U.S. SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 40-F

[ ] REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

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

For the fiscal year ended December 31, 2008 Commission File Number: **333-121627**

HARVEST ENERGY TRUST

(Exact name of Registrant as specified in its charter)

Alberta, Canada	1311	N/A
(Province or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification No.)*

Suite 2100
330 Fifth Avenue, S.W.
Calgary, Alberta, Canada T2P 0L4
(403) 265-1178
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System
111 Eighth Avenue
New York, New York 10011
(212) 894-8940

Name, address (including zip code) and telephone number (including area codes of agent for service)

Securities registered or to be registered pursuant to Section 12(b) of the Act

Title of Each Class	Name of each exchange on which registered
Trust Units	The New York Stock Exchange

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

For annual reports, indicate by check mark the information filed with this Form:

[X] Annual information form [X] Audited annual financial statements

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:

157,200,701 Trust Units

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the filing number assigned to the Registrant in connection with such Rule.

Yes____ No __X__

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act 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__X__ No ____

FORM 40-F

Principal Documents

The following documents have been filed as part of this annual report on Form 40-F:

(a) Annual Information Form for the fiscal year ended December 31, 2008;

(b) Management's Discussion and Analysis for the fiscal year ended December 31, 2008; and

(c) Consolidated Financial Statements for the fiscal year ended December 31, 2008 *(Note 23 to the Consolidated Financial Statements relates to United States Accounting Principles and Reporting (U.S. GAAP)).*

FORWARD-LOOKING STATEMENTS

This annual report on Form 40-F contains or incorporates by reference forward-looking statements relating to future events or future performance including forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. For a full description of forward-looking information, readers should review the disclosure under the heading “Special Note Regarding Forward Looking Statements” at pages 10 and 11 in the Registrant’s Annual Information Form for the year ended December 31, 2008, which is part of this annual report on Form 40-F and is incorporated by reference herein.

HARVEST ENERGY TRUST

ANNUAL INFORMATION FORM

For the year ended December 31, 2008

MARCH 27, 2009

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GLOSSARY OF TERMS

In this Annual Information Form, the following terms shall have the meanings set forth below, unless otherwise indicated.

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

"**Administration Agreement**" means the agreement dated September 27, 2002 between the Trustee and Harvest Operations pursuant to which Harvest Operations provides certain administrative and advisory services in connection with the Trust. See "General Description of Capital Structure".

"**Affiliate**" means, with respect to the relationship between corporations, that one of them is controlled by the other or that both of them are controlled by the same Person and for this purpose a corporation shall be deemed to be controlled by the Person who owns or effectively controls, other than by way of security only, sufficient voting shares of the corporation (whether directly through the ownership of shares of the corporation or indirectly through the ownership of shares of another corporation or otherwise) to elect the majority of its board of directors.

"**Birchill**" means Birchill Energy Limited, a private company which, at the date of its acquisition by Harvest owned certain petroleum and natural gas properties which are described in "General Development of the Business - Year ended December 31, 2006".

"**Board of Directors**" or "**Harvest Board**" means the board of directors of Harvest Operations.

"**BRP**" means Breeze Resources Partnership, a general partnership formed under the laws of Alberta.

"**Business Day**" means a day, other than a Saturday, Sunday or statutory holiday in the Province of Alberta or any other day on which banks in Calgary, Alberta are not open for business.

"**CNG Trust**" means Calpine Natural Gas Trust, a trust organized under the laws of the Province of Alberta, wholly owned by the Trust.

"**COGPE**" means Canadian oil and natural gas property expense, as defined in the Tax Act.

"**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.

"**Credit Facility**" or "**Extendible Revolving Credit Facility**" means the credit facility provided by the Current Lenders as more fully described in Note 10 to Harvest's audited consolidated financial statements for the year ended December 31, 2008 filed on www.sedar.com.

"**Current Lenders**" means the syndicate of lenders to Harvest Operations pursuant to the current Credit Facility.

"**Debentures**" means, collectively, the 10.5% Debentures Due 2008, the 9% Debentures Due 2009, the 8% Debentures Due 2009, the 6.5% Debentures Due 2010, the 6.40% Debentures Due 2012, the 7.25% Debentures Due 2013, the 7.25% Debentures Due 2014 and the 7.5% Debentures Due 2015.

"**Debenture Indenture**" means, collectively, the trust indenture dated January 29, 2004, a first supplemental indenture dated August 10, 2004, a second supplemental indenture dated August 2, 2005, a third supplemental indenture dated November 22, 2006, a fourth supplemental indenture dated February 1, 2007, and a fifth supplemental indenture dated April 25, 2008 among the Trust, Harvest Operations and Valiant Trust Company and the trust indenture dated January 15, 2003 and a supplemental indenture dated October 20, 2005 between VERT and Computershare Trust Company of Canada.

"**Debenture Trustee**" means, as applicable, the trustee of the 9% Debentures Due 2009, 8% Debentures Due 2009, 6.5% Debentures Due 2010, 7.25% Debentures Due 2013, 7.25% Debentures Due 2014, and 7.5% Debentures Due 2015 , Valiant Trust Company or the trustee of the 10.5% Debentures due 2008 and the 6.40% Debentures due 2012, Computershare Trust Company of Canada.

"**10.5% Debentures Due 2008**" means the 10.5% convertible unsecured subordinated debentures of the Trust due January 31, 2008 assumed on February 3, 2006 pursuant to the terms of the Viking Arrangement.

"**9% Debentures Due 2009**" means the 9% convertible unsecured subordinated debentures of the Trust due May 31, 2009.

"**8% Debentures Due 2009**" means the 8% convertible unsecured subordinated debentures of the Trust due September 30, 2009.

"**6.5% Debentures Due 2010**" means the 6.5% convertible unsecured subordinated debentures of the Trust due December 31, 2010.

"**6.40% Debentures Due 2012**" means the 6.40% convertible unsecured subordinated debentures of the Trust due October 31, 2012 assumed on February 3, 2006 pursuant to the terms of the Viking Arrangement.

"**7.25% Debentures Due 2013**" means the 7.25% convertible unsecured subordinated debentures of the Trust due September 30, 2013 issued on November 22, 2006.

"**7.25% Debentures Due 2014**" means the 7.25% convertible unsecured subordinated debentures of the Trust due February 28, 2014 issued on February 1, 2007 and February 8, 2007.

"**7.50% Debentures Due 2015**" means the 7.50% convertible unsecured subordinated debentures of the Trust due May 31, 2015 issued on April 25, 2008.

"**$7^{7/8}$% Senior Notes**" means the $7^{7/8}$% Senior Notes of Harvest Operations due October 15, 2011 unconditionally guaranteed by the Trust.

"**Deferred Purchase Price Payment**" or "**DPPP**" means, collectively, the ongoing obligation of the Trust to pay to Harvest Operations, and HBT2, to the extent of the Trust's available funds, an amount up to 99% of the cost of, including any amount borrowed to acquire, any Canadian resource property acquired by Harvest Operations, or HBT2, and the cost of, including any amount borrowed to fund, certain designated capital expenditures in relation to the Properties.

"**Direct Royalties**" means royalty interests in petroleum and natural gas rights acquired by the Trust from time to time pursuant to a Direct Royalties Sale Agreement.

"**Direct Royalties Sale Agreement**" means any purchase and sale agreement between the Trust and an Operating Subsidiary providing for the purchase by the Trust from an Operating Subsidiary of Direct Royalties.

"**Downstream**" means our 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 64 gasoline outlets, a retail heating fuels business and a commercial and wholesale petroleum products business, all located in the Province of Newfoundland and Labrador.

"**DRIP Plan**" means the Trust's Premium Distribution™, Distribution Reinvestment and Optional Trust Unit Purchase Plan.

"**East Central Alberta Properties**" means Properties located in the East Central Alberta region.

"**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.

"**GLJ**" means GLJ Petroleum Consultants Ltd., independent oil and natural gas reservoir engineers of Calgary, Alberta.

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

"**Grand**" means Grand Petroleum Inc, a public company which, at the date of its acquisition by Harvest owned certain petroleum and natural gas properties which are described in "General Development of the Business - Year ended December 31, 2007".

"**Gross**" means:

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

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

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

"**Harvest**" means, collectively, the Trust and its subsidiaries, trusts and partnerships.

"**Harvest Operations**" means the Trust's wholly owned subsidiary, Harvest Operations Corp.

"**HBT1**" or "**Breeze Trust No. 1**" means Harvest Breeze Trust 1, a trust established under the laws of the Province of Alberta, wholly owned by the Trust.

"**HBT2**" or "**Breeze Trust No. 2**" means Harvest Breeze Trust 2, a trust established under the laws of the Province of Alberta, wholly owned by the Trust.

"**HRGP**" means Harvest Refining General Partnership, a general partnership established under the laws of the Province of Alberta, owned 99% by the Trust and 1% by CNG Trust

"**Independent Reserve Engineering Evaluators**" means McDaniel and GLJ, independent oil and natural gas reservoir engineers of Calgary, Alberta, who evaluated the crude oil, natural gas liquids and natural gas reserves of the Operating Subsidiaries as at December 31, 2008, in accordance with the standards contained in the COGE Handbook and the reserve definitions and other requirements contained in NI 51-101.

