset or CGU are used. In determining fair value less costs to sell, discounted cash flows and recent market transactions are taken into account, if available. These calculations are corroborated by valuation multiples or other available fair value indicators.

Impairment losses are recognized in those expense categories consistent with the function of the impaired asset. Impairment losses recognized in respect of a CGU are allocated to reduce the carrying amount of the assets in the unit on a pro rata basis.

For assets excluding goodwill, an assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the Company estimates the asset's or CGU's recoverable amount. A previously recognized impairment loss is reversed only if there has been an improvement in the assumptions used to determine the asset's recoverable amount since the last impairment loss was recognized. The reversal is limited so that the carrying amount of the asset does not exceed its recoverable amount, nor exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior periods. Such reversal is recognized in the net income.

(e) Capitalized interest

Interest on major development projects is capitalized until the project is complete using the weighted-average interest rate on all of Harvest's borrowings. Capitalized interest is limited to the actual interest incurred.

(f) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method. The cost of an acquisition including any contingent consideration, is measured as the aggregate of the consideration transferred at acquisition date fair value. The acquired identifiable net assets are measured at their fair value at the date of acquisition. Any excess of the consideration transferred over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the consideration transferred below the fair value of the net assets acquired is recorded as a gain in net income. Associated transaction costs are expensed when incurred.

Those petroleum reserves and resources that are able to be reliably valued are recognized in the assessment of fair values on acquisition. The fair value of oil and natural gas interests is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on reserve estimates. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to groups of CGUs that are expected to benefit from the combination. Goodwill is carried at cost less impairment and is not amortized.

An impairment loss in respect of goodwill is not reversed. Goodwill is assessed for impairment annually at year-end or more frequently if events occur that could result in impairment. The recoverable amount is determined by calculating the recoverable amount of the group of CGUs goodwill has been allocated to. The excess of the carrying value of goodwill over the recoverable amount is then recognized as impairment and charged to income in the period in which it occurs.

(g) Provisions

(i) General

Provisions are recognized when the Company has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where the Company expects some or all of a provision to be reimbursed, for example, under an insurance contract, the reimbursement is recognized as a separate asset but only when

the reimbursement is virtually certain. The expense relating to any provision is presented in the income statement net of any reimbursement. If the effect of the time value of money is material, provisions are discounted using a current discount rate that reflects, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognized as a finance cost.

(ii) Decommissioning Liabilities

Harvest recognizes the present value of any decommissioning liabilities as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and normal use of the assets. Harvest uses a risk-free rate to estimate the present value of the expenditure required to settle the present obligation at the reporting date. The associated decommissioning costs are capitalized as part of the carrying amount of the related asset and the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligation are charged against the decommissioning liabilities.

(iii) Contingencies

A contingency is disclosed where the existence of an obligation will only be confirmed by future events, or where the amount of a present obligation cannot be measured reliably or will likely not result in an economic outflow. Contingent assets are only disclosed when the inflow of economic benefits is probable.

(h) Income Taxes

Income tax expense comprises current and deferred tax. Income tax expense is recognized in net income except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income tax liabilities and assets are generally not recognized for temporary differences arising on:

- investments in subsidiaries and associates and interests in joint ventures;
- the initial recognition of goodwill; or
- the initial recognition of an asset or liability in a transaction which is not a business combination.

Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, and Harvest intends to settle current tax liabilities and assets on a net basis.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(i) Post-Employment Benefits

Harvest's Downstream operations maintains a defined benefit plan and provides certain post-retirement health care benefits, which cover the majority of its employees and their surviving spouses. The cost of providing the defined pension benefits and other post-retirement benefits is actuarially determined using the projected unit credit method reflecting management's best estimates of discount rates, rate of return on plan assets, rate of compensation increase, retirement ages of employees, and expected health care costs. Post-employment benefit expense includes the cost of benefits earned during the current year, the interest cost on the obligations and the expected return on plan assets.

Pension plan assets are measured at fair values with the difference between the fair value of the plan assets and the total employee benefit obligation recorded on the balance sheet. Actuarial gains or losses are recognized in other comprehensive income immediately.

(j) Currency Translation

Foreign currency-denominated transactions are translated to the respective functional currencies of Harvest's entities at exchange rates at the date of the transactions. Non-monetary items measured at historical cost are not subsequently re-translated. Monetary assets and liabilities denominated in foreign currencies are converted into Harvest's functional currencies at the exchange rate at the reporting date. Conversion gains and losses on monetary items are included in net income in the period in which they arise.

Harvest's Downstream operations' functional currency is the U.S. dollar, while Harvest's presentation currency is the Canadian dollar. Therefore, the Downstream operations' assets and liabilities are translated at the period-end exchange rates, while revenues and expenses are translated using monthly average rates. Translation gains and losses relating to the foreign operations are included in accumulated other comprehensive income as a separate component of shareholder's equity.

(k) Financial Instruments

Harvest recognizes financial assets and financial liabilities, including derivatives, on the consolidated statements of financial position when the Company becomes a party to the contract. Financial liabilities are removed from the consolidated financial statements when the liability is extinguished either through settlement of or release from the obligation of the underlying liability. Financial assets are derecognised when (1) the rights to receive cash flows from the assets have expired or (2) the Company has transferred its rights to receive cash flows from the assets or has assumed an obligation to pay the received cash flows in full without material delay to a third party under a 'pass-through' arrangement; and either (a) the Company has transferred substantially all the risks and rewards of the assets, or (b) the Company has neither transferred nor retained substantially all the risks and rewards of the assets, but has transferred control of the asset.

The Company initially measures all financial instruments at fair value. Subsequent measurement of the financial instruments is based on their classification. Financial assets are classified into the following categories: held for trading, available for sale, held-to-maturity investments and loans and receivables. Financial liabilities are classified as held for trading or other financial liabilities.

Financial assets and financial liabilities classified as held for trading are measured at fair value with changes in those fair values recognized in net income. Financial assets classified as either held-to-maturity or loans and receivables, and other financial liabilities are measured at amortized cost using the effective interest method of amortization. Financial assets classified as available-for-sale are measured at fair values with changes in those fair values recognized in other comprehensive income.

Transaction costs relating to financial instruments classified as held for trading are expensed in net income in the period that they are incurred. For transaction costs that are directly attributable to the acquisition or issuance of financial instruments not classified as held for trading, they are included in the costs of the financial instruments upon initial recognition.

Harvest assesses at each reporting date whether there is any objective evidence that a financial asset or a group of financial assets is impaired, as a result of one or more events that has occurred after the initial recognition of the asset (an incurred 'loss event') and that loss event has an impact on the estimated future cash flows of the financial asset or the group of financial assets that can be reliably estimated.

(l) Hedges

Harvest uses derivative financial instruments such as foreign currency contracts and financial commodity contracts to hedge its foreign currency risks and commodity price risks. Such derivative financial instruments are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. Derivatives are carried as financial assets when the fair value is positive and as financial liabilities when the fair value is negative. Any gains or losses arising from changes in the fair value of derivatives are recorded in net income, except for the effective portion of cash flow hedges, which is recognized in other comprehensive income.

At the inception of a hedge relationship, Harvest formally designates and documents the hedge relationship to which the Company intends to apply hedge accounting. The designation document includes the risk management objective and strategy for undertaking the hedge, the identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged and how the Company will assess the hedge effectiveness. Upon designation and at each reporting date, Harvest assesses hedge effectiveness by comparing the changes in the hedging instrument's fair value or cash flows and the changes in the hedged item's fair value or cash flows attributable to the hedged risk. Only if such hedges are highly effective in achieving offsetting changes in fair value or cash flows will Harvest continue to apply hedge accounting.

The effective portion of the gain or loss on the hedging instrument is recognized directly in other comprehensive income, while any ineffective portion is recognized immediately in net income. Amounts recognized in other comprehensive income are transferred to the statement of comprehensive loss when the hedged transaction affects net income, such as when the hedged forecasted transaction occurs. Where the hedged item is the cost of a non-financial asset or non-financial liability, the amounts recognized in other comprehensive income are transferred to the initial carrying amount of the nonfinancial asset or liability.

If the forecast transaction is no longer expected to occur, the cumulative gain or loss previously recognized in other comprehensive income is transferred to net income. If the hedging instrument expires or is sold, terminated or exercised without replacement or rollover, or if its designation as a hedge is revoked, any cumulative gains or losses previously recognized in other comprehensive income remain in other comprehensive income until the forecast transaction affects net income.

(m) Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash and investments with a maturity date of three months or less and are recorded at fair value.

(n) Investment Tax Credits

Harvest is entitled to certain investment tax credits on qualifying manufacturing capital expenditures relating to its Downstream operations. These credits are recorded as a reduction of the cost of the related asset. The benefits are recognized when the Company has complied with the terms and conditions of applicable tax legislation provided there is reasonable assurance of realization.

(o) Leases

Leases or other arrangements entered into for the use of an asset are classified as either finance or operating leases. Finance leases transfer to the Company substantially all of the risks and benefits incidental to ownership of the leased item. Finance leases are capitalized at the commencement of the lease term at the lower of the fair value of the leased asset or the present value of the minimum lease payments. Capitalized leased assets are amortized over the shorter of the estimated useful life of the assets and the lease term. Operating lease payments are recognized as an expense in the income statement on a straight line basis over the lease term.

(p) Recent Pronouncements

The Company has reviewed new and revised accounting pronouncements that have been issued but are not yet effective and determined that the following may have an impact on the Company.

- On January 1, 2015, Harvest will be required to adopt IFRS 9, "Financial Instruments", which is the result of the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. Restatement of comparative period financial statements is not required upon initial application; however, modified disclosures on transition from the classification and measurement requirements of IAS 39 to IFRS 9 are required. Harvest is in the process of determining the potential impact of the adoption of this new standard.

- In May 2011, the IASB issued the following new standards, which are effective for annual periods beginning on or after January 1, 2013:

  - IFRS 10, "Consolidated Financial Statements", replaces the consolidation requirements in SIC-12, "Consolidation – Special Purpose Entities" and a portion of IAS 27. IFRS 10 builds on existing principles by identifying the concept of control as the determining factor in whether an entity should be included within the consolidated financial statements of the parent company and provides additional guidance to assist in the determination of control where this is difficult to assess. IFRS 10 requires retrospective application and early adoption is permitted.

  - IFRS 11, "Joint Arrangements", focuses on the rights and obligations of the joint arrangement, rather than its legal form (as is currently the case) and requires a single method to account for interests in jointly controlled entities (equity method). This standard requires retrospective application and early adoption is permitted.

  - IFRS 12, "Disclosure of Interest in Other Entities", is a comprehensive standard on disclosure requirements for all forms of interests in other entities, including joint arrangements, associates, structure entities and other off balance sheet interests. IFRS 12 requires retrospective application and early adoption is permitted.

  - IFRS 13, "Fair Value Measurement", provides a consistent definition of fair value, establishes a single framework for determining fair value and introduces requirements for disclosures related to fair value measurement. IFRS 13 applies prospectively from the beginning of the annual period in which the standard is adopted. Early adoption is permitted.

Harvest is assessing the potential financial statement impact from adopting these new standards.

- On June 16, 2011, the IASB issued an amendment to IAS 19, "Employee Benefits", which changes the recognition and measurement of defined benefit pension expense and termination benefits and expands disclosure requirements for all employee benefit plans. The new standard is required to be adopted for periods beginning on or after January 1, 2013. Harvest is currently assessing the financial statement impact of the new standard.