"**McDaniel**" means McDaniel & Associates Consultants Ltd., independent oil and natural gas reservoir engineers of Calgary, Alberta.

"**Net**" means:

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

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

(c) in relation to the Operating Subsidiaries' interest in a property, the total area in which the Operating Subsidiaries have an interest multiplied by the working interest owned by 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, acquired by Harvest on October 19, 2006.

"**North Atlantic Acquisition**" means the acquisition of all of the shares of North Atlantic and related businesses and the entering into of the Supply and Offtake Agreement in accordance with the Purchase and Sale Agreement, which transactions were completed on October 19, 2006.

"**NPI**" means, collectively, the net profit interest owing to the Trust pursuant to the NPI Agreements.

"**NPI Agreements**" means, collectively the agreements between Harvest Operations and the Trust, and between HBT1 and the Trust to pay net profit interests to the Trust.

"**NYMEX**" means the New York Mercantile Exchange.

"**NYSE**" means the New York Stock Exchange.

"**Operating Subsidiaries**" means, collectively, Harvest Operations, REP, BRP, HBT1, HBT2, Hay River Partnership, and HRGP (and all direct and indirect wholly-owned subsidiaries of HRGP), each a direct or indirect wholly-owned subsidiary of the Trust other than REP in respect of which the Trust, indirectly, holds a 60% interest, and "**Operating Subsidiary**" means any of Harvest Operations, REP, BRP, HBT1, HBT2, Hay River Partnership or HRGP (or any direct or indirect wholly-owned subsidiary of HRGP, as applicable).

"**Ordinary Resolution**" means a resolution approved at a meeting of Unitholders by more than 50% of the votes cast in respect of the resolution by or on behalf of Unitholders present in person or represented by proxy at the meeting.

"**Ordinary Trust Units**" means the Ordinary Trust Units of the Trust created, issued, and certified under the Trust Indenture and for the time being outstanding and entitled to the benefits thereof.

"**Permitted Investments**" means:

(a) loan advances to Harvest Operations;

(b) interest bearing accounts of certain financial institutions including Canadian chartered banks and the Trustee;

(c) obligations issued or guaranteed by the Government of Canada or any province of Canada or any agency or instrumentality thereof;

(d) term deposits, guaranteed investment certificates of deposit or bankers' acceptances of or guaranteed or accepted by any Canadian chartered bank or other financial institution (including the Trustee and any Affiliate of the Trustee) the short term debt or deposits of which have been rated at least A or the equivalent by Standard & Poor's Corporation or Moody's Investors Service, Inc. or Dominion Bond Rating Service Limited;

(e) commercial paper rated at least A or the equivalent by Dominion Bond Rating Service Limited; and

(f) investments in bodies corporate, partnerships or trusts engaged in the oil and natural gas business, including the Operating Subsidiaries;

provided that an investment is not a Permitted Investment if it:

(g) would result in the cost amount to the Trust of all "foreign property" (as defined in the Tax Act) which is held by the Trust to exceed the amount prescribed by Regulation 5000(1) of the Regulations to the Tax Act;

(h) is a "small business security" as that term is used in Part L1 of the Regulations to the Tax Act; or

(i) would result in the Trust not being considered either a "unit trust" or a "mutual fund trust" for purposes of the Tax Act.

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

"**Pro Rata Share**" means, of any particular amount in respect of a Unitholder at any time, the product obtained by multiplying the number of Trust Units that are owned by that Unitholder at that time by the quotient obtained when the particular amount is divided by the total number of all Trust Units that are issued and outstanding at that time.

"**Production**" means the produced petroleum, natural gas and natural gas liquids attributed to the Properties.

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

"**Property Interests**" means petroleum and natural gas rights and related tangibles and miscellaneous interests beneficially owned by the Operating Subsidiaries.

"**Purchase and Sale Agreement**" means the purchase and sale agreement dated August 22, 2006 between the Trust 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.

"**Record Date**" means December 31 of each year hereafter and the last day of each calendar month or such other date as may be determined from time to time by the Trustee upon the recommendation of the Board of Directors.

"**Redearth Partnership**" or "**REP**" means Redearth Partnership, a partnership established under the laws of the Province of Alberta, a 60% interest of which is owned by Harvest Operations.

"**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, which is described in "Downstream Business".

"**Reserve Account**" means the cumulative amount of production and other revenues entitled to be retained by the Operating Subsidiaries pursuant to the NPI Agreements to provide for payment of production costs which the Operating Subsidiaries estimate will or may become payable in the following six months for which there may not be sufficient production revenues to satisfy such production costs in a timely manner. See "Structure of Harvest Energy Trust – Net Profits Interest Agreements".

"**Reserve Life Index**" or "**RLI**" means the amount obtained by dividing the quantity of proved plus probable reserves as at December 31, 2008, by the annualized production of petroleum, natural gas and natural gas liquids from those reserves in 2008.

"**Reserve Report**" means, collectively, the reports prepared by the Independent Reserve Engineering Evaluators evaluating the crude oil, natural gas liquids and natural gas reserves of the Operating Subsidiaries as at

December 31, 2008, in accordance with the standards contained in the COGE Handbook and the reserve definitions and other requirements contained in NI 51-101.

"**Reserve Value**" means, for any petroleum and natural gas property at any time, the present worth of all of the estimated pre-tax cash flow net of capital expenditures from the proved plus probable reserves shown in the Reserve Report for such property, discounted at 10% and using forecast price and cost assumptions (a common benchmark in the oil and natural gas industry).

"**Special Trust Units**" means the Special Trust Units of the Trust created, issued, and certified under the Trust Indenture and for the time being outstanding and entitled to the benefits thereof. There are no Special Trust Units currently outstanding.

"**Special Voting Units**" means the Special Voting Units of the Trust created, issued, and certified under the Trust Indenture and for the time being outstanding and entitled to the benefits thereof. There are no Special Voting Units currently outstanding.

"**Special Resolution**" means a resolution proposed to be passed as a special resolution at a meeting of Unitholders (including an adjourned meeting) duly convened for the purpose and held in accordance with the provisions of the Trust Indenture at which two or more holders of at least 10% of the aggregate number of Trust Units then outstanding are present in person or by proxy and passed by the affirmative votes of the holders of not less than 66 2/3% of the Trust Units represented at the meeting and voted on a poll upon such resolution.

"**Subsequent Investments**" means any of the investments that the Trust may make pursuant to the Trust Indenture, which includes:

(a) making payments to Harvest Operations pursuant to the Deferred Purchase Price Obligations under the NPI Agreement with Harvest Operations;

(b) making loans to Harvest Operations in connection with the Capital Fund; and

(c) temporarily holding cash and investments for the purposes of paying the expenses and liabilities of the Trust, making certain other investments as contemplated by Section 4.2 of the Trust Indenture, paying amounts payable by the Trust in connection with the redemption of any Trust Units, and making distributions to Unitholders;

provided that such investments will not be a Subsequent Investment if it:

(d) would result in the cost amount to the Trust of all "foreign property" (as defined in the Tax Act) which is held by the Trust to exceed the amount prescribed by Regulation 5000(1) of the Regulations to the Tax Act;

(e) is a "small business security" as that term is used in Part L1 of the Regulations to the Tax Act; or

(f) would result in the Trust not being considered either a "unit trust" or a "mutual fund trust" for purposes of the Tax Act.

"**Supply and Offtake Agreement**" or "**SOA**" means the supply and offtake agreement dated October 19, 2006 entered into between North Atlantic and Vitol Refining, S.A., a wholly-owned subsidiary of the vendor to the North Atlantic Acquisition, the terms of which are summarized under the "Downstream Business – Supply and Offtake Agreement".

"**Tax Act**" means the *Income Tax Act* (Canada) and the regulations thereunder.

"**Trust**" means Harvest Energy Trust.

"**Trust Fund**" at any time, shall mean any of the following monies, properties and assets that are at such time held by the Trustee on behalf of the Trust for the purposes of the Trust under the Trust Indenture:

(a) the amount paid to settle the Trust;

(b) all funds realized from the issuance of Trust Units;

(c) any Permitted Investments in which funds may from time to time be invested;

(d) all rights in respect of and income generated under the NPI Agreement with Harvest Operations, including the applicable NPI;

(e) all rights in respect of and income generated under a Direct Royalties Sale Agreement;

(f) any Subsequent Investment;

(g) any proceeds of disposition of any of the foregoing property including, without limitation, the Direct Royalties; and

(h) all income, interest, profit, gains and accretions and additional assets, rights and benefits of any kind or nature whatsoever arising directly or indirectly from or in connection with or accruing to such foregoing property or such proceeds of disposition.

"**Trust Indenture**" means the fifth amended and restated trust indenture dated May 20, 2008 between the Trustee and Harvest Operations as such indenture may be further amended by supplemental indentures from time to time.

"**Trust Unit**" means a trust unit of the Trust and unless the context otherwise requires means Ordinary Trust Units.