- The IASB issued an amendment to IAS 1, "Presentation of Financial Statements" on June 16, 2011, which requires separating items presented in other comprehensive income between those that are recycled to income and those that are not. The standard is required to be adopted for periods beginning on or after July 1, 2012. The adoption of this standard should not have a material impact on the Company's consolidated financial statements.

- In December 2011, the IASB issued amendments to IFRS 7 "Financial Instruments: Disclosures" and IAS 32, "Financial Instruments: Presentation" to clarify the current offsetting model and develop common disclosure requirements. Amendments to IFRS 7 are effective for annual periods beginning on or after January 1, 2013. Retrospective application is required and early adoption is permitted. Amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014. Retrospective application is required. Harvest is currently assessing the financial statement impact of the new standard.

3. Acquisitions

a) Hunt Acquisition

On February 28, 2011, Harvest acquired certain petroleum and natural gas assets of Hunt Oil Company of Canada, Inc. and Hunt Oil Alberta, Inc. (collectively "Hunt") for total cash consideration of $511.0 million. KNOC provided $505.4 million of equity to fund the acquisition and acquisition costs were $1.3 million (2010 - $0.1 million) for the year ended December 31, 2011. An additional $25 million is payable to Hunt in the event that Canadian natural gas prices exceed certain pre-determined levels in 2012. This potential payable is considered contingent consideration and is required to be fair valued. Based on forecast gas prices, the probability of incurring this payment was assessed as low; as such no fair value was assigned on the allocation of consideration transferred. The Company's assessment of this contingent liability remained the same at December 31, 2011 whereby no provision was recorded.

Hunt reimbursed Harvest for costs associated with restoring production as well as the lost revenues net of operating costs relating to certain properties between October 1, 2010 and April 3, 2011, when production was resumed. A portion of the reimbursement could have reverted to Hunt if the future net revenue earned by Harvest during the six months after April 3, 2011 exceeded the reimbursed amount. Subsequent to the six-month period, it was agreed that no refund of the reimbursement was necessary.

The acquisition was accounted for as a business combination. The fair values of identifiable assets and liabilities, including interim adjustments as at the date of acquisition were:

Property, plant and equipment	$	530,946
Evaluation and exploration assets		18,627
Decommissioning liabilities		(38,030)

Other liabilities		(500)
Cash consideration	$	511,043

The final review of the fair value of the purchase price allocation was completed at December 31, 2011.

From the date of acquisition, the Hunt assets have contributed $133.0 million of revenue and $96.6 million to Harvest's earnings before depletion and income tax in 2011. If the acquisition had been completed on the first day of 2011, Harvest's revenues for the year ended December 31, 2011 would have been $14.6 million higher and the earnings before depletion and income tax would have been $7.4 million higher.

b) Petroleum and Natural Gas Assets

On September 30, 2010, Harvest acquired certain petroleum and natural gas assets including the remaining 40% interest in an operating partnership for total cash consideration of $144.2 million. The acquisition was accounted for as a business combination and acquisition costs were $0.2 million (2010 - $0.3 million) for the year ended December 31, 2011. The fair values of identifiable assets and liabilities as at the date of acquisition were:

Property, plant and equipment	$	166,966
Evaluation and exploration assets		587
Decommissioning liabilities		(18,358)
Deferred tax liabilities		(5,032)
Total cash consideration	$	144,163

The assets have contributed $8.4 million of revenue and $6.0 million to Harvest's earnings before depletion and income tax from the date of acquisition to December 31, 2010. If the acquisition had been completed on the first day of 2010, Harvest's revenues for the year would have been $27.1 million higher and the earnings before depletion and income tax would have been $16.6 million higher.

The final statement of adjustments was received in 2011 and as a result, the property, plant and equipment balance decreased as compared to the provisional value by an immaterial amount. Therefore the 2010 comparative financial statements were not restated. The decrease in depletion, depreciation and amortization as a result of the revised property, plant and equipment balance was also not material.

4. Cash and Cash Equivalents

		December 31, 2011		December 31, 2010		January 1, 2010
Cash on hand and at banks	**$**	**6,607**	$	7,906	$	–
Short-term deposits		–		11,000		–
	$	**6,607**	$	18,906	$	–

5. Inventories

		December 31, 2011		December 31, 2010		January 1, 2010
Petroleum products						
Upstream – pipeline fill	**$**	**1,325**	$	1,010	$	1,183
Downstream		**56,298**		70,586		81,240
Total petroleum product inventory		**57,623**		71,596		82,423
Parts and supplies		**3,329**		3,921		4,396

	$ 60,952	$ 75,517	$ 86,819

For the year ended December 31, 2011, Harvest recognized net inventory impairments of $2.5 million (2010 - $2.4 Million) in its Downstream operations. Such write-downs and recoveries amounts are included as costs in "purchased products for processing and resale" in the consolidated statements of comprehensive loss.

6. Exploration and Evaluation Assets ("E&E")

As at January 1, 2010	$ 36,034
Additions	46,997
Acquisition	–
Dispositions	(971)
Unsuccessful exploration and evaluation costs	(2,858)
Transfer to property, plant and equipment	(19,648)
As at December 31, 2010	$ 59,554
Additions	50,883
Acquisition	18,627
Dispositions	(717)
Unsuccessful exploration & evaluation costs	(17,757)
Transfer to property, plant & equipment	(36,073)
As at December 31, 2011	**$ 74,517**

	Year Ended December 31	
	2011	2010
Pre-licensing costs	**$ 532**	$ 442
Unsuccessful E&E costs	**17,757**	2,858
E&E expense	**$ 18,289**	$ 3,300

7. Property, Plant and Equipment ("PP&E")

	Upstream	**Downstream**	**Total**
Cost:			
As at January 1, 2010	$ 2,940,877	$ 1,113,742	$ 4,054,619
Additions	356,788	71,297	428,085
Acquisitions	574,941	–	574,941
Change in decommissioning liabilities	71,838	2,407	74,245
Transfers from E&E	19,648	–	19,648
Exchange adjustment	–	(63,037)	(63,037)
Disposals	63	(49)	14
Investment tax credits	–	(42,475)	(42,475)
As at December 31, 2010	3,964,155	1,081,885	5,046,040
Additions	682,497	284,244	966,741
Acquisitions	533,963	–	533,963
Change in decommissioning liabilities	(18,245)	3,767	(14,478)
Transfers from E&E	36,073	–	36,073
Exchange adjustment	–	36,928	36,928
Disposals	(882)	(18,031)	(18,913)
Investment tax credits	–	(10,187)	(10,187)
As at December 31, 2011	**$ 5,197,561**	**$ 1,378,606**	**$ 6,576,167**

Accumulated depletion, amortization, depreciation and impairment losses:			
As at January 1, 2010	$ –	$ –	$ –
Depreciation, depletion and amortization	470,641	83,091	553,732
Impairment	13,661	–	13,661
Exchange adjustment	–	(4,589)	(4,589)
As at December 31, 2010	484,302	78,502	562,804
Depreciation, depletion and amortization	535,384	91,006	626,390
Disposals	–	(18,031)	(18,031)
Exchange adjustment	–	4,617	4,617
As at December 31, 2011	**$ 1,019,686**	**$ 156,094**	**$ 1,175,780**
Net Book Value:			
As at December 31, 2011	**$ 4,177,875**	**$ 1,222,512**	**$ 5,400,387**
As at December 31, 2010	$ 3,479,853	$ 1,003,383	$ 4,483,236
As at January 1, 2010	$ 2,940,877	$ 1,113,742	$ 4,054,619

General and administrative costs of $22.2 million (2010 - $14.6 million) and interest of $4.5 million (2010 - $0.4 million) have been capitalized in Upstream PP&E for the year ended December 31, 2011. Interest of $4.1 million (2010 - $nil) have been capitalized in Downstream PP&E during the year ended December 31, 2011. Capitalized interest measured using a weighted average interest rate of 6.65% (2010 - 6.50%) arose from the BlackGold oil sands project (“BlackGold”) and Downstream debottlenecking project.

At December 31, 2011 the following costs were excluded from the asset base subject to depreciation, depletion and amortization: Downstream major parts inventory of $7.5 million (2010 - $6.8 million), Downstream assets under construction of $102.5 million (2010 - $68.8 million) and Upstream BlackGold oil sands project assets of $497.2 million (2010 - $385.3 million). For the year ended December 31, 2011, an investment tax credit of $10.2 million (2010 - $42.5 million) was applied against Downstream assets.

During the year ended December 31, 2011, Harvest recorded an impairment loss of $nil to PP&E. An increase of 50 bps in the pre-tax discount rate would result in an impairment of $38.4 million, while a 10% decrease in gross margin would result in an impairment of $222.3 million in Downstream PP&E. During the year ended December 31, 2010, Harvest recorded a $13.7 million impairment related to certain Upstream properties in Southern Alberta to reflect declining forecasted gas prices which resulted in lower estimated future cash flows using a pre-tax discount rate of 12%. The recoverable amount is based on the assets’ value-in-use, estimated using the net present value of the future cash flow.

8. Goodwill

Goodwill of $404.9 million (2010 - $404.9 million) has been allocated to the Upstream operating segment. In assessing whether goodwill has been impaired, the carrying amount (including goodwill) is compared with the recoverable amount of the Upstream operating segment. At December 31, 2011, the recoverable amount was determined by using the expected cash flows generated from the projected oil and natural gas production profiles up to the expected dates of cessation of production. The key assumptions required to estimate the recoverable amount are the oil and natural gas prices, production volumes and the discount rate. The values assigned to the key assumptions represent management’s assessment of future trends in the oil and gas industry based on both external and internal sources. A pre-tax discount rate of 10% (and the following forward commodity price estimates) were used in the goodwill impairment calculation:

	WTI Crude Oil	AECO Gas	US$/Cdn$ Exchange

Year	($US/bbl)[1]	($Cdn/Mmbtu)[1]	Rate[1]
2012	97.50	3.50	0.975
2013	97.50	4.20	0.975
2014	100.00	4.70	0.975
2015	100.80	5.10	0.975
2016	101.70	5.55	0.975
2017	102.70	5.90	0.975
2018	103.60	6.25	0.975
2019	104.50	6.45	0.975
2020	105.40	6.70	0.975
2021	107.60	6.85	0.975
2022	109.70	6.95	0.975
2023	111.90	7.05	0.975
2024	114.10	7.20	0.975
2025	116.40	7.40	0.975
2026	118.80	7.55	0.975
Thereafter[2]	+2%/year	+2%/year	0.975

(1) Source: McDaniel & Associates Consultants Ltd, effective January 1, 2012.
(2) Percentage change represents the change in each year after 2026 to the end of the reserve life.

Management believes that currently, there is no reasonably possible change in the key assumptions that would cause the carrying amount of the Upstream operating segment to exceed the recoverable amount.