"**Trustee**" means Valiant Trust Company, or its successor as trustee of the Trust.

"**TSX**" means the Toronto Stock Exchange.

"**Unitholders**" means the holders from time to time of one or more Trust Units.

"**Upstream**" means our petroleum and natural gas segment, consisting of the development, production and subsequent sale of petroleum, natural gas and natural gas liquids in Alberta, Saskatchewan and British Columbia.

"**U.S. Securities Act**" means the *United States Securities Act of 1933*, as amended.

"**VERT**" means Viking Energy Royalty Trust, an open-ended, unincorporated investment trust established under the laws of the Province of Alberta on November 5, 1996 pursuant to a trust indenture dated November 5, 1996 as amended and restated effective February 3, 2006.

"**Viking**" means, collectively, VERT and its subsidiaries, trusts and partnerships.

"**VHI**" or "**Viking Holdings**" means Viking Holdings Inc., a corporation incorporated under the ABCA by VERT on August 13, 1997 and which amalgamated with Harvest Operations on July 1, 2006, with the amalgamated corporation continuing under the name "Harvest Operations Corp.".

"**Viking Arrangement**" means the Plan of Arrangement involving Harvest, Harvest Operations, VERT, VHI, Harvest securityholders and Viking unitholders as approved by the Harvest securityholders and the Viking unitholders on February 2, 2006 and effective February 3, 2006.

"**Working Interest**" or "**WI**" 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.

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

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
bbls	barrels
Mbbls	thousand barrels
bbls/d	barrels per day
MMbbls	million barrels
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMBTU	million British Thermal Units
GJ	gigajoule

Other

AECO	Carlyle/Riverstone Global Energy and Power Fund’s natural gas storage facility located at Suffield, Alberta.
ASP	alkaline surfactant polymer.
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.
BOE/d	barrels of oil equivalent per day.
EOR	enhanced oil recovery.
MBOE	thousand barrels of oil equivalent.
MMBOE	million barrels of oil equivalent.
OOIP	original oil in place.
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade.
ºAPI	The measure of the density or gravity of liquid petroleum products derived from a specific gravity.
MW	megawatts of electrical power.
3D	three dimensional.
Darcies	the measure of permeability (being the ease with which a single fluid will flow through connected pore space when a pressure gradient is applied).
Porosity	The measure of the fraction of pore space of a reservoir.
$000	thousands of dollars.
$millions	millions of dollars.

CONVERSIONS

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

EXCHANGE RATE INFORMATION

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

The following table sets forth for each period indicated, the average, high, low and end of period noon buying rates in New York for cable transfers as certified for customs purposes by the Federal Reserve Bank of New York (the "noon buying rate"). Such rates are set forth as U.S. dollars per $1.00 and are the inverse of the rates quoted by the Federal Reserve Bank of New York for Canadian dollars per US$1.00.

	Year Ended December 31,		
	2008	2007	2006
High	1.0289	1.0905	0.9099
Low	0.7711	0.8437	0.8528
Period End	0.8166	1.0120	0.8581
Average (1)	0.9332	0.9376	0.8846

Note:

(1) Average represents the average of the rates on the last day of each month during the period.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form 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 "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. Harvest Operations 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 Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In particular, this Annual Information Form, and the documents incorporated by reference herein, contain forward-looking statements pertaining to:

- expected financial performance in future periods;
- expected increases in revenue 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;
- emphasis on having a low cost structure;
- intention to retain a portion of cash flows after distributions to repay indebtedness and invest in further development of our properties;
- reserve estimates and estimates of the present value of our future net cash flows;
- methods of raising capital for exploitation and development of reserves;
- factors upon which to decide whether or not to undertake a development or exploitation project;
- plans to make acquisitions and expected synergies from acquisitions made;
- expectations regarding the development and production potential of petroleum and natural gas properties;

- treatment under government regulatory regimes including without limitation, environmental and tax regulation;
- 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 Information Form 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;
- 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:

- 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;
- 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;
- 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 Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. Except as required by law, neither the Trust nor Harvest Operations undertakes any obligation to publicly update or revise any forward-looking statements and readers should also carefully consider the matters discussed under the heading "Risk Factors" in this Annual Information Form.

NON-GAAP MEASURES

Harvest uses certain financial reporting measures that are commonly used as benchmarks within the petroleum and natural gas industry. These measures include: "Payout Ratio", "Cash G&A", "Operating Netbacks", “Earnings from

Operations" and "Gross Margin". These measures are not defined under Canadian generally accepted accounting principles and should not be considered in isolation or as an alternative to conventional Canadian GAAP measures. Certain of these measures are not necessarily comparable to a similarly titled measure of another company or trust. When these measures are used, they have been footnoted and the footnote to the applicable measure notes that the measure is "non-GAAP" and contains a description of how to reconcile the measure to the applicable financial statements. These measures should be given careful consideration by the reader.

Specifically, management uses Payout Ratio, Cash G&A and Operating Netbacks as they are non-GAAP measures used extensively in the Canadian energy trust sector for comparative purposes. Payout Ratio is the ratio of distributions to total Cash from Operating Activities. Operating Netbacks are always reported on a per BOE basis, and include gross revenue, royalties, transportation and operating expenses. Cash G&A are G&A expenses, excluding the effect of unit based compensation plans. Gross Margin is also a non-GAAP measure commonly used in the refining industry to reflect the net cash received from the sale of refined product after considering the cost to purchase the feedstock and is calculated by deducting purchased products for resale and processing from total revenue. Earnings from Operations is also a non-GAAP measure commonly used in the petroleum and natural gas and in the refining and marketing industries to reflect operating results before items not directly related to operations.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Trust's most recently completed financial year, being the year ended December 31, 2008.

STRUCTURE OF HARVEST ENERGY TRUST

Harvest Energy Trust

Harvest Energy Trust is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta on July 10, 2002 pursuant to the Trust Indenture between Harvest Operations, a wholly owned subsidiary and administrator of the Trust, and Valiant Trust Company as Trustee. The Trust Indenture has been amended from time to time, the latest material amendments being approved effective May 20, 2008. The Trust's assets consist of securities, unsecured debt and net profits interests on the oil and natural gas assets of several direct and indirect subsidiaries, trusts and partnerships. The Trust is managed by Harvest Operations pursuant to the Administration Agreement.

The head and principal office of the Trust and Harvest Operations is located at Suite 2100, 330 - 5th Avenue S.W., Calgary, Alberta T2P 0L4 while the registered office of Harvest Operations is located at Suite 1400, 350 – 7th Avenue S.W., Calgary, Alberta T2P 3N9.

The beneficiaries of the Trust are the holders of its Trust Units who receive distributions from the Trust's net cash flow from its various investments after certain administrative expenses and the provision for interest due to the holders of convertible debentures. Pursuant to the Trust Indenture, the Trust is required to distribute 100% of its taxable income to its Unitholders each year and its activities are limited to holding and administering permitted investments and making distributions to its Unitholders.

The business of the Trust is to, indirectly through Harvest Operations and its other Operating Subsidiaries, exploit, develop and hold interests in petroleum and natural gas properties in its upstream segment as well as conduct petroleum refining and marketing operations in its downstream segment. The activities of the Operating Subsidiaries are financed through interest bearing notes from the Trust, the purchase of NPIs by the Trust and third party debt.

Cash from the upstream operations flows to the Trust by way of payments by Harvest Operations and Breeze Trust No. 1 pursuant to NPIs held by the Trust, interest and principal payments by Harvest Operations, Breeze Trust No. 1 and Breeze Trust No. 2 on unsecured debt owing to the Trust and payments by Breeze Trust No. 1 and Breeze Trust No. 2 of trust distributions. Cash flow from the downstream operations flows to the Trust in the form of interest and principal on unsecured debt owing to the Trust from North Atlantic Refining Limited as well as partnership distributions from Harvest Refining General Partnership.

Operating Subsidiaries

Harvest Operations Corp., a taxable corporation

Harvest Operations was incorporated under the ABCA on May 14, 2002. Subsequently, Harvest Operations has been amalgamated with numerous wholly-owned corporate subsidiaries and continued as "Harvest Operations Corp." All of the issued and outstanding common shares of Harvest Operations are held for the benefit of the Trust.

In addition to administering the affairs of the Trust, Harvest Operations manages the affairs of the other Operating Subsidiaries 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.

Redearth Partnership, a general partnership

Redearth Partnership is a general partnership formed on August 23, 2002 under the laws of the Province of Alberta. In June 2004, Harvest Operations acquired its 60% ownership interest in Redearth Partnership. Redearth Partnership's assets consist of direct ownership interest in properties located in north central Alberta.

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 the Trust 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 and a 99% interest in each of those partnerships.

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 the Trust and its assets consist of a 1% interest in each of the Breeze Resources Partnership and the Hay River Partnership.

Breeze Resource Partnership, a general partnership

Breeze Resource Partnership (indirectly wholly-owned by the Trust) is a general partnership formed on June 30, 2004 under the laws of the Province of Alberta. Breeze Resource 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 and a promissory note due from Harvest Breeze Trust No. 1.