9. Decommissioning Liabilities

Harvest's decommissioning liabilities arise from its net ownership interests in petroleum and natural gas assets including well sites, gathering systems, pipeline, processing facilities and Downstream refining and marketing assets and its legal obligations to retire and reclaim them. Harvest estimates the total undiscounted amount of cash flows required to settle its decommissioning liabilities to be approximately $1.4 billion at December 31, 2011 (2010 - $1.2 billion), which will be incurred between 2012 and 2072. A risk-free discount rate of 3.0% (2010 - 3.4%) and inflation rate of 1.7% (2010 - 1.7%) were used to calculate the fair value of the decommissioning liabilities. Revisions in decommissioning liabilities in 2011 resulted from changes in the discount rates, estimated abandonment dates and estimated costs, while 2010 revisions resulted from a change in the discount rate. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning work required, which will reflect market conditions at the relevant time. Furthermore, the timing of decommissioning is likely to depend on when the fields cease to produce at economically viable rates. This in turn will depend upon future oil and gas prices, which are inherently uncertain. A reconciliation of the decommissioning liabilities is provided below:

	Upstream	Downstream	Total
Balance at January 1, 2010	$ 559,810	$ 7,676	$ 567,486
Liabilities assumed on acquisitions	22,393	–	22,393
Liabilities incurred	9,316	–	9,316
Settled during the period	(20,257)	–	(20,257)
Revisions (change in estimate)	58,989	2,407	61,396
Accretion	22,342	343	22,685
Balance at December 31, 2010	652,593	10,426	663,019
Liabilities assumed on acquisitions	38,030	–	38,030
Liabilities incurred	28,382	–	28,382
Settled during the period	(22,110)	–	(22,110)
Revisions (change in estimate)	(46,627)	3,767	(42,860)

Disposals	(708)	–	(708)
Accretion	23,151	400	23,551
Balance at December 31, 2011	**$ 672,711**	**$ 14,593**	**$ 687,304**
Current portion of decommissioning liabilities	$ 12,782	$ –	$ 12,782
Non-current portion of decommissioning liabilities	659,929	14,593	674,522
Balance at December 31, 2011	**$ 672,711**	**$ 14,593**	**$ 687,304**

10. Bank Loan

At the time of the purchase of Harvest Energy Trust ("Trust") by KNOC Canada on December 22, 2009, the Trust had renegotiated a temporary credit facility of $600 million with the maturity date of April 30, 2010. At January 1, 2010, $428 million was drawn under the credit facility. On April 30, 2010, Harvest entered into an amended and extended credit facility maturing April 30, 2013 and the facility was reduced from $600 million to $500 million.

On April 29, 2011, Harvest further extended the term of its credit facility by 2 years to April 30, 2015. Harvest pays a floating interest rate under its credit facility, which is determined by a grid based on the Company's secured debt (excluding $6^{7/8}$ % senior notes and convertible debentures) to earnings before interest, taxes, depletion, amortization and other non-cash items ("EBITDA"). The minimum rate charged on the credit facility was amended on April 29, 2011, decreasing the floating rate from 200 bps to 175 bps over bankers' acceptance rates, to the extent that Harvest's secured debt to EBITDA ratio remains below or equal to one.

On December 16, 2011, the credit facility was amended to increase the capacity of the facility from $500 million to $800 million and the minimum rate charged on the credit facility decreased further from 175 bps to 160 bps over bankers' acceptance rates. The determination of the financial covenants remains unchanged and is disclosed below. At December 31, 2011, Harvest had $358.9 million drawn from the $800 million available under the credit facility (2010 - $14 million).

The credit facility is secured by a first floating charge over all of the assets of Harvest's operating subsidiaries plus a first mortgage security interest on the Downstream operation's refinery assets. The most restrictive covenants of Harvest's credit facility include an aggregate limitation of $25 million on financial assistance and/or capital contributions to parties other than those included in the first floating charge, a limitation to carrying on business in countries that are not members of the Organization of Economic Co-operation and Development and a limitation on the payment of distributions to the shareholder in certain circumstances such as an event of default. The credit facility requires standby fees on undrawn amounts and interest on amounts borrowed at varying rates depending on Harvest's ratio of secured debt (excluding the $6^{7/8}$% senior notes and convertible debentures) to its EBITDA. In addition to the availability under this facility being limited by the borrowing base covenant of the $6^{7/8}$% senior notes described in note 11, availability is subject to the following quarterly financial covenants as defined in the credit facility agreement:

	Covenant	**December 31, 2011**	December 31, 2010
Secured debt [1] to Annualized EBITDA	3.0 to 1.0 or less	**0.73**	0.06
Total debt [2] to Annualized EBITDA	3.5 to 1.0 or less	**2.72**	2.39
Secured debt [1] to Capitalization [3]	50% or less	**10%**	1%
Total debt [2] to Capitalization [3]	55% or less	**36%**	31%

(1) Secured debt consists of letters of credit of $8.7 million (2010 – $2.5 million), bank loan of $355.6 million (2010 - $11.4 million) and guarantees of $92.1 million (2010 - $15.5 million) at December 31,

2011.
(2) Total debt consists of secured debt, convertible debentures and senior notes.
(3) Capitalization consists of total debt and shareholder's equity less equity for BlackGold of $459.9 million at December 31, 2010 and 2011.

For the year ended December 31, 2011 interest charges on the bank loan aggregated to $5.7 million (2010 - $5.7 million) reflecting an effective interest rate of 3.0% (2010 – 3.7%).

11. Senior Notes

On October 4, 2010, Harvest issued US$500 million of $6^{7/8}$ % senior notes for net cash proceeds of US$484.6 million. The senior notes are unsecured with interest payable semi-annually on April 1 and October 1 and mature on October 1, 2017. The senior notes are unconditionally guaranteed by Harvest and all of its wholly-owned subsidiaries that guarantee the revolving credit facility and every future restricted subsidiary that guarantees certain debt. The notes are redeemable at a redemption price equal to 100% of the principal amount of the notes being redeemed plus a make-whole redemption premium, plus accrued and unpaid interest to the redemption date. Harvest may also redeem the notes at any time in the event that certain changes affecting Canadian withholding taxes occur.

There are covenants restricting, among other things, the sale of assets and the incurrence of additional indebtedness if such issuance would result in an interest coverage ratio, as defined, of less than 2.0 to 1. Notwithstanding the interest coverage ratio limitation, the incurrence of additional indebtedness under the credit facilities may be limited by the borrowing base covenant and certain other specific circumstances. The covenant restricts Harvest's incurrence of indebtedness under the credit facility in an aggregate principal amount not to exceed the greater of $1.0 billion and 15% of total assets. In addition, the covenants of the senior notes restrict the amount of dividends Harvest can pay to shareholders; no dividends have been paid during the year ended December 31, 2011.

In 2010, Harvest redeemed the US$250 million of $7^{7/8}$ % senior notes for total consideration of $256.9 million.

12. Convertible Debentures

Harvest has four series of convertible unsecured subordinated debentures outstanding. Interest on the debentures is payable semi-annually in arrears in equal installments on dates prescribed by each series.

As a result of KNOC'S acquisition of Harvest Energy Trust, in 2009, the debentures are no longer convertible into units but investors would receive $10.00 for each unit notionally received based on each series conversion rate. Because every series of debentures carry a conversion price that exceeds $10.00 per unit, it is assumed that no investor would exercise their conversion option.

The debentures may be redeemed by Harvest at its option in whole or in part prior to their respective redemption dates. The redemption price for the first redemption period is at a price equal to $1,050 per debenture and at $1,025 per debenture during the second redemption period. After the second redemption period, the debentures are redeemable at par. Any redemption will include accrued and unpaid interest at such time.

The following is a summary of the four series of convertible debentures:

Series	Interest Rate	Conversion price / share	Maturity	First redemption period	Second redemption period
D	6.40%	$ 46.00	Oct. 31, 2012	Nov. 1/08-Oct. 31/09	Nov. 1/09-Oct. 31/10

E	7.25%	$ 32.20	Sept. 30, 2013	Oct. 1/09-Sept. 30/10	Oct. 1/10-Sept. 30/11
F	7.25%	$ 27.25	Feb. 28, 2014	Mar. 1/10-Feb. 28/11	Mar. 1/11-Feb. 29/12
G	7.50%	$ 27.40	May 31, 2015	Jun. 1/11-May 31/12	Jun. 1/12-May 31/13

The following table summarizes the face value, carrying amount and fair value of the convertible debentures:

	December 31, 2011			December 31, 2010			January 1, 2010		
Series	**Face Value**	**Carrying Amount**	**Fair Value**	Face Value	Carrying Amount	Fair Value	Face Value	Carrying Amount	Fair Value
B	$ –	$ –	$ –	$ –	$ –	$ –	$ 37,062	$ 37,562	$ 37,562
D	**106,796**	**107,146**	**108,184**	106,796	107,544	108,291	174,626	176,460	176,460
E	**330,548**	**333,346**	**337,159**	330,548	334,804	339,142	379,256	385,703	385,703
F	**60,050**	**60,616**	**61,551**	60,050	60,851	61,912	73,222	74,467	74,467
G	**236,579**	**240,959**	**245,451**	236,579	242,058	248,763	250,000	256,875	256,875
	$ 733,973	**$ 742,067**	**$ 752,345**	$ 733,973	$ 745,257	$ 758,108	$ 914,166	$ 931,067	$ 931,067

The KNOC acquisition of the Trust triggered the "change of control" provision included within the convertible debentures' indentures, which required Harvest to make an offer to purchase 100% of the outstanding convertible debentures for cash consideration of 101% of the principal amount thereof plus accrued and unpaid interest. Harvest made these offers on January 20, 2010 and by March 4, 2010 all of the offers had expired. The following redemptions were made:

- Series B – $13.3 million principal amount tendered, with the remaining principal balance of $23.8 million maturing on December 31, 2010
- Series D – $67.8 million principal amount tendered leaving a principal balance of $106.8 million outstanding
- Series E – $48.7 million principal amount tendered leaving a principal balance of $330.5 million outstanding
- Series F – $13.2 million principal amount tendered leaving a principal balance of $60.1 million outstanding
- Series G – $13.4 million principal amount tendered leaving a principal balance of $236.6 million outstanding

13. Shareholder's Capital

(a) Authorized

The authorized capital consists of an unlimited number of common shares with no par value and an unlimited number of preferred shares issuable in series.

(b) Number of Common Shares Issued

Outstanding at January 1, 2010	242,268,802
Issued to KNOC at $10.00 per share to fund debt repayment	46,567,852
Issued to KNOC at $10.00 per share for BlackGold consideration *[Note 26]*	37,416,913
Issued to KNOC at $10.00 per share for BlackGold project development	4,700,000
Issued to KNOC at $10.00 per share for BlackGold project development	3,868,600
Issued to KNOC at $10.00 per share for KNOC Global Technology and Research centre	712,880
Outstanding at December 31, 2010	335,535,047
Issued to KNOC at $10.00 per share for Hunt acquisition	50,543,602
Outstanding at December 31, 2011	**386,078,649**

14. Capital Structure

Harvest considers its capital structure to be its credit facility, senior notes, convertible debentures and shareholder's equity.

	December 31, 2011	December 31, 2010	January 1, 2010
Bank loan[1]	**$ 358,885**	$ 14,000	$ 428,017
$6^{7/8}$% senior notes[1][2]	**508,500**	497,300	-
$7^{7/8}$% senior notes[1][2]	**–**	–	262,750
Principal amount of convertible[1] debentures	**733,973**	733,973	914,166
	1,601,358	1,245,273	1,604,933
Shareholder's equity	**3,453,644**	3,016,855	2,219,513
	$ 5,055,002	$ 4,262,128	$ 3,824,446

(1) Excludes deferred financing costs.
(2) Face value converted at the period end exchange rate.