Hay River Partnership, a general partnership

Hay River Partnership (indirectly wholly-owned by the Trust) 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 and a promissory note due from Harvest Breeze Trust No. 1.

Harvest Refining General Partnership, a general partnership

Harvest Refining General Partnership is a wholly-owned general partnership formed on September 27, 2006 under the laws of the Province of Alberta. The Trust holds a 99% partnership interest and CNG Trust holds the residual 1% partnership interest. Harvest Refining General Partnership's assets consist of unsecured debt owing from each of VERT and North Atlantic as well as a 100% equity interest in both VERT and North Atlantic.

North Atlantic Refining Limited, a taxable corporation

Harvest North Atlantic Acquisition Corp (a wholly-owned subsidiary of Harvest Refining General Partnership incorporated on September 21, 2006 to acquire North Atlantic Refining Limited) amalgamated with North Atlantic Refining Limited pursuant to The Corporations Act of the Province of Newfoundland and Labrador on October 19, 2006 and continued as "North Atlantic Refining Limited". North Atlantic's assets consist of preferred partnership units representing 75% of the total preferred partnership interest in the North Atlantic Refining Limited Partnership as well as common partnership units representing 5% of the total common partnership interest in the same partnership.

North Atlantic manages the affairs of North Atlantic Refining Limited Partnership and is responsible for providing the engineering, operations and administrative services related to Harvest's refining operations. The feedstock supply management and marketing of refined products has been contracted to Vitol Refining, S.A. pursuant to the Supply and Offtake Agreement.

Viking Energy Royalty Trust, a commercial trust

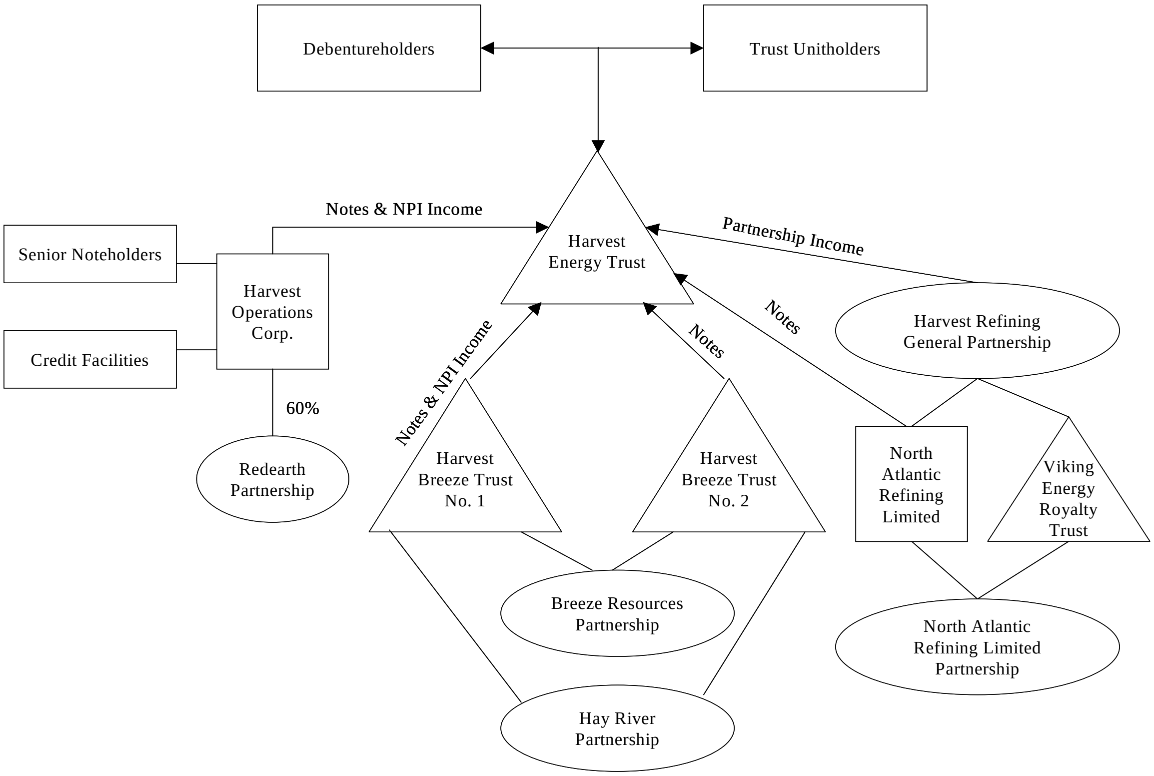
Viking Energy Royalty Trust (indirectly, wholly-owned by the Trust) is a trust established under the laws of the Province of Alberta on November 5, 1996. VERT's assets consist of preferred partnership units representing 25% of the total preferred partnership interest in the North Atlantic Refining Limited Partnership as well as common partnership units representing 95% of the total common partnership interest in the same partnership.

North Atlantic Refining Limited Partnership, a limited partnership

North Atlantic Refining Limited Partnership (a partnership wholly-owned by North Atlantic Refining Limited and Viking Energy Royalty Trust) is a limited partnership formed on October 13, 2006 under the laws of the Province of Newfoundland and Labrador. North Atlantic Refining Limited Partnership's assets consist of the Refinery and related retail marketing assets.

Organizational Structure of the Trust

The structure of the Trust and its significant subsidiaries including the flow of cash from Harvest's upstream and downstream operations through to the Unitholders and the holders of Debentures is set forth below**:**



Notes:

(1) All operations and management of the Trust and the Trust's Operating Subsidiaries are conducted through Harvest Operations except for the operations of the North Atlantic Refining Limited Partnership which is conducted by the management and employees of North Atlantic Refining Limited.

(2) The Trust receives regular monthly net profits interest payments and/or interest payments from Harvest Operations, Breeze Trust No. 1, Harvest Breeze Trust No. 2 and North Atlantic Refining Limited and distributions from Harvest Breeze Trust No. 1, Harvest Breeze Trust No. 2, and Harvest Refining General Partnership.

(3) Breeze Trust No. 1 and Breeze Trust No. 2 have also issued priority trust units to HOC.

The Net Profits Interest Agreements

Pursuant to each NPI Agreement, the Trust is entitled to monthly payments equal to 99% of the amount by which the gross proceeds from the sale of production attributable to Property Interests for such month exceed certain deductible expenditures. Deductible expenditures may include discretionary amounts to fund capital expenditures, to repay third party debt and to provide for working capital required to maintain the operations of the Operating Subsidiaries. The residual 1% share which does not form part of the NPI is retained by the Operating Subsidiaries. The NPI Agreements result in substantially all of the economic benefit derived from the Property Interests of the Operating Subsidiaries accruing to the benefit of the Trust and ultimately to the Unitholders. The term of each NPI Agreement is for so long as there are petroleum and natural gas rights to which the net profits interest agreement applies.

To the extent the Trust has available funds, the NPI Agreements also establish an ongoing obligation for the Trust to pay a Deferred Purchase Price Payment to the Operating Subsidiaries in an amount equal to the sum of the following less amounts financed by the Operating Subsidiaries:

(a) acquisition costs incurred by the Operating Subsidiary attributable to Canadian resource property; plus

(b) certain designated drilling, completion, equipping and other costs, in respect of the Properties; plus

(c) the portion of indebtedness incurred in respect of such acquisition costs and capital expenditures by the Operating Subsidiary.

To the extent Operating Subsidiaries designate an expenditure as subject to the Deferred Purchase Price Payment:

(d) if the designated expenditure is funded by issuing additional Trust Units, by the proceeds of dispositions of the Canadian resource property component of Properties, by the disposition of Direct Royalties or by the issuance of debt, it will not be a charge against the net profits interest, and therefore will not reduce payments from the net profits interest to the Trust;

(e) the Trust will be obliged to pay to the Operating Subsidiaries 99% of the amount of the designated expenditure to the extent not funded by borrowing by the Operating Subsidiaries;

(f) the cost to the Trust of the designated expenditure will be added to the COGPE account of the Trust which will create additional tax deductions for the Trust; and

(g) the additional revenue generated from the Properties acquired by the designated expenditure will be added to the revenues used to calculate income from the net profits interest, thereby potentially increasing the amount payable to the Trust under the NPI Agreements.

To satisfy Deferred Purchase Price Payment obligations, the Trust may use proceeds from the issuance of additional Trust Units or proceeds from the disposal of a nets profits interest or other asset. The Trust is not required to pay an amount as a Deferred Purchase Price Payment except to the extent the Trust has such proceeds available.

Under the NPI Agreements, the Operating Subsidiaries are entitled to reserve such amounts of the revenues received from Production and other income received by the Operating Subsidiaries in respect of the Properties if, as and when Harvest Operations determines, in its reasonable discretion, that it is prudent to provide for payment of future production costs. Amounts allocated to the reserve account are required to be used by the Operating Subsidiaries to fund the payment of production costs. When such production costs are paid, the amounts are adjusted in the calculation of the net profits interest.

Reserve Account

Under the NPI Agreements, the Operating Subsidiaries are entitled to reserve such amounts of the revenues received from Production and other income received by the Operating Subsidiaries in respect of the Properties if, as and when Harvest Operations determines, in its reasonable discretion, that it is prudent to do so in accordance with prudent business practices, to provide for payment of future production costs. Amounts Allocated by the Operating Subsidiaries to the Reserve Account are required to be used by the Operating Subsidiaries to fund the payment of production costs. When such production costs are paid, the amounts will be adjusted in the calculation of the net profits interest.

GENERAL DEVELOPMENT OF THE BUSINESS

Harvest was formed in July 2002 and for the next few years, acquired 8,500 boe/d of production in 2002, 7,475 boe/d in 2003, 24,000 boe/d in 2004 and 5,200 boe/d in 2005 for aggregate consideration of $1,127.7 million. For the year ended December 31, 2005, Harvest's production averaged 36,500 boe/d with a year-end exit rate of approximately 38,800 boe/d comprised of 53% light to medium oil, 34% heavy oil and 13% natural gas.

During the later half of 2005, Harvest agreed to complete a Plan of Arrangement with Viking to create a stronger entity with a more balanced portfolio of assets as well as to provide its security holders with greater liquidity and participation in one the largest oil and natural gas trusts in Canada. The benefits of combining the operations of Harvest and Viking were anticipated to be:

- The combined resources of Harvest and Viking would be significant in terms of personnel, undeveloped land, and property enhancement projects positioning the combined trust to more efficiently and effectively develop and enhance the combined asset base.

- The combined trust would have a strong balance sheet and increased access to low-cost capital by virtue of its larger market capitalization which should allow it to capitalize on its existing presence in the U.S. debt and equity capital markets.

- Combining the operations of Harvest and Viking would result in a balanced production portfolio with the ability to participate in strong commodity price markets for both oil and natural gas.

- It was expected that the enhanced scale of the combined trust would allow it to more effectively compete for new assets and oilfield service resources, generating efficiencies of operation.

- Each organization has a similar culture and utilizes many of the same operating systems which was expected to result in a smooth integration of the two businesses.

Year ended December 31, 2006

On February 2, 2006, the Unitholders of Harvest and of Viking approved a resolution to merge the two trusts based on an exchange ratio of 0.25 Harvest Trust Units for every Viking trust unit with Harvest receiving all of the assets of Viking. In addition to the issuance of 46,040,788 Trust Units with an ascribed value of $1,638.1 million, Harvest also assumed $106.2 million of bank debt and the obligations of Viking's 10.5% and 6.40% unsecured subordinated convertible debentures with $35.1 million and $175.0 million of principal amount outstanding, respectively, bringing the total consideration for the acquisition to $1,975.3 million including acquisition costs of $4.6 million. Production from all of Viking's assets was approximately 24,000 BOE/d comprised of approximately 50% natural gas and 50% oil and natural gas liquids.

On July 26, 2006, Harvest entered into an agreement to purchase all of the issued and outstanding shares of Birchill for cash consideration of $446.8 million. At the date of acquisition, Birchill's production was approximately 6,300 BOE/d weighted 65% natural gas and 35% light/medium oil and natural gas liquids with approximately 57% produced from properties located in areas adjacent to our Markerville, Ferrier and Willesden Green properties. In addition, Birchill's Mulligan property in the Peace River Arch produced approximately 2,000 BOE/d of natural gas and natural gas liquids.

On August 22, 2006, Harvest entered into the Purchase and Sale Agreement to acquire all of the issued and outstanding shares of North Atlantic for cash consideration of $1,597.8 million and closed the transaction on October 19, 2006. The principal assets of North Atlantic are a sour crude hydrocracking refinery located in the Province of Newfoundland and Labrador and a marketing division with 64 gasoline stations, a home heating business and a commercial and wholesale petroleum products business, also located in the Province of Newfoundland and Labrador. The Refinery is capable of processing 115,000 barrels per day of crude oil feedstocks with a sulphur content as high as 3.5% and an API gravity in the range of 25° to 40° and has a docking facility capable of handling vessels in excess of 200,000 dead weight tons capable of carrying up to 2 million barrels of crude oil. The Refinery's product slate is weighted towards high quality gasoline, jet fuel and diesel fuel that are compliant with current product specifications including sulphur, cetane and aromatic content. The acquisition of North Atlantic created a second business segment for Harvest. Subsequent to purchasing North Atlantic, Harvest had two operating business units: its upstream operations in western Canada and its downstream operations in the Province of Newfoundland and Labrador.

On October 31, 2006, the Government of Canada proposed the implementation of tax on publicly traded mutual fund trusts at rates comparable to the combined federal and provincial corporate tax rates. This was accomplished by eliminating the deductibility of distributions to unitholders, taxing the trust’s income at corporate rates and treating the distributions to unitholders as taxable dividends from a corporation with an effective date of January 1, 2011. These provisions also provided that any “undue expansion” (defined as expansion beyond “normal growth”) could result in the tax being applied sooner than January 1, 2011. The “normal growth” guideline is measured by reference to the market capitalization of the entity as of the end of trading on October 31, 2006 which for Harvest totalled approximately $3.7 billion which entitled Harvest to issue an additional $4.3 billion of Trust Units and Debentures prior to January 1, 2011 reflecting its market capitalization plus debt held by the Trust on October 31, 2006. As of March 24, 2009, Harvest had approximately $2.4 billion of “normal growth” available.

During 2006, Harvest's upstream production averaged approximately 59,729 BOE/d with a year end exit rate of approximately 65,023 BOE/d comprised of approximately 45% light and medium oil, 25% heavy oil and 30% natural gas. Capital spending on internal development opportunities increased to $398.3 million, an increase of $277.8 million over the prior year. For the month of December 2006, the throughput of the North Atlantic refinery totalled 101,679 BOE/d, being the first month of full operations since acquiring the Refinery on October 19, 2006.

Year ended December 31, 2007

On June 11, 2007, Harvest and Grand entered into a pre-agreement whereby Harvest agreed to make an offer to purchase all of the issued and outstanding shares of Grand for $3.84 per share in cash subject to there being at least $66^{2/3}$% of the outstanding shares tendered to the offer. On July 26, 2006, Harvest acquired approximately 74.6% of the outstanding shares of Grand and extended our offer to August 9, 2007, when we acquired an additional 20% of the Grand shares and proceeded to acquire the remaining shares pursuant to the compulsory acquisition provisions of the ABCA. In aggregate, the acquisition cost for Grand totalled $139.3 million comprised of: $109.7 million to acquire the shares of Grand, $28.8 million to repay Grand’s bank debt and $0.8 million in respect of related acquisition costs. During the three months ended March 31, 2007, Grand’s production averaged 3,409 BOE/d comprised 68% light oil and 32% natural gas.

During 2007, Harvest's upstream production averaged approximately 60,336 BOE/d comprised of approximately 49% light and medium oil, 24% heavy oil and 27% natural gas. Capital spending on internal development in our upstream business aggregated to $300.7 million, a decrease of $76.2 million over the prior year while capital spending in our downstream business totalled $44.1 million. For 2007, the daily throughput of feedstock for the Refinery averaged 98,617 bbls/d reflecting two planned shutdowns in the fourth quarter for turnaround and scheduled maintenance activities.

Year ended December 31, 2008

On July 24, 2008, Harvest acquired all of the issued and outstanding shares of a private corporations with production of approximately 390 bbl/d of light oil and 2,300 mcf/d of natural gas for cash consideration $36.8 million. On September 8, 2008, Harvest acquired petroleum and natural gas producing properties in the Peace River Arch area of northern Alberta with approximately 1,250 bbl/d of light oil and 3,900 mcf/d of natural gas for cash consideration of $130.8 million plus some minor property interests which produced approximately 85 BOE/d.

During 2008, Harvest's upstream production averaged approximately 55,932 BOE/d comprised of approximately 50% light and medium oil, 22% heavy oil and 28% natural gas. Capital spending on internal development in our upstream business aggregated to $271.3 million, a reduction of $29.4 million as compared to the prior year while capital spending in our downstream business totalled $56.2 million as compared to $44.1 million in 2007. For 2008, the daily throughput of feedstock for the Refinery averaged 103,497 bbls/d as compared to 98,617 bbls/d in the prior year when two planned shutdowns in the fourth quarter for turnaround and scheduled maintenance activities limited production.

GENERAL BUSINESS DESCRIPTION

Overview

With its acquisition of North Atlantic in October 2006, Harvest became an integrated petroleum and natural gas producer with upstream operations located in Alberta, Saskatchewan and British Columbia, Harvest employs a disciplined approach to acquiring high working interest, large resource-in-place, producing properties and uses "best practice" technical and field operational processes to extract maximum value from its assets. These operational processes include hands-on approach to management with a focus on optimizing production rates, the application of enhanced oil recovery and other technologies and selective capital investment to maximize reservoir recovery while stressing operational efficiencies to control operating costs. As at March 24, 2009, Harvest employed 380 full-time employees in its upstream business, 241 of which are located in the head office and 129 of which are located in the field.

Harvest's downstream business consists of a sour oil hydrocracking refinery with related docking and storage facilities as well as a retail gasoline, home heating, commercial, wholesale and bunkers business all operated in Province of Newfoundland and Labrador. As at March 24, 2009, Harvest employed 519 full-time employees and 48 part-time employees in its downstream business, all of which are located in the Province of Newfoundland and Labrador.