Harvest's primary objective in its management of capital resources is to have access to capital to fund its financial obligations as well as future growth. Harvest monitors its capital structure and makes adjustments according to market conditions to remain flexible while meeting these objectives. Accordingly, Harvest may adjust its capital spending programs, issue equity, issue new debt or repay existing debt.

Harvest evaluates its capital structure using the following financial ratios: bank loan to twelve month trailing EBITDA and total debt to total debt plus shareholder's equity. These ratios are also included in the externally imposed capital requirements per the Company's credit facility, senior notes and convertible debentures; Harvest was in compliance with all debt covenants at December 31, 2011.

15. Revenue and Other Income

	Year Ended December 31	
	2011	2010
Crude oil and natural gas sales, net of royalty	**$ 1,100,838**	$ 852,247
Refinery products sales	**3,239,455**	3,105,957
Effective portion of realized crude oil hedges	**(9,424)**	–
	$ 4,330,869	$ 3,958,204

16. Operating and General and Administrative ("G&A") Expenses

	Year Ended December 31					
	2011			2010		
Operating expenses	**Upstream**	**Downstream**	**Total**	Upstream	Downstream	Total
Power and purchased energy	**$ 83,092**	**$ 117,275**	**$ 200,367**	$ 59,106	$ 106,126	$ 165,232
Well servicing	**61,592**	**–**	**61,592**	50,427	–	50,427
Repairs and maintenance	**60,038**	**20,407**	**80,445**	43,720	22,341	66,061
Lease rentals and property taxes	**34,728**	**–**	**34,728**	30,637	–	30,637
Salaries and benefits	**28,137**	**58,907**	**87,044**	22,641	60,959	83,600
Professional and consultation fees	**19,378**	**4,519**	**23,897**	15,966	3,784	19,750
Chemicals	**15,360**	**–**	**15,360**	12,981	–	12,981
Processing fees	**22,643**	**–**	**22,643**	13,538	–	13,538
Trucking	**13,261**	**–**	**13,261**	9,645	–	9,645
Other	**12,227**	**24,567**	**36,794**	6,932	22,430	29,362
	$ 350,456	**$ 225,675**	**$ 576,131**	$ 265,593	$ 215,640	$ 481,233

General and administrative expenses	Year Ended December 31 **2011**	2010
Salaries and benefits	**$ 59,543**	$ 44,545
Professional and consultation fees	**7,864**	8,387
Other	**18,512**	9,334
G&A capitalized and recovery	**(23,351)**	(15,199)
	$ 62,568	$ 47,067

17. Finance Costs

	Year Ended December 31 **2011**	2010
Interest and other finance charges	**$ 94,216**	$ 78,520
Accretion of decommissioning liabilities	**23,551**	22,685
Less: capitalized interest	**(8,640)**	(397)
	$ 109,127	$ 100,808

18. Foreign Exchange

	Year Ended December 31 **2011**	2010
Realized (gains) losses on foreign exchange	**$ (6,541)**	$ (1,524)
Unrealized (gains) losses on foreign exchange	**2,555**	(1,875)
	$ (3,986)	$ (3,399)

19. Supplemental Cash Flow Information

	Year Ended December 31 **2011**	2010
Source (use) of cash:		
Accounts receivable and other	**$ 1,679**	$ (35,269)
Prepaid expenses (including long-term deposit)	**42,223**	(70,123)
Inventories	**14,565**	11,302
Accounts payable	**103,661**	155,109
Net changes in non-cash working capital	**162,128**	61,019
Changes relating to operating activities	**51,061**	32,299
Changes relating to financing activities	**-**	1,952
Changes relating to investing activities	**108,747**	22,503
Add: Non-cash changes	**2,320**	4,265
	$ 162,128	$ 61,019

20. Income Taxes

	Year Ended December 31 **2011**	2010
Current income tax expense (recovery)	**$ 53**	$ (212)
Deferred income tax (“DIT”) recovery	**(29,880)**	(65,097)
	$ (29,827)	$ (65,309)

The income tax recovery varies from the amount that would be computed by applying the relevant Canadian income tax rates to reported losses before taxes as follows:

	Year Ended December 31	
	2011	2010
Loss before income tax	**$ (134,484)**	$ (146,472)
Combined Canadian federal and provincial statutory income tax rate	**28.08%**	28.25%
Computed income tax recovery at statutory rates	**(37,763)**	(41,378)
Increased expense (recovery) resulting from the following:		
Difference between current and expected tax rates	**13,894**	(12,862)
Foreign exchange impact not recognized in income	**7,848**	(10,931)
Amended returns and pool balances	**4,946**	-
Change in valuation allowance	**(12,692)**	-
Non-deductible expenses	**(3,499)**	(2,409)
Other	**(2,561)**	(212)
Non-taxable portion of capital loss	**-**	2,483
Income tax recovery	**$ (29,827)**	$ (65,309)

The change in the applicable tax rate for the year ended December 31, 2011 from the previous year is due to a reduction in the federal component of the tax rate.

Movements in the DIT asset (liability) are as follows:

	PP&E	Decommissioning liabilities	Non-capital tax losses	Other	Total deferred asset (Liability)
At January 1, 2010	$ (574,644)	$ 144,867	$ 289,647	$ (1,975)	$ (142,105)
Recognized in profit or loss	23,205	23,615	13,469	4,808	65,097
Acquired in business combination	(5,032)	–	–	–	(5,032)
Recognized in other comprehensive loss	–	–	–	2,530	2,530
At December 31, 2010	$ (556,471)	$ 168,482	$ 303,116	$ 5,363	$ (79,510)[1]
Recognized in profit or loss	(48,823)	3,898	71,921	2,884	29,880
Recognized in other comprehensive loss	–	–	–	(5,277)	(5,277)
At December 31, 2011	**$ (605,294)**	**$ 172,380**	**$ 375,037**	**$ 2,970**	**$ (54,907)**

(1) The net DIT liability at December 31, 2010 consists of a $1.6 million DIT asset and an $81.1 million DIT liability.

DIT assets are recognized to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax losses can be utilized. As at December 31, 2011, Harvest had approximately $1.6 billion of carry-forward tax losses that would be available to offset against future taxable profit. A DIT asset has been recognized in respect of all of these losses, and is included in the net DIT liability of $54.9 million. The DIT asset related to the carry-forward losses has been recorded despite the fact that the Company has incurred losses before income tax in 2010 and 2011. The Company has tax planning opportunities available that could support full recognition of these losses as a DIT asset.

21. Post-Employment Benefits

The measurement of the accrued benefit obligation and annual expense for the defined benefit plans requires actuarial calculations and the following key assumptions.

	December 31, 2011		December 31, 2010		January 1, 2010	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans	Pension Plans	Other Benefit Plans
Discount rate	**5.0%**	**5.0%**	5.25%	5.25%	5.5%	5.5%
Expected long-term rate of return on plan assets	**7.0%**	–	7.0%	–	7.0%	–
Rate of compensation increase	**3.5%**	–	3.5%	–	3.5%	–
Employee contribution of pensionable income	**6.0%**	–	6.0%	–	6.0%	–
Annual rate of increase in covered health care benefits	–	**8%**	–	8%	-	9%

The defined benefit pension plan asset mix is as follows:

	December 31, 2011	December 31, 2010	January 1, 2010
Bonds/fixed income securities	**30%**	32%	31%
Equity securities	**70%**	68%	69%

Total cash payments for employee future benefits, consisting of cash contributed by Harvest to the pension plans and other benefit plans was $3.6 million for the year ended December 31, 2011 (2010 - $3.9 million); the expected contribution for the pension plans and other benefit plans in 2012 is $5.3 million.

The expected long-term rates of return are estimated based on many factors, including the expected forecast for inflation, risk premiums for each class of asset, and current and future financial market conditions.

The defined benefit plans were subject to an actuarial valuation on December 31, 2011, and the next valuation report is due December 31, 2012.

	December 31, 2011			December 31, 2010		
	Pension Plans	**Other Benefit Plans**	**Total**	Pension Plans	Other Benefit Plans	Total
Employee benefit obligation, beginning of period	**$ 63,791**	**$ 7,901**	**$ 71,692**	$ 56,476	$ 7,047	$ 63,523
Current service costs	**2,466**	**285**	**2,751**	2,189	291	2,480
Interest costs	**3,507**	**423**	**3,930**	3,258	397	3,655
Employee contributions	**1,606**	**202**	**1,808**	1,526	170	1,696
Actuarial gain (loss)	**1,572**	**(137)**	**1,435**	2,250	423	2,673
Benefits paid	**(2,123)**	**(481)**	**(2,604)**	(1,908)	(427)	(2,335)
Employee benefit obligation, end of period	**$ 70,819**	**$ 8,193**	**$ 79,012**	$ 63,791	$ 7,901	$ 71,692

Fair value of plan assets, beginning of period	**$ 51,327**	**$ –**	**$ 51,327**	$ 46,070	$ –	$ 46,070

Expected return on plan assets	**3,623**	–	**3,623**	3,277	–	3,277
Actuarial loss	**(4,678)**		**(4,678)**	(1,243)	–	(1,243)
Employer contributions	**3,299**	**279**	**3,578**	3,605	257	3,862
Employee contributions	**1,606**	**202**	**1,808**	1,526	170	1,696
Benefits paid	**(2,123)**	**(481)**	**(2,604)**	(1,908)	(427)	(2,335)
Fair value of plan assets, end of period	**$ 53,054**	**$ –**	**$ 53,054**	$ 51,327	$ –	$ 51,327
Funded status – deficit	**$ (17,765)**	**$ (8,193)**	**$ (25,958)**	$ (12,464)	$ (7,901)	$ (20,365)
Experience adjustments arising on plan assets	**(8.8)%**	–		(2.4)%	–	
Experience adjustments arising on plan liabilities	**(2.2)%**	**1.7%**		(3.5)%	(5.4)%	

The table below shows the components of the net benefit plan expense:

	Year Ended December 31					
	2011			2010		
	Pension Plans	**Other Benefit Plans**	**Total**	Pension Plans	Other Benefit Plans	Total
Current service cost	**$ 2,466**	**$ 285**	**$ 2,751**	$ 2,189	$ 291	$ 2,480
Interest costs	**3,507**	**423**	**3,930**	3,258	397	3,655
Expected return on assets	**(3,623)**	–	**(3,623)**	(3,277)	–	(3,277)
Net benefit plan expense	**$ 2,350**	**$ 708**	**$ 3,058**	$ 2,170	$ 688	$ 2,858

The actual loss on plan assets for the year ended December 31, 2011 was $1.1 million (December 31, 2010 - a return of $2.0 million).

For the year ended December 31, 2011 the net benefit plan expense of $3.1 million (2010 - $2.9 million) has been included in operating expenses in the statement of comprehensive loss. An actuarial loss of $4.9 million, net of tax of $1.2 million (2010 - $3.2 million, net of tax of $0.7 million) has been included in other comprehensive income. The cumulative amount of actuarial loss included in accumulated other comprehensive loss as at December 31, 2011 is $8.1 million, net of tax of $1.9 million.

Under the pension regulations, North Atlantic is required to fund its defined benefit pension plan obligation within 5 to 15 years. The funding requirements are included in note 25.

A 1 % change in the expected health care cost trend rate would have an immaterial annual impact on post-retirement benefit expense and projected benefit obligation as at December 31, 2011.