Business Strategies, Policies & Practices

Harvest's business strategy is focused on cash flow generation, acquiring assets with identified operational and development opportunities and increasing the long-term value of its assets with proven development strategies. Prior to 2006, Harvest had applied its strategies to opportunities in the petroleum and natural gas industry in western Canada. With the valuation of petroleum and natural gas assets in western Canada ever increasing through 2005 and into 2006, the opportunities to acquire such assets with significant upside potential became difficult. As a result, in 2006 Harvest changed its focus in western Canada to aggressively pursuing development opportunities within our existing asset base and in 2007, implemented three enhanced oil recovery projects with modest capital requirements but the potential to add significant reserves.

In 2006, Harvest expanded its core business to include crude oil refining and a retail petroleum marketing business. This initiative was undertaken to diversify our business with a long-life asset that has considerable growth potential by increasing the throughput, shifting the yield to higher-valued refined products as well as enhancing capacity to handle a heavier, more-sour crude oil feedstock. Our expectations are that the impact of the medium/heavy crude oil differential prices experienced by our upstream operations in western Canada will be somewhat offset by the impact of these differentials on our crude oil feedstock cost in our downstream operations.

Upstream Segment

Within the upstream segment, Harvest employs the following operating strategies:

1. **Acquire Properties with Operational and Development Opportunities** - Harvest will continue to selectively acquire properties with an established production history and once acquired, focus on improving resource recovery, reducing costs and extending reserve life thereby creating additional value for its Unitholders. Harvest will continue to evaluate future acquisitions on the basis of their net present value.

2. **Enhanced Oil Recovery Projects** - Harvest will continue to promote its enhanced oil recovery projects. At Wainwright, we are introducing an alkaline surfactant polymer flood pilot to improve recovery rates. With success of this pilot, we will likely expand the project to impact a larger portion of the reservoir at Wainwright. At both Bellshill Lake and Suffield, we are increasing our injected water by introducing water produced at adjacent properties to re-pressurize the reservoir. We have also identified opportunities for similar projects at other fields which may be implemented beyond 2009.

3. **Increase Operating Netbacks** - Harvest focuses on reducing operating costs and optimizing marketing alternatives to increase its operating netback and thereby extending the life and increasing the value of its proved reserves. Cost reduction initiatives include continuous improvements to water handling and disposal alternatives and contracting for volume discounts on well servicing and purchased materials. Optimizing marketing alternatives includes blending crude oil production to meet pricing specifications and reviewing transportation alternatives to achieve the highest prices available at the wellhead.

4. **Insurance Coverage** - In addition to preventative maintenance operating practices, Harvest maintains property damage and business interruption insurance to mitigate the risk associated with its practice of controlling operations and future development by maintaining a high working interest in its petroleum and

natural gas properties. Harvest's property damage coverage is subject to a $500,000 deductible per occurrence and a claim limit of $150 million while the business interruption insurance covers its five highest revenue generating properties subject to a 30 day deductible period and claim limit of $150 million. Harvest also maintains an industry standard environmental, health and safety program – See "Environmental, Health & Safety Policies & Practices" below under “Other Upstream Information”.

Downstream Segment

Within the downstream segment, Harvest employs the following operating strategies:

1. **Acquire Established Operating Facilities –** The North Atlantic operations acquired by Harvest in 2006 had over ten years of continuous operations with a committed workforce and operating plan. In respect of the related feedstock procurement and marketing of refined products, Harvest has contracted with the vendor to provide these services as well as the related working capital financing subject to a mutual six month termination clause. The Refinery is currently configured to produce high quality gasoline and distillates from a medium gravity sour feedstock that meet or exceed the ever increasing environmental requirements.

2. **Profitability Improvement and Expansion –** We have identified a “de-bottlenecking project” involving an increase in the design capacity from 115,000 bbl/d to 120,000 bbl/d, improving the yield of gasoline and distillate products, enhancing the feedstock receiving and storage facilities and improving the process heating design and combustion technologies at an estimated cost of $300 million over the next three years.

3. **Insurance Coverage –** Subsequent to its acquisition by Harvest, North Atlantic maintains property damage and business interruption insurance on its refinery operations to a maximum annual loss limit of US$1 billion subject to a property damage deductible of $7.5 million and a 45 day deductible period for the business interruption coverage. North Atlantic receives its crude oil feedstock via water born vessels and protects its exposure to marine pollution and related clean-up by requiring any vessel delivering feedstock to the Refinery or shipping refined products from the Refinery to carry US$1 billion of coverage per vessel and to insure the cargo for 110% of its value.

Cash Flow Risk Management

Harvest’s cash flow risk management strategies are financially integrated reflecting the commodity price risk of our cash flow from producing crude oil in western Canada is financially offset by our requirement to purchase crude oil feedstock for our downstream operations even though the crude oil produced in western Canada does not physically flow to our refinery in Newfoundland. As a result, our 2009 cash flow at risk is comprised of approximately 33,000 bbls/d of refined product price exposure, 82,000 bbls/d of refined product crack spread exposure and 84,000 mcf/d of western Canadian natural gas price exposure.

Commencing in 2006, we have limited our financial counterparties to lenders in our syndicated Credit Facility as the security provided under our Credit Facility will extend to our price risk management contracts. This eliminates the requirement for margin calls and the pledging of collateral as well as enables the negotiation of a more limited number of events of default which contributes to limiting the potential that these contracts could exacerbate credit concerns.

UPSTREAM BUSINESS
STATEMENT OF RESERVES DATA

The statement of reserves data and other oil and natural gas information set forth below (the "**Statement**") is dated March 24, 2009. The effective date of the Statement is December 31, 2008 and the preparation date of the Statement is March 24, 2009.

Disclosure of Reserves Data

Harvest retained the qualified, Independent Reserves Engineering Evaluators to evaluate and prepare reports on 100% of Harvest's crude oil and natural gas reserves as of December 31, 2008. Harvest's reserves were evaluated by McDaniel (who evaluated approximately 35% of Harvest's total proved plus probable reserves), and GLJ (who evaluated approximately 65% of Harvest's total proved plus probable reserves). All of Harvest's reserves were evaluated using the price and cost assumptions of McDaniel as at January 1, 2009.

The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Operating Subsidiaries and the net present values of future net revenue for these reserves using forecast prices and costs. The Reserve Report has been prepared by the Independent Reserve Engineering Evaluators in accordance with the standards contained in the COGE Handbook and the reserve definitions and other requirements contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Operating Subsidiaries engaged the Independent Reserve Engineering Evaluators to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Operating Subsidiaries' reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan.

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.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Operating Subsidiaries' 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.

Reserves Data (Forecast Prices and Costs) – December 31, 2008

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2008
FORECAST PRICES AND COSTS

	RESERVES					
	LIGHT AND MEDIUM OIL(1)		HEAVY OIL(1)		NATURAL GAS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)
PROVED						
Developed Producing	57,097	51,230	33,009	28,460	192,263	163,165
Developed Non-Producing	1,031	793	3,120	2,506	13,826	11,733
Undeveloped	10,377	8,768	4,116	3,281	25,884	20,551
TOTAL PROVED	68,505	60,792	40,245	34,246	231,973	195,449
PROBABLE	28,788	25,139	18,977	15,353	90,175	72,962
TOTAL PROVED PLUS PROBABLE	97,293	85,932	59,224	49,601	322,148	268,411

	RESERVES			
	NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (MBOE)	Net (MBOE)
PROVED				
Developed Producing	6,060	4,380	128,209	111,265
Developed Non-Producing	336.4	226.2	6,791	5,481
Undeveloped	450.4	316.9	19,258	15,792
TOTAL PROVED	6,847	4,924	154,260	132,538
PROBABLE	2,865	2,001	65,660	54,654
TOTAL PROVED PLUS PROBABLE	9,712	6,924	219,919	187,191

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) (2) 0% ($M)	5% ($M)	10% ($M)	15% ($M)	20% ($M)	Value Per Boe Before Income Tax Discounted At 10%/year ($/BOE)
PROVED						
Developed Producing	4,338,216	3,228,308	2,585,638	2,167,463	1,873,893	20.17
Developed Non-Producing	203,785	149,313	118,276	97,911	83,361	17.42
Undeveloped	510,049	340,498	238,437	172,178	126,637	12.38
TOTAL PROVED	5,052,051	3,718,119	2,942,351	2,437,552	2,083,890	19.07
PROBABLE	2,655,044	1,466,172	951,936	680,106	516,350	14.50
TOTAL PROVED PLUS PROBABLE	7,707,095	5,184,291	3,894,288	3,117,659	2,600,239	17.71

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year) (2) 0% ($M)	5% ($M)	10% ($M)	15% ($M)	20% ($M)
PROVED					
Developed Producing	4,018,049	3,037,535	2,461,527	2,081,628	1,811,745
Developed Non-Producing	187,252	139,006	110,967	92,340	78,927
Undeveloped	476,847	315,366	218,755	156,330	113,588
TOTAL PROVED	4,682,148	3,491,907	2,791,249	2,330,299	2,004,259
PROBABLE	2,418,525	1,331,017	861,713	614,458	465,909
TOTAL PROVED PLUS PROBABLE	7,100,673	4,822,925	3,652,961	2,944,758	2,470,168