22. Accumulated Other Comprehensive Income (Loss)

	Foreign Currency Translation Adjustment	Gains (Losses) on Designated Cash Flow Hedges, Net of Tax	Actuarial Loss, Net of Tax	Total
Balance at January 1, 2010	$ –	$ –	$ –	$ –

Losses on derivatives designated as cash flow hedges	–	(5,020)	–	(5,020)
Actuarial loss	–	–	(3,217)	(3,217)
Losses on foreign currency translation	(45,920)	–	–	(45,920)
Balance at December 31, 2010	(45,920)	(5,020)	(3,217)	(54,157)
Reclassification to net income of losses on cash flow hedges	–	(7,050)	–	7,050
Gains on derivatives as designated cash flow hedges	–	26,471	–	12,371
Actuarial loss	–	-	(4,891)	(4,891)
Gains on foreign currency translation	21,480	-	-	21,480
Balance at December 31, 2011	**$ (24,440)**	**$ 14,401**	**$ (8,108)**	**$ (18,147)**

The effective portion of the unrealized gain of $26.5 million net of tax of $8.9 million (2010 - $5.0 million loss net of tax recovery of $1.8 million) was included in other comprehensive loss for the year ended December 31, 2011. The amount removed from accumulated other comprehensive loss and included in petroleum, natural gas, and refined product sales was a loss of $7.1 million, net of tax recovery of $2.4 million for the year ended December 31, 2011 (2010 - $nil).

The Company expects that $14.4 million of gains reported in accumulated other comprehensive loss will be released to net income within the next 12 months.

23. Financial Instruments

(a) Fair Values

Financial instruments of Harvest consist of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, bank loan, risk management contracts, convertible debentures and senior notes.

The carrying value and fair value of these financial instruments are disclosed below by financial instrument category:

	December 31, 2011		December 31, 2010		January 1, 2010	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets						
Loans and Receivables						
Accounts receivable	**$ 212,252**	**$ 212,252**	$ 213,931	$ 213,931	$ 178,662	$ 178,662
Held for Trading						
Cash and cash equivalents	**6,607**	**6,607**	18,906	18,906	-	-
Risk management contracts	**20,162**	**20,162**	1,007	1,007	-	-
Total Financial Assets	**$ 239,021**	**$ 239,021**	$ 233,844	$ 233,844	$ 178,662	$ 178,662
Financial Liabilities						
Held for Trading						
Risk management contracts	$ –	$ –	$ 7,553	$ 7,553	$ 2,052	$ 2,052
Measured at Amortized Cost						
Accounts payable and accrued liabilities	**464,148**	**464,148**	360,487	360,487	205,378	205,378
Bank loan	**355,575**	**358,885**	11,379	14,000	428,017	428,017
$6^{7/8}$ % senior notes	**495,674**	**523,119**	482,389	507,246	-	-
$7^{7/8}$ % senior notes	**-**	**-**	-	-	265,377	265,377
Convertible debentures	**742,067**	**752,345**	745,257	758,108	931,067	931,067
Total Financial Liabilities	**$ 2,057,464**	**$ 2,098,497**	$ 1,607,065	$ 1,647,394	$ 1,831,891	$ 1,831,891

Harvest enters into risk management contracts with various counterparties, principally financial institutions with investment grade credit ratings. Derivatives valued using valuation techniques with market observable inputs are mainly foreign exchange contracts and financial commodity contracts. The most frequently applied valuation techniques include forward pricing and swap models, using present value calculations. The models incorporate various inputs including the credit quality of counterparties, foreign exchange spot and forward rates, interest rate curves and forward rate curves of the underlying commodity.

The fair values of the risk management contracts are net of a credit valuation adjustment attributable to derivative counterparty default risk or the Company's own default risk. The changes in counterparty credit risk had no material effect on the hedge effectiveness assessment for derivatives designated in the hedging relationship and other financial instruments recognized at fair value.

The fair values of the convertible debentures and the senior notes are based on quoted market prices as at December 31, 2011. The fair value of the bank loan approximates the carrying value (excluding deferred financing charges) as the bank loan bears floating market rates. The carrying value of the bank loan includes $3.3 million of deferred financing charges at December 31, 2011 (2010 - $2.6 million). Due to the short term maturities of accounts receivable and accounts payable and accrued liabilities, their carrying values approximate their fair values.

Harvest's financial assets and liabilities recorded at fair value have been classified according to the following hierarchy based on the significance of observable inputs used to value the instrument:

Level 1: quoted (unadjusted) prices in active markets for identical assets or liabilities. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: other techniques for which all inputs which have a significant effect on the recorded fair value are observable, either directly or indirectly.

Level 3: techniques which use inputs that have a significant effect on the recorded fair value that are not based on observable market data.

Harvest's cash and cash equivalents and risk management contracts have been assessed on the fair value hierarchy described above. Cash and cash equivalents are classified as Level 1 and risk management contracts as Level 2. During the year ended December 31, 2011, there were no transfers among Levels 1, 2 and 3.

(b) Risk Management Contracts

Harvest uses electricity price swap contracts to manage some of its price risk exposure. These swap contracts are not designated as hedges and are entered into for periods consistent with forecast electricity purchases.

The Company enters into crude oil and foreign exchange contracts to reduce the volatility of cash flows from some of its forecast sales. Harvest designates all of its crude oil derivative contracts and certain foreign exchange contracts as cash flow hedges. The effective portion of the unrealized gains and losses is included in other comprehensive income. The effective portion of the realized gains and losses is removed from accumulated other comprehensive income and included in petroleum, natural gas, and refined product sales (see note 22). The ineffective portion of the unrealized and realized gains and losses recognized in the consolidated income statement from these cash flow hedges is shown below for crude oil, together with the realized and unrealized (gains) losses on power and currency risk management contracts:

	Year Ended December 31							
	2011				2010			
	Power	**Crude oil**	**Currency**	**Total**	Power	Crude oil	Currency	Total
Realized (gains) losses	**$ (7,730)**	**$ 1,730**	**$ –**	**$ (6,000)**	$ 1,808	$ –	$ –	$ 1,808
Unrealized (gains) losses	**1,008**	**(1,754)**	**–**	**(746)**	(3,060)	702	–	(2,358)
	$ (6,722)	**$ (24)**	**$ –**	**$ (6,746)**	$ (1,252)	$ 702	$ –	$ (550)

The following is a summary of Harvest's risk management contracts outstanding at December 31, 2011 and 2010:

Contracts Designated as Hedges

		December 31, 2011		
Contract Quantity	**Type of Contract**	**Term**	**Contract Price**	**Fair Value**
4,200 bbls/day	Crude oil price swap	2012	US $111.37/bbl	$ 19,718
US $468/day	Foreign exchange swap	2012	$1.0236 Cdn/US	444
				$ 20,162

(c) Risk Exposure

Harvest is exposed to market risks resulting from fluctuations in commodity prices, currency exchange rates and interest rates in the normal course of operations. Harvest is also exposed, to a lesser extent, to credit risk on accounts receivable, counterparty risk from price risk management contracts and to liquidity risk relating to the Company's debt.

(i.) Credit Risk

Upstream Accounts Receivable

Accounts receivable in Harvest's Upstream operations are due from crude oil and natural gas purchasers as well as joint venture partners in the petroleum and natural gas industry and are subject to normal industry credit risks. Concentration of credit risk is mitigated by having a broad customer base, which includes a significant number of companies engaged in joint operations with Harvest. Harvest periodically assesses the financial strength of its crude oil and natural gas purchasers and will adjust its marketing plan to mitigate credit risks. This assessment involves a review of external credit ratings; however, if external ratings are not available, Harvest requests a guarantee from the parent company that does have a credit rating. If this is not possible, Harvest performs an internal credit review based on the purchaser's past financial performance. The credit risk associated with joint venture partners is mitigated by reviewing the credit history of partners and requiring some partners to provide cash prior to incurring significant capital costs on their behalf. Additionally, most agreements have a provision enabling Harvest to use the proceeds from the sale of production that would otherwise be taken in kind by the partner to offset amounts owing from the partner that is in default. Generally, the only instances of impairment are when a purchaser or partner is facing bankruptcy or extreme financial distress.

Risk Management Contract Counterparties

Harvest is exposed to credit risk from the counterparties to its risk management contracts. This risk is managed by diversifying Harvest's risk management portfolio among a number of counterparties limited to lenders in its syndicated credit facilities; Harvest has no history of losses with these counterparties.

Downstream Accounts Receivable

The supply and off take agreement exposes Harvest to the credit risk of Macquarie Energy Canada Ltd. ("Macquarie") as all feedstock purchases and the majority of product sales are made with Macquarie. This credit risk is mitigated by the amounts owing to Macquarie for feedstock purchases that are offset against amounts receivable from Macquarie for product sales with the balance being net settled. The supply and off take agreement also requires both Harvest and Maquarie's parent, Macquarie Bank Ltd, to provide reciprocal guarantees of US$75 million to each other in order to mitigate the risk of either counter party being unable to settle a net payable amount. At December 31, 2011, Harvest is in a net payable position with Macquarie and the outstanding balance is included in current trade accounts payable in the liability liquidity table.

Harvest's maximum exposure to credit risk relating to the above classes of financial assets at December 31, 2011 is the carrying value of accounts receivable. The table below provides an analysis of Harvest's current and past due but not impaired receivables.

	December 31, 2011				
			Overdue AR		
	Current AR	≤ 30 days	> 30 days, ≤ 60 days	> 60 days, ≤ 90 days	> 90 days
Upstream accounts receivable	$ 146,164	$ 1,286	$ 556	$ 1,168	$ 4,000
Downstream accounts receivable	50,660	6,155	1,702	206	355
	$ 196,824	**$ 7,441**	**$ 2,258**	**$ 1,374**	**$ 4,355[(1)]**

(1) Net of $3.3 million of allowance for doubtful accounts.

(ii.) Liquidity Risk

Harvest is exposed to liquidity risk due to the Company's borrowings under its credit facility, convertible debentures and $6^{7/8}$ % senior notes. This risk is mitigated by managing the maturity dates on the Company's obligations, complying with covenants and managing the Company's cash flow by entering into price risk management contracts. Additionally, when Harvest enters into price risk management contracts it selects counterparties that are also lenders in its syndicated credit facility thereby using the security provided in the credit agreement and eliminating the requirement for margin calls and the pledging of collateral.

In addition to the guarantee provided to Macquarie at December 31, 2011, Harvest has also provided guarantees of $15.8 million for Downstream product purchases.

The following table provides an analysis of Harvest's financial liability maturities based on the remaining terms of its liabilities as at December 31, 2011 and includes the related interest charges:

	December 31, 2011				
	≤1 year	>1 year ≤3 years	>3 years ≤5 years	>5 years	Total
Accounts payable and accrued liabilities	$ 464,148	$ –	$ –	$ –	$ 464,148
Bank loan and interest	5,643	11,287	360,756	–	377,686
Convertible debentures and interest	158,554	449,138	243,972	–	851,664
$6^{7/8}$ % senior notes and interest	34,959	69,919	69,919	534,720	709,517
Guarantees[(1)]	47,004	–	–	–	47,004
	$ 710,308	**$ 530,344**	**$ 674,647**	**$ 534,720**	**$2,450,019**

(1) Amounts are net of the related payables and receivables to and from counterparties.

(iii.) Market Risks and Sensitivity Analysis

Harvest is exposed to three types of market risks: interest rate risk, currency exchange rate risk and commodity price risk.