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($M)	ROYALTIES ($M)	OPERATING COSTS ($M)	DEVELOP-MENT COSTS ($M)	WELL ABANDON-MENT COSTS ($M)	FUTURE NET REVENUE BEFORE INCOME TAXES[(2)] ($M)	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES[(2)]
Proved Reserves	11,496,207	1,619,730	4,140,526	489,469	194,427	5,052,051	369,903	4,682,148
Proved Plus Probable Reserves	17,293,428	2,542,791	6,129,949	695,256	218,333	7,707,095	606,422	7,100,673

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($M) [(2)]	UNIT VALUE ($/bbl or $/mcf)
Proved Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	1,102,723	23.35
	Heavy Crude Oil (including solution gas and associated by-products)	1,142,183	22.19
	Associated and Non-Associated Natural Gas (including associated by-products)	695,257	3.95
		2,940,163	
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	1,460,937	21.44
	Heavy Crude Oil (including solution gas and associated by-products)	1,517,611	21.07
	Associated and Non-Associated Natural Gas (including associated by-products)	912,517	3.77
		3,891,065	

Notes to Reserves Data Tables

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. We have presented Hay River reserves as medium gravity crude in the reserve 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 light/medium oil reserves by the following amounts: Proved Developed Producing: 11.2 MMbbl, Proved Undeveloped: 6.9 MMbbl, Total Proved: 18.1 MMbbl, Probable: 5.3 MMbbl and Proved plus Probable: 23.3 MMbbl, and would increase the net heavy oil reserves and reduce the light/medium oil reserves by the following amounts: Proved Developed Producing: 9.8 MMbbl, Proved Undeveloped: 5.8 MMbbl, Total Proved: 15.6 MMbbl, Probable: 4.7 MMbbl, and Proved plus Probable: 20.2 MMbbl.

2. The Trust is entitled to deduct from its income all amounts which are paid or payable by it to Unitholders in a given financial year. As a result of amounts paid to Unitholders in the course of the most recent financial year, the Trust is not liable for any material amount of income tax on income. The Government of Canada has enacted legislation to tax distributions by the Trust commencing January 1, 2011. See "Risk Factors - Risks Related to Harvest's Structure - Changes to the Tax Act.

3. Columns may not add due to rounding.

4. The crude oil, natural gas liquids and natural gas reserve estimates presented in the Reserve Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

5. The crude oil, natural gas liquids and natural gas reserve estimates presented in the Reserve Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of these definitions are set forth below:

   Reserve Categories

   Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

   - analysis of drilling, geological, geophysical and engineering data;

   - the use of established technology; and

   - specified economic conditions.

   Reserves are classified according to the degree of certainty associated with the estimates.

   (a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

   (b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

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

(c) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(d) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(e) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(f) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

Forecast prices and costs are those:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Operating Subsidiaries is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the Reserve Report, based on McDaniel's then current forecasts at the date of the Report, were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of January 1, 2009
FORECAST PRICES AND COSTS

	OIL					NATURAL GAS	NATURAL GAS LIQUIDS	INFLATION RATES (6)	U.S./ CAN EXCHANGE RATE(7)
Year Forecast	WTI Crude Oil(1) ($US/ bbl)	Edmonton Light Crude Oil(2) ($Cdn/ bbl)	Alberta Heavy Crude Oil(3) ($Cdn/ bbl)	Alberta Bow River Hardisty Crude Oil(4) ($Cdn/ bbl)	Sask Cromer Medium Crude Oil(5) ($Cdn/ bbl)	Alberta AECO Spot Price ($Cdn/ GJ)	Edmonton Cond. and Natural Gasolines ($Cdn/ bbl)	(%/Year)	($US/$Cdn)
2009	60.00	69.60	47.00	54.80	61.80	7.40	71.60	2.0	0.85
2010	71.40	83.00	56.10	65.30	73.70	8.00	85.00	2.0	0.85
2011	83.20	91.40	61.80	72.00	81.20	8.45	93.50	2.0	0.90
2012	90.20	93.90	64.00	73.90	83.40	8.80	96.00	2.0	0.95
2013	97.40	96.30	65.60	75.90	85.60	9.05	98.50	2.0	1.00
2014	99.40	98.30	67.00	77.40	87.40	9.25	100.50	2.0	1.00
2015	101.40	100.30	68.80	79.00	89.10	9.45	102.60	2.0	1.00
2016	103.40	102.30	70.20	80.50	90.90	9.60	104.60	2.0	1.00
2017	105.40	104.20	71.60	82.10	92.60	9.80	106.50	2.0	1.00
2018	107.60	106.40	73.00	83.80	94.60	10.00	108.80	2.0	1.00
2019	109.70	108.50	74.50	85.40	96.40	10.20	110.90	2.0	1.00
2020	111.90	110.70	76.00	87.20	98.30	10.40	113.20	2.0	1.00
2021	114.10	112.80	77.50	88.90	100.30	10.60	115.30	2.0	1.00
2022	116.40	115.10	79.00	90.70	102.30	10.80	117.70	2.0	1.00
2023	118.80	117.50	80.70	92.50	104.40	11.05	120.10	2.0	1.00
There-after	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	1.00

Notes:

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API/0.5% sulphur.
(2) Edmonton Light Sweet 40 degrees API, 0.3% sulphur.
(3) Heavy crude oil 12 degrees API at Hardisty Alberta (after deduction of blending costs to reach pipeline quality).
(4) Bow River at Hardisty Alberta (Heavy stream).
(5) Midale Cromer crude oil 29 degrees API, 2.0% sulphur.
(6) Inflation rates for forecasting prices and costs.
(7) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by the Operating Subsidiaries for the year ended December 31, 2008, were $8.60/Mcf for natural gas, $75.16/bbl for natural gas liquids, $89.72/bbl for light/medium oil, and $77.22/bbl for heavy oil.

6. Future Development Costs

The following table sets forth development costs deducted in the estimation of the Operating Subsidiaries' future net revenue attributable to the reserve categories noted below.

	Forecast Prices and Costs ($M)	
Year	Proved Reserves	Proved Plus Probable Reserves
2009	$165,210	$227,956
2010	$85,484	$148,572
2011	$64,575	$78,820
2012	$14,414	$35,544
2013	$4,416	$12,072
Thereafter	$155,370	$192,291
Total Undiscounted	$489,469	$695,256
Total Discounted at 10%	$350,814	$506,064

Future development costs will be funded through cash flow and the Trust's Credit Facility.

7. Estimated future abandonment costs related to a property have been taken into account by the Independent Reserve Engineering Evaluators in determining reserves that should be attributed to a property and in determining the aggregate future net revenue there from. No allowance was made, however, for reclamation of well sites or the abandonment and reclamation of any facilities. See “Other Upstream Business Information – Additional Information Concerning Abandonment and Reclamation Costs” for more information.

8. The forecast price and cost assumptions assume the continuance of current laws and regulations.

9. The extent and character of all factual data supplied to the Independent Reserve Engineering Evaluators were accepted by the Independent Reserve Engineering Evaluators as represented. No field inspection was conducted.

Reconciliations of Changes in Reserves

RECONCILIATION OF
OPERATING SUBSIDIARIES COMPANY GROSS
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED NATURAL GAS		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
31-Dec-07	65,532	27,029	92,561	40,620	20,073	60,692	245,012	96,638	341,650
Extensions/ Improved Recovery	4,898	2,205	7,103	1,066	716	1,783	16,556	4,120	20,676
Technical Revisions	2,158	(1,673)	485	4,452	(1,803)	2,652	1,737	(12,585)	(10,848)
Discoveries	24	(22)	2	3	4	7	808	28	836
Acquisitions	3,685	1,261	4,946	0	0	0	12,650	3,670	16,319
Dispositions	(33)	(12)	(45)	(66)	(13)	(79)	(9,739)	(1,696)	(11,435)
Production	(7,758)	0	(7,758)	(5,831)	0	(5,831)	(35,050)	0	(35,050)
31-Dec-08	68,505	28,788	97,293	40,245	18,977	59,224	231,973	90,175	322,148

	NATURAL GAS LIQUIDS			TOTAL (BOE)		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)
31-Dec-07	7,469	3,250	10,718	154,456	66,458	220,914
Extensions/ Improved Recovery	454	152	605	9,177	3,760	12,937
Technical Revisions	(186)	(566)	(751)	6,713	(6,142)	574
Discoveries	0	(0)	0	163	(14)	149
Acquisitions	143	40	183	5,937	1,912	7,849
Dispositions	(53)	(10)	(63)	(1,776)	(314)	(2,094)
Production	(980)	0	(980)	(20,411)	0	(20,411)
31-Dec-08	6,847	2,865	9,712	154,260	65,660	219,919

Note:
(1) Columns may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook.