Harvest has performed sensitivity analysis on the three types of market risks identified, assuming that the volatility of the risks over the next year will be similar to that experienced in the past year. Harvest has determined that a reasonably possible price or rate variance over the next reporting period for a given risk variable can be estimated by calculating two standard deviations for each three month period in the last year for the relevant daily price/rate settings and using an average of the standard deviation as a reasonable estimate of the expected variance. This variance is then applied to the relevant period end rate or price to determine a reasonable percentage increase and decrease in the risk variable which can then be applied to the outstanding risk exposure at period end. Using twelve months of data, Harvest factors in the seasonality of the business and the price volatility therein.

<u>Interest rate risk</u>

Harvest is exposed to interest rate risk on its bank borrowings as interest rates are determined in relation to floating market rates plus an incremental charge based on the Company's secured debt to EBITDA. Harvest's convertible debentures and $6^{7/8}$ % senior notes have fixed interest rates and therefore do not have any additional interest rate risk. Harvest manages its interest rate risk by targeting appropriate levels of debt relative to its expected cash flow from operations.

If the interest rate applicable to Harvest's bank borrowings at December 31, 2011 increased or decreased by 25% with all other variables held constant, after-tax net income for the year would decrease by $0.1 million and increase by $0.9 million respectively as a result of change in interest expense on variable rate borrowing.

<u>Currency exchange rate risk</u>

Harvest is exposed to the risk of changes in the U.S. dollar exchange rate on its U.S. dollar denominated revenues as well as Canadian dollar revenues that are based on a U.S. dollar commodity price. In addition, Harvest's $6^{7/8}$ % senior notes are denominated in U.S. dollars (U.S.$500 million) and interest on these notes is payable semi-annually in U.S. dollars and accordingly the principal and any interest payable at the balance sheet date are also subject to currency exchange rate risk. Harvest's Downstream operations operate with a U.S. dollar functional currency which gives rise to currency exchange rate risk on the Company's Canadian dollar denominated monetary assets and liabilities such as Canadian dollar bank accounts and accounts receivable and payable. Harvest is also exposed to currency exchange rate risk on its net investment in its Downstream operations. Harvest manages these exchange rate risks by occasionally entering into fixed rate currency exchange contracts on future U.S. dollar payments and U.S. dollar sales receipts.

At December 31, 2011, if the U.S. dollar strengthened or weakened by 10% relative to the Canadian dollar, the impact on net income and other comprehensive income due to the translation of monetary financial instruments would be as follows:

	Increase (decrease) in Net Income	Increase (decrease) in Other Comprehensive Income
U.S. Dollar Exchange Rate - 10% increase	$ (19,870)	$ (34,754)
U.S. Dollar Exchange Rate - 10% decrease	$ 19,870	$ 34,754

(1) The sensitivity to net income and other comprehensive income is done independently.

Commodity Price Risk

Harvest is exposed to electricity and crude oil price movements as part of its normal business operations. The Company uses price risk management contracts to protect a portion of the Company's future cash flows and net income against unfavorable movements in commodity prices. These contracts are recorded on the consolidated statement of financial position at their fair value as of the reporting date. Changes from the prior period's fair value for electricity contracts are reported in net income. The effective portion of the changes from the prior period's fair value for crude oil contracts are reported in other comprehensive income. These fair values are generally determined as the difference between the stated fixed price of the contract and an expected future price of power and oil. Variances in expected future prices expose Harvest to commodity price risk as changes will result in a gain or loss that Harvest will realize on settlement of these contracts. This risk is mitigated by continuously monitoring the effectiveness of these contracts.

If the following changes in expected forward prices were applied to the fair value of risk management contracts, the pre-tax impact would be as follows:

December 31, 2011	Increase (decrease) in Net Income	Increase (decrease) in Other Comprehensive Income
Forward price of crude oil – 10% increase	$ (1,020)	$ (18,517)
Forward price of crude oil – 10% decrease	$ 621	$ 11,390

24. Segment Information

Harvest operates in Canada and has two reportable operating segments: Upstream and Downstream. Harvest's Upstream operations consist of development, production and subsequent sale of petroleum, natural gas and natural gas liquids, while its Downstream operations include the purchase of crude oil, the refining of crude oil, the sale of the refined products including a network of retail operations and the supply of refined products to commercial and wholesale customers.

	Year Ended December 31					
	Downstream		Upstream		Total	
	2011	2010	**2011**	2010	**2011**	2010
Petroleum, natural gas and refined products sales	**$3,239,455**	$3,105,957	**$1,286,866**	$ 1,007,004	**$4,526,321**	$4,112,961
Royalty	**-**	-	**(195,452)**	(154,757)	**(195,452)**	(154,757)
Revenues	**3,239,455**	3,105,957	**1,091,414**	852,247	**4,330,869**	3,958,204
Expenses						
Purchased products for resale and processing	**3,055,236**	2,893,805	–	–	**3,055,236**	2,893,805
Operating	**225,675**	215,640	**350,456**	265,593	**576,131**	481,233
Transportation and marketing	**6,293**	6,366	**29,626**	9,394	**35,919**	15,760
General and administrative	**1,764**	1,764	**60,804**	45,303	**62,568**	47,067

Exploration and evaluation	–	–	**18,289**	3,300	**18,289**	3,300
Depletion, depreciation and amortization	**91,006**	83,091	**535,692**	470,641	**626,698**	553,732
Gains on disposition of PP&E	–	–	**(7,883)**	(741)	**(7,883)**	(741)
Risk management contracts gains	–	–	**(6,746)**	(550)	**(6,746)**	(550)
Impairment on PP&E	–	–	–	13,661	–	13,661
	(140,519)	(94,709)	**111,176**	45,646	**(29,343)**	(49,063)
Finance costs					**109,127**	100,808
Foreign exchange gains					**(3,986)**	(3,399)
Loss before income tax					**(134,484)**	(146,472)
Income tax recovery					**(29,827)**	(65,309)
Net loss					**$ (104,657)**	$ (81,163)
Capital Expenditures						
Business acquisition	**$ –**	$ –	**$ 509,829**	$ 145,144	**$ 509,829**	$ 145,144
Additions to PP&E	**284,244**	71,234	**682,497**	356,851	**966,741**	428,085
Additions to E&E	–	–	**50,883**	46,997	**50,883**	46,997
Additions to other long term asset	–	–	**7,413**	–	**7,413**	–
Property acquisitions (dispositions), net	–	–	**(4,474)**	30,513	**(4,474)**	30,513
Total expenditures	**$ 284,244**	$ 71,234	**$1,246,148**	$ 579,505	**$1,530,392**	$ 650,739

(1) Of the total Downstream revenue, two customers represent sales of $1.5 billion and $586 million for the year ended December 31, 2011 (2010 - $2 billion and $145 million). No other single customer within either segment represents greater than 10% of Harvest's total revenue.

(2) There is no intersegment activity.

	Total Assets	PP&E	E&E	Other Long Term Assets	Goodwill
December 31, 2011					
Downstream	**$ 1,408,112**	**$ 1,222,512**	**$ –**	**$ –**	**$ –**
Upstream	**4,876,258**	**4,177,875**	**74,517**	**7,105**	**404,943**
Total	**$ 6,284,370**	**$ 5,400,387**	**$ 74,517**	**$ 7,105**	**$ 404,943**
December 31, 2010					
Downstream	$ 1,211,367	$ 1,003,384	$ –	$ –	$ –
Upstream	4,177,373	3,479,852	59,554	–	404,943
Total	$ 5,388,740	$ 4,483,236	$ 59,554	$ –	$ 404,943
January 1, 2010					
Downstream	$ 1,273,882	$ 1,113,742	$ –	$ –	$ –
Upstream	3,504,923	2,940,877	36,034		404,943
Total	$ 4,778,805	$ 4,054,619	$ 36,034	$ –	$ 404,943

25. Commitments and Contingencies

From time to time, Harvest is involved in litigation or has claims brought against it in the normal course of business operations. Management of Harvest is not currently aware of any claims or actions that would materially affect Harvest's reported financial position or results from operations. In the normal course of operations, management may also enter into certain types of contracts that require Harvest to indemnify parties against possible third party claims, particularly when these contracts relate to purchase and sale agreements. The terms of such contracts vary and generally a maximum is not explicitly stated; as such the overall maximum amount of the obligations cannot be reasonably estimated. Management does not believe payments, if any, related to such contracts would have a material effect on Harvest's reported financial position or results from operations.

The following are the significant commitments and contingencies at December 31, 2011:

Harvest entered into two contracts in relation to the engineering, procurement and construction ("EPC") of the production and processing facilities required for its BlackGold oil sands project in 2010 for a total contracted cost of $311 million. Harvest provided a cash deposit of $31.1 million in 2010, of which $24.9 million (2010 - $30.6 million) remains at December 31, 2011 to be applied to future payments. The remaining balances of the two contracts are included in the contractual obligation and commitment table below.

The Downstream operations have a supply and offtake agreement ("SOA") with Macquarie Energy Canada Ltd. ("Macquarie") for a primary term to October 31, 2012. This agreement provides that the ownership of substantially all crude oil feedstock and refined product inventory at the refinery be retained by Macquarie and that Macquarie has the right and obligation to provide crude oil feedstock for delivery to the refinery, as well as the right and obligation to purchase substantially all refined products produced by the refinery. As such, as at December 31, 2011, Downstream had commitments totaling approximately $776 million in respect of future crude oil feedstock purchases from Macquarie.

The following is a summary of Harvest's contractual obligations and commitments as at December 31, 2011:

	Payments Due by Period				
	1 year	2-3 years	4-5 years	After 5 years	Total
Debt repayments(1)	$ 106,796	$ 390,598	$ 595,464	$ 508,500	$ 1,601,358
Debt interest payments(1)	92,360	139,745	79,182	26,220	337,507
Purchase commitments(2)	207,207	48,409	1,143	-	256,759
Operating leases	9,368	15,267	2,187	564	27,386
Transportation agreements(3)	13,936	22,606	9,680	317	46,539
Feedstock and other purchase commitments(4)	776,092	-	-	-	776,092
Employee benefits(5)	4,534	7,828	4,944	3,837	21,143
Decommissioning liabilities(6)	12,782	58,989	33,805	1,343,584	1,449,160
Total	$1,223,075	$ 683,442	$ 726,405	$ 1,883,022	$ 4,515,944

(1) Assumes constant foreign exchange rate.
(2) Relates to drilling commitments, AFE commitments, BlackGold oil sands project commitment and Downstream capital commitments.
(3) Relates to firm transportation commitments.
(4) Includes commitments to purchase refinery crude stock and refined products for resale under the SOA with Macquarie.
(5) Relates to the expected contributions to employee benefit plans and long-term incentive plan payments.
(6) Represents the undiscounted obligation by period.

26. Related Party Transactions

Harvest's has a Global Technology and Research Centre ("GTRC"), is used as a training facility for KNOC personnel. For the year ended December 31, 2011, Harvest billed KNOC and certain subsidiaries for a total of

$1.6 million (2010 – $0.2 million) primarily related to technical services provided by the GTRC. As at December 31, 2011, $1.1 million (2010 - $0.1 million) remained outstanding from KNOC in accounts receivable. KNOC billed Harvest $0.6 million (2010 – $ nil) for reimbursement to KNOC for secondee salaries paid by KNOC on behalf of Harvest for the year ended December 31, 2011. As at December 31, 2011, $0.6 million (2010 - $nil) remains outstanding in accounts payable.

As at September 30, 2011, North Atlantic had committed to purchase $322.5 million of crude feedstock from KNOC, which Macquarie has taken over under the SOA.

On August 6, 2010, Harvest acquired the BlackGold oil sands project from KNOC for $374.2 million, representing the fair value of the oil and gas assets acquired. The acquisition was paid with the issuance of shares to KNOC. The following amounts were added to Harvest's statement of financial position at August 6, 2010 as a result of this transaction:

Current assets	$	500
Property, plant and equipment		374,182
Long-term liabilities		(10)
Decommissioning liabilities		(503)
Shareholder's capital	$	(374,169)

Directors and Key Management Personnel Remuneration

Key management personnel includes the Company's officers and other members of the executive management team. Included in the following table is remuneration to 5 (2010 – 9) independent directors and 15 (2010 – 14) key management personnel for the year ended December 31, 2011.

	Year Ended December 31			
		2011		2010
Salaries, wages and short-term employee benefits	**$**	**4,630**	$	5,248
Post-employment benefits		**49**		49
Other long-term benefits		**961**		989
	$	**5,640**	$	6,286

27. First Time Adoption of IFRS

IFRS 1 "First-time Adoption of International Financial Reporting Standards" establishes the transitional requirements for the preparation of financial statements upon first time adoption of IFRS. IFRS 1 generally requires an entity to comply with IFRS effective at the reporting date and to apply the standards retrospectively to the opening balance sheet, the comparative period and the reporting period. The standard allows certain optional exceptions from full retrospective application and other elections on transition, which the Company has applied as follows:

Business Combinations Exemption

The Company has applied the business combinations exemption in IFRS 1. It has not restated business combinations that took place prior to the January 1, 2010 transition date ("Transition Date").

Deemed Cost Election for Oil and Gas Assets

Under Canadian GAAP, the Company accounted for its oil and gas properties in one cost centre using full cost accounting. The Company elected to apply the exemption in IFRS 1 available to full cost oil and gas entities to its Upstream PP&E and measure its oil and gas properties at the Transition Date on the following basis:

- E&E assets at the amount determined under Canadian GAAP; and
- the remainder allocated to the underlying PP&E assets on a pro rata basis using proved and probable reserve values discounted at 10% at the Transition Date.

Fair Value as Deemed Cost Exemption

The Company elected to use the fair value as deemed cost exemption on its Downstream PP&E at the Transition Date.

Lease Exemption

The Company has elected to carry forward assessments made under Canadian GAAP for arrangements containing leases. The assessment of arrangements containing leases results in the same outcome under IAS 17 and IFRIC 4 "Determining whether an Arrangement contains a Lease".

Decommissioning Liabilities

Harvest has applied the deemed cost election for oil and gas assets under IFRS 1 and as such decommissioning liabilities at the Transition Date have been measured in accordance with IAS 37, "Provisions, Contingent Liabilities and Contingent Assets". The Company recognized directly in retained earnings any difference between the remeasured amount and the carrying amount of those liabilities at the Transition Date.

For the Downstream decommissioning liabilities, Harvest applied the exemption from full retrospective application of IAS 37 under IFRS 1. As such, the Company measured the decommissioning liabilities at the Transition Date, and recognized the corresponding charge in retained earnings.

Reconciliations of Canadian GAAP to IFRS

This is the first year that the Company has presented financial statements under IFRS; as such, the following reconciliations between Canadian GAAP and IFRS are included to provide an understanding of the material adjustments to the financial statements. The transition from Canadian GAAP to IFRS had no material effect upon previously reported cash flows. The following represents the reconciliations from Canadian GAAP to IFRS for the respective periods for shareholder's equity, net loss, and comprehensive loss.

Reconciliation of Shareholder's Equity

	Note	December 31, 2010	January 1, 2010
Shareholder's equity under Canadian GAAP		$ 3,250,943	$ 2,422,688
Decommissioning liabilities	a	(270,142)	(272,258)
Exploration and evaluation expenses	b		
Impairment of exploration and evaluation asset		(2,858)	-
Pre-licensing costs		(442)	-
Impairment of PP&E	c	(13,661)	-
Depletion, depreciation and amortization	d	(47,792)	-
Dispositions	e	335	-
Acquisitions	f		
Acquisition costs		(329)	-

BlackGold asset transfer		8,467	-
Gain on acquisition		406	-
Post-employment benefits	g	(2,765)	-
Deferred income taxes	h	94,283	69,083
Cumulative translation adjustments	i	440	-
Shareholder's equity under IFRS		$ 3,016,885	$ 2,219,513

Reconciliation of Net Loss

	Note	Year Ended December 31, 2010
Net loss under Canadian GAAP		$ (44,561)
Decommissioning liabilities	a	2,556
Exploration and evaluation expenses	b	
Unsuccessful exploration and evaluation costs		(2,858)
Pre-licensing costs		(442)
Impairment of PP&E	c	(13,661)
Depletion, depreciation and amortization	d	(47,792)
Dispositions	e	335
Acquisitions	f	
Acquisition costs		(329)
Gain on acquisition		406
Post-employment benefits	g	423
Deferred income taxes	h	25,200
Foreign currency translation	i	(440)
Total differences		(36,602)
Net loss under IFRS		$ (81,163)

Reconciliation of Other Comprehensive Loss

	Note	Year Ended December 31, 2010
Other comprehensive loss under Canadian GAAP		$ (51,380)
Post-employment benefits	g	(3,217)
Cumulative translation adjustments	i	440
Total differences		(2,777)
Other comprehensive loss under IFRS		(54,157)
Net loss under IFRS		(81,163)
Comprehensive loss under IFRS		$ (135,320)

The following adjustments were made to the consolidated statement of cash flows for the year ended December 31, 2010.

		Cash used in Operating Activities	Cash used in Investing Activities
Exploration and evaluation expenses	b	$ (442)	$ 442
Acquisition cost	f	(329)	329

There was no difference between Canadian GAAP and IFRS related to cash from financing activities.

<u>(a) Decommissioning liabilities</u>

The Company elected to apply the IFRS 1 exemption relating to decommissioning liabilities and re-measured decommissioning liabilities as at January 1, 2010 using the relevant risk-free rate. The exemption resulted in an increase of $272.3 million in decommissioning liabilities and a corresponding increase to deficit. This increase is mainly attributable to the change from the credit-adjusted risk-free rate to the risk-free rate of 4% for the Upstream decommissioning liabilities, resulting in an adjustment of $264.6 million. The recognition standards are different between Canadian GAAP and IFRS, which resulted in the recognition of the Downstream decommissioning liabilities of $7.7 million under IFRS on the Transition Date.

Under IFRS, the discount rate is adjusted each reporting period to reflect the current market risk-free rate. As at December 31, 2010, PP&E and the decommissioning liability were $68.8 million higher under IFRS.

As the opening decommissioning liabilities and the discount rates are different under IFRS, the accretion expense decreased by $2.6 million for the year ended December 31, 2010. There was minimal impact to the accretion due to the reduction of decommissioning liabilities resulting from the dispositions discussed under item (e).

(b) Exploration and evaluation costs

Unsuccessful exploration and evaluation costs

Under IFRS, Harvest capitalizes costs relating to exploration and evaluation activities until a project is determined to be successful or otherwise. If a project is deemed to be successful because it is technically feasible and commercially viable, then the costs are tested for impairment and transferred to property, plant and equipment. If a project is deemed to be unsuccessful, the associated costs are charged to the consolidated statement of income in the period as exploration and evaluation expense. During the year ended December 31, 2010, the Company recognized $2.9 million of exploration and evaluation expenses on certain unsuccessful E&E projects.

Pre-licensing costs

Under IFRS, costs incurred prior to obtaining the legal right to explore for oil and gas must be expensed while under Canadian GAAP these costs were capitalized in PP&E under one full-cost centre. For the year ended December 31, 2010, $0.4 million of pre-licensing costs were charged to the consolidated statement of income as exploration and evaluation expense. The accounting policy difference has resulted in a decrease in cash from operating activities and an increase in cash from investing activities by $0.4 million for the year ended December 31, 2010.

(c) CGU impairment

Under IFRS, impairment testing is performed at a lower level of asset aggregation than under Canadian GAAP. During the fourth quarter of 2010, Harvest recorded a $13.7 million before tax impairment related to certain properties in South Alberta to reflect declining forecasted gas prices which resulted in lower estimated future cash flows. The recoverable amount was based on the assets' value-in-use, estimated using the net present value of the expected future cash flows.

(d) Depletion, depreciation and amortization

Under IFRS, Harvest aggregates its PP&E into major components for depletion, depreciation and amortization. For the Upstream PP&E, costs accumulated within each component are depleted using the unit-of-production method based on estimated proved developed reserves, whereas under Canadian GAAP, estimated proved reserves were used. The carrying value of PP&E under IFRS differs from that under Canadian GAAP as a result of changes in the accounting of decommissioning liabilities and dispositions of

PP&E as discussed in items (a) and (e). Among these changes, the componentization of PP&E and the use of proved developed reserves for depletion primarily attributed to the recognition of additional $47.8 million of depletion, depreciation and amortization expense for the year ended December 31, 2010.

(e) Dispositions

Under Canadian GAAP, proceeds on the dispositions of PP&E were credited to the full cost pool and no gain or loss was recognized unless the effect of the sale would have changed the DD&A rate by 20% or more. Under IFRS, all gains and losses are recognized on oil and gas property divestitures and calculated as the difference between net proceeds and the carrying value of the net assets disposed. Accordingly, Harvest recognized a gain on PP&E disposal of $1.3 million for the year ended December 31, 2010 under IFRS. During the year ended December 31, 2010, Harvest also recognized a loss of $1.0 million relating to disposition of certain E&E assets.

(f) Acquisition

Acquisition costs

Under IFRS, acquisition costs relating to a business combination are expensed. As such, $0.3 million of acquisition costs were expensed for the year ended December 31, 2010. Under Canadian GAAP, such costs were capitalized as part of PP&E.

BlackGold asset transfer

Under IFRS, the transfer of BlackGold oil sand assets from KNOC in August 2010 is measured at the fair value of the assets and liabilities. Under Canadian GAAP, the assets and liabilities were transferred at the carrying value. The difference in the accounting treatment results in a reversal of an $8.5 million loss that was previously recognized in retained earnings and an increase of $8.5 million in PP&E.

Gain on acquisition

On September 30, 2010, Harvest purchased the remaining 40% of the Redearth Partnership (“Partnership”) as well as additional petroleum and natural gas rights, tangible assets, seismic data and other miscellaneous interests and associated production. Under IFRS, the acquirer is required to re-measure its previously held equity interest in the acquiree (the Partnership) at its acquisition-date fair value and recognize the resulting gain or loss, if any, in profit or loss; as such a gain of $0.4 million was recognized in the income statement relating to the 60% previously held interest in the Partnership for the year end December 31, 2010. Canadian GAAP did not require such re-measurement. See note 3 for other information on this asset acquisition.

(g) Post-employment benefits

Under Canadian GAAP, the Company amortized actuarial gains and losses to income over the estimated average remaining service life, with disclosure of the unrecognized amount in the notes to the consolidated financial statements. Under IFRS, actuarial gains and losses are recognized directly in other comprehensive income in the period in which they occur. For the year ended December 31, 2010, actuarial losses amortization of $0.4 million were reclassified to other comprehensive income from the net income. Together with the recognition of the unamortized actuarial losses, other comprehensive income was reduced by $3.2 million (net of deferred tax asset of $0.7 million) under IFRS.

(h) Deferred income taxes ("DIT")

IFRS requires recognition of the DIT asset or liability that arises on the difference between historical and current exchange rates on the translation of non-monetary assets, whereas Canadian GAAP did not. This difference, however, does not impact the DIT liability balance on transition date as the cumulative translation adjustments balance at transition date is $nil as a result of the KNOC acquisition. For the year ended December 31, 2010, the DIT expense decreased by $10.9 million.

As a result of the increase in the net book value of the decommissioning liabilities, the DIT effect has been adjusted. This resulted in a corresponding increase in retained earnings of $69.1 million on January 1, 2010.

The DIT expense decreased by $14.3 million for the year ended December 31, 2010, resulting from the increase in decommissioning liabilities and PP&E.

(i) Currency translation

Harvest's Downstream functional currency is U.S. dollars. As a result of the addition of the Downstream decommissioning liabilities in accordance with IAS 37, a currency exchange loss resulted from the revaluation of the liabilities at the end of each reporting period. For the year ended December 31, 2010 the amount of foreign exchange loss recognized was $0.4 million, which increased net loss and decreased other comprehensive loss.

Reclassifications

E&E and PP&E

Under Canadian GAAP, the Company had accounted for E&E and PP&E amounts under the full-cost method where these costs were included in PP&E. IFRS requires E&E costs to be segregated from PP&E.

As a result of the application of IFRS, the Company has separately classified E&E expenditures of $36.0 million from PP&E at the Transition Date. At December 31, 2010, $47.0 million, were reclassified. Note 6 discloses a reconciliation of E&E assets from the Transition Date to December 31, 2011.

Accretion of decommissioning liabilities

Accretion expense under Canadian GAAP has been reclassified from depreciation, depletion, amortization and accretion expense to finance costs under IFRS. The amount that was reclassified was $25.2 million for the year ended December 31, 2010.

Downstream loyalty program

Under Canadian GAAP, the Company had accounted for loyalty program costs by recording an expense. Under IFRS, the fair value of the consideration received or receivable in respect of the initial sale should be allocated between the award credits. As such, the Company has allocated the fair value of the consideration received from the sales to the award credits. This resulted in reclassifying $1.3 million of petroleum, natural gas, and refined product sales to Downstream operating expenses for the year ended December 31, 2010.

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (Unaudited)

The information below provides supplemental information on the oil and gas producing activities of the Corporation as of January 1, 2010, December 31, 2010 and 2011 and for the years ended December 31, 2010 and 2011 in accordance Financial Accounting Standards Board ("FASB") Statement of Accounting Standards No. 69 - *Disclosures about Oil and Gas Producing Activities* ("FAS 69"). Activities not directly associated with oil and gas producing activities are excluded from all aspects of this supplemental information.

Tables I through III present information on Harvest's estimated net proved reserve quantities; standardized measure of discounted future net cash flows, and changes in the standardized measure of discounted future net cash flows. Tables IV through VI provide historical cost information pertaining to result of operations related to oil and gas producing activities, capitalized costs related to oil and gas producing activities, and costs incurred in oil and gas exploration and development. Financial information included in tables IV through VI is derived from Harvest's audited annual financial statements which are prepared in accordance with IFRS.

Table I: Net Proved Reserves (Harvest's Share After Royalties)

Harvest's net proved oil and gas reserves as of January 1, 2010, December 31, 2010 and 2011, and changes thereto for the years ended December 31, 2010 and 2011 are shown in the following table. Note that all Harvest's proved reserves are located within Canada. Proved reserves as of the January 1, 2010, December 31, 2010 and 2011 were calculated using the average first-day-of-the-month oil and gas prices for the prior twelve-month period.

Proved oil and gas reserves, as defined within the SEC's Regulation S-X, are those quantities of oil and gas, which by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate.

Proved developed oil and gas reserves are proved reserves that can be expected to be recovered:

1. Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well; and
2. Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

The process of estimating proved and proved developed reserves is very complex and requires significant judgment in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may change significantly over time as a result of numerous factors, such as but not limited to, additional development activities, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Although reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, reserve estimates are subject to change as additional information becomes available, and as future economic and operating conditions change.

	Crude Oil and NGL	Bitumen	Natural Gas	Total

	(MMbbls)	(MMbbls)	(Bcf)	(MMBOE)
January 1, 2010	90.4	-	153.1	116.0
Revisions of previous estimates (including infill drilling & improved recovery)	9.7	-	18.9	12.8
Purchase of reserves in place	5.3	86.7	11.3	93.9
Sale of reserves in place	-	-	-	-
Discoveries and extensions	3.0	-	4.7	3.8
Production	(11.0)	-	(24.3)	(15.1)
December 31, 2010	97.4	86.7	163.7	211.4
Revisions of previous estimates (including infill drilling & improved recovery)	4.5	(4.5)	21.1	3.5
Purchase of reserves in place	5.9	-	107.3	23.8
Sale of reserves in place	-	-	-	-
Discoveries and extensions	5.3	-	24.9	9.4
Production	(12.2)	-	(36.6)	(18.3)
December 31, 2011	**100.9**	**82.2**	**280.4**	**229.8**
Proved Developed				
January 1, 2010	79.0	-	137.8	102.0
December 31, 2010	84.3	-	143.7	108.3
December 31, 2011	**88.3**	**-**	**226.6**	**126.0**
Proved Undeveloped				
January 1, 2010	11.4	-	15.3	14.0
December 31, 2010	13.1	86.7	20.0	103.1
December 31, 2011	**12.6**	**82.2**	**53.8**	**103.8**

Table II: Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following table provides the standardized measure of discounted future cash flows relating to the proved reserves disclosed in Table I above. Future cash inflows are computed using Harvest's after royalty share of estimated annual future production from proved oil and gas reserves and the average first-day-of-the-month oil and gas prices for the prior twelve-month period as prescribed by the SEC. Future development, production and abandonment costs to be incurred in producing and further developing the proved reserves are based on the costs at the balance sheet date and assuming continuation of existing economic conditions. Future income taxes are computed by applying year-end statutory tax rates to estimated future pre-tax net cash flows, less the tax basis of related assets. Discounted future net cash flows are calculated using 10% mid-period discount factors. This discounting requires a year-by-year estimate of when the future expenditure will be incurred and when the reserves will be produced.

The information provided in this table does not represent Harvest's estimate of the Corporation's expected future cash flows or the fair market value of the proved oil and gas reserves due to several factors including:

- Estimates of proved reserve quantities are subject to change as new information becomes available;
- Probable and possible reserves, which may become proved in the future, are excluded from the calculations;
- Future prices and costs rather than twelve-month average prices and costs at balance sheet date will apply;
- Economic conditions such as interest rates and income tax rates and operating conditions may differ from what is used in the preparation of the estimates; and
- Future development and asset decommissioning costs will differ from those estimated.

(thousands of Canadian dollars)		**December 31, 2011**		**December 31, 2010**		**January 1, 2010**
Future cash inflows	$	15,741,619	$	12,302,457	$	6,241,849
Less future:						
Production costs		(7,467,785)		(6,272,986)		(3,249,477)
Development costs		(1,664,733)		(1,503,936)		(364,839)
Decommissioning costs		(885,825)		(865,652)		(830,850)
Income taxes		(598,210)		(210,257)		-
Future net cash flows		5,125,066		3,449,626		1,796,683
Less 10% annual discount		(2,285,876)		(1,585,699)		(553,778)
Standardized measure of discounted future net cash flows	**$**	**2,839,190**	$	1,863,927	$	1,242,905

Table III: Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

(thousands of Canadian dollars)		**December 31, 2011**		**December 31, 2010**
Future discounted net cash flow, beginning of year	$	1,863,927	$	1,242,905
Sales & transfers of oil and gas produced, net of production costs		(711,332)		(577,260)
Net change in sales & transfer prices and production costs related to future production		616,785		566,000
Development costs incurred during the period		680,279		354,916
Change in future development costs		(658,367)		(429,126)
Change due to extensions and discoveries		176,717		84,300
Accretion of discount		233,997		159,495
Sales of reserves in place		-		-
Purchase of reserves in place		293,325		200,234
Net change in income taxes		(387,953)		(187,455)
Changes due to revisions in timing of future net cash flow and other		731,812		449,917
Future discounted net cash flow, end of year	**$**	**2,839,190**	$	1,863,926
Net change for the year	$	975,263	$	621,021

Table IV: Results of Operations

		Year Ended		
(thousands of Canadian dollars)		**December 31, 2011**		**December 31, 2010**
Petroleum and natural gas revenues, net of royalties	$	1,091,414	$	852,247
Less:				
Production costs		350,456		265,593
Exploration expense		18,289		3,300
Depletion, depreciation, and amortization(1)		533,425		470,688
Accretion of decommissioning liability		23,151		22,342
Impairment on oil and gas properties		-		13,661
Other (transportation and marketing costs)		29,626		9,394
Income tax expense(2)		29,681		9,049
Results of operations (excluding corporate overhead and interest costs)	**$**	**106,786**	$	58,220

(1) Excludes depreciation on corporate assets.

(2) Income tax expense has been calculated in accordance with FAS 69 using the statutory tax rate and reflecting tax deductions and credits and allowances relating to the oil and gas producing activities that are reflected in the consolidated income tax expense for the period.

Table V: Capitalized Costs

(thousands of Canadian dollars)	December 31, 2011	December 31, 2010	January 1, 2010
Proved oil and gas properties[(1)]	$ 5,180,432	$ 3,945,379	$ 2,936,446
Unproved oil and gas properties			
Unproven properties included in property, plant and equipment[(2)]	8,467	12,392	3,142
Exploration and evaluation assets	74,517	59,554	36,034
Total unproved oil and gas properties	82,984	71,946	39,176
Total capital costs	5,263,416	4,017,325	2,975,622
Accumulated depreciation, depletion and amortization ("DD&A")[(3)]	(1,015,540)	(482,422)	-
Net capitalized costs	**$ 4,247,876**	$ 3,534,903	$ 2,975,622

(1) Proved oil and gas properties exclude $8.7 million of corporate assets as at December 31, 2011 (December 31, 2010 - $6.4 million; January 1, 2010 - $1.3 million).

(2) Costs related to incomplete wells as at year end. As at December 31, 2011, Harvest was in the process of drilling a total of 10 gross wells (December 31, 2010 – 13 gross wells; January 1, 2010 – 4 gross wells).

(3) Accumulated DD&A excludes accumulated depreciation on corporate assets of $4.1 million as at December 31, 2011 (December 31, 2010 - $1.9 million; January 1, 2010 - $nil).

Table VI: Costs Incurred

	Year Ended	
(thousands of Canadian dollars)	December 31, 2011	December 31, 2010
Property acquisitions[(1)]		
Proved property	$ 495,456	$ 550,870
Unproved property	18,627	-
Total property acquisition costs	514,083	550,870
Exploration costs	50,883	46,997
Development costs	662,035	423,593
Total costs incurred[(2)]	**$ 1,227,001**	$ 1,021,460

(1) Property acquisition costs include business and property acquisitions and exclude proceeds received from dispositions of $8.7 million for the year ended December 31, 2011 (2010 - $1.0 million).

(2) Total costs incurred exclude costs related to corporate assets of $2.2 million for the year ended December 31, 2011 (2010 - $5.1 million).