As at January 1, 2009, Harvest has a total of 26.1 MMBOE of gross reserves that are classified as proved non-producing. Of these non-producing reserves approximately 74% 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 January 1, 2009. Substantially all of the undeveloped reserves are based on Harvest's then current 2009 budget and long range development plans for the major assets noted elsewhere in this document. Approximately 80% of these reserves are expected to be developed within the next two years. The remaining undeveloped reserves are expected be developed over the next five years, in most cases due to processing facility capacity restrictions. The capital cost has been taken into account for these programs in the estimated future net revenue.

TIMING OF INITIAL UNDEVELOPED
RESERVES ASSIGNMENT

		Gross Reserves First Attributed by Year				
PRODUCT TYPE	Units	Prior	2006	2007	2008	Total
Proved Undeveloped						
Light and Medium Crude Oil	Mbbl	696	925	1,826	65	3,512
Heavy Crude Oil	Mbbl	600	1,428	5,290	3,663	10,981
Natural Gas	MMcf	65	6,164	22,494	(2,840)	25,884
Natural Gas Liquids	Mbbl	23	219	202	6	450
Total Oil Equivalent	MBOE	1,330	3,599	11,067	3,261	19,257
Probable Undeveloped						
Light and Medium Crude Oil	Mbbl	1,049	844	7,837	(48)	9,682
Heavy Crude Oil	Mbbl	3,048	1,185	5,802	(1,179)	8,856
Natural Gas	MMcf	740	4,328	21,972	(3,260)	23,781
Natural Gas Liquids	Mbbl	60	155	775	93	1,083
Total Oil Equivalent	MBOE	4,280	2,906	18,076	(1,677)	23,585

Notes:

(1) Hay River reserves are considered to be heavy crude oil for this analysis.

(2) First attributed volumes include additions during the year and do not include revisions to previous undeveloped reserves.

Significant Factors or Uncertainties

Information in this Annual Information Form contains forward-looking information and estimates with respect to Harvest. This information addresses future events and conditions, and as such involves risks and uncertainties that could cause actual results to differ materially from those contemplated by the information provided. These risks and uncertainties include but are not limited to factors intrinsic in domestic and international politics and economics, general industry conditions including the impact of environmental laws and regulations, imprecision of reserves estimates, fluctuations in commodity prices, interest rates or foreign exchange rates and stock market volatility. The information and opinions concerning the Trust's future outlook are based on information available at March 27, 2009.

Important economic factors that should be taken into consideration that may affect particular components of the reserve data include: oil pricing, power costs and operating expenses.

Oil and Gas Wells

The following table sets forth the number of wells in which Harvest held a working interest as at December 31, 2008:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	3,229	2,627	1,125	933	1,886	843	653	421
British Columbia	130	130	49	49	2	2	17	9
Saskatchewan	1,134	938	454	411	35	34	11	11
Total	4,493	3,695	1,628	1,393	1,923	879	681	441

	Service Wells			
	Active		Suspended	
	Gross	Net	Gross	Net
Alberta	634	536	50	40
British Columbia	108	108	2	2
Saskatchewan	142	129	74	57
Total	884	773	126	99

Note:

(1) "Gross Wells" are wells in which Harvest has an interest (operating or non-operating).
(2) "Net Wells" are Harvest's interest share of the gross wells (operating or non-operating).

Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which Harvest completed during its 2008 financial year:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil Wells	-	-	119	101.8
Gas Wells	2	2.0	120	41.0
Service Wells	2	2.0	4	3.5
Dry Holes	-	-	-	-
Total Wells	4	4.0	243	146.3

Note:

(1) "Gross Wells" are wells in which Harvest has an interest (operating or non-operating).
(2) "Net Wells" are Harvest's interest share of the gross wells (operating or non-operating).

For a discussion of Harvest's exploration and development activities refer to the "2009 Capital Expenditures Plan" section under “Other Upstream Information”.

Properties with No Attributed Reserves

The following table sets out Harvest's undeveloped land holdings as at December 31, 2008.

	Undeveloped Acres	
	Gross	Net
Alberta	568,335	391,291
British Columbia	44,525	34,411
Saskatchewan	89,221	77,489
Total	702,081	503,191

	Undeveloped Acres for which rights expire within one year	
	Gross	Net
Alberta	109,462	78,927
British Columbia	5,258	2,712
Saskatchewan	17,773	16,188
Total	132,493	97,827

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 will be less than indicated above.

Production Estimates

The following table sets forth the volume of production from the company's gross reserves estimated for 2009 as found in the Reserve Report:

	2009 Production Forecast				
	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Total (BOE/d)
Proved Producing	19,614	14,432	89,995	2,587	51,631
Proved Developed Non-Producing	317	797	5,418	103	2,120
Proved Undeveloped	2,316	657	4,793	93	3,864
Total Proved	22,248	15,884	100,206	2,783	57,616
Total Probable	1,399	1,189	8,322	263	4,238
Total Proved Plus Probable	23,646	17,073	108,528	3,046	61,855

OTHER UPSTREAM BUSINESS INFORMATION

Oil and Natural Gas Properties

The Operating Subsidiaries' portfolio of significant Properties is discussed below. Reserve amounts discussed are gross reserves and are stated at December 31, 2008 based on forecast prices and cost assumptions. Although the Trust receives income from each of the Operating Subsidiaries pursuant to the NPI, interest and principal payments and trust and partnership distributions, all oil and natural gas operations and the management of the Trust are conducted by Harvest Operations.

In general, the 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 reserve addition through extending the economic life of these producing properties beyond the limits used in the Reserve Report and developing new proven reserves previously not evaluated by the Independent Reserve Engineering 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.

2008 Historical Production by Material Property

Material Property	Light, Medium and Heavy Crude Oil (bbls/d)	Natural gas (Mcf/d)	NGL (bbls/d)	Average Daily Production (BOE/d)
Markerville	856	23,609	812	5,603
Southeast Saskatchewan	5,040	302	60	5,150
Hay River	4,542	432	-	4,614
Suffield	3,803	539	37	3,930
Rimbey	200	12,858	678	3,021
Red Earth	2,689	360	62	2,811
Hayter	2,556	406	9	2,632
Wainwright	2,609	104	1	2,628
Bellshill Lake	2,326	920	49	2,529
Crossfield	15	6,910	344	1,511
Lloydminster	1,209	387	-	1,274
Other	11,410	49,488	572	20,229
Total	37,255	96,315	2,624	55,932

Principal Producing Properties at December 31, 2008

Markerville: The Markerville area is located approximately 35 kilometres southwest of Red Deer, Alberta. Harvest is the operator for a majority of the production in the area and has a working interest varying from 50-90% in the majority of the area's wells. Markerville averaged 5,603 BOE/d (70% natural gas) for the 12 months ending December 31, 2008. The area offers multi-zone potential with a number of producing horizons. The Pekisko formation, at a well depth of approximately 2,200 metres, contains sweet natural gas along with associated liquids. The formation is developed using both vertical and horizontal wells. The Edmonton sands are a tight gas reservoir located at a depth of approximately 800 metres that contains sweet natural gas that is developed exclusively with vertical wells. Harvest also has a 25-50% working interest in Leduc Pinnacle Reef formations that produce light oil and associated natural gas. In 2008, the company drilled or participated in 63 gross (26.9 net) wells including 52 gross (20.4 net) wells into the Edmonton sands formation. Harvest has various ownership in pipelines, compressors, and gas processing facilities that service the wells in this area.

Southeast Saskatchewan: Our southeast Saskatchewan properties are located approximately 110 miles southeast of Regina. Production from southeast Saskatchewan averaged 5,040 bbl/d of average 33° API crude oil in 2008, primarily produced from the Tilston and Souris Valley Formations of Mississippian age. Harvest has an average working interest of over 90% in this primarily operated property. In 2008 Harvest drilled 43 gross (35.5 net) wells, primarily horizontal development and infill wells into defined pools including a test well into the Bakken formation to evaluate the extent of this hydrocarbon accumulation on Harvest lands. Fluid produced from the area is processed at our 100% owned Hazelwood facility and is pipeline connected to the Enbridge system. Additional future development at southeast Saskatchewan may include step-out and horizontal infill drilling of up to 100 locations to increase the recovery factor and accelerate production. Harvest believes further drilling opportunities are possible through the continued pooling of other landowner interests to drill under-exploited areas. Harvest has extensive proprietary 3D seismic coverage which offers control of the opportunity, and will be used to identify further opportunities on and off our land base.

Hay River: Hay River was acquired by Harvest on August 2, 2005 and is located approximately 125 miles NW of Grande Prairie in northeastern British Columbia. In 2008 Hay River produced 5,542 bbl/d of medium gravity (24° API) crude oil which was processed at our central emulsion processing facility with the clean oil transported via pipeline to sales points. Hay River is a winter only access area in that drilling operations can only be undertaken when the ground is frozen (typically between late December 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 an average 100% working interest in this operated property. In 2008, Harvest focused on increasing water injection into the producing Blue Sky 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.

Suffield*:* Suffield is located 160 miles SE of Calgary and is located on the site of the Canadian Forces Base Suffield. Production from this region averaged 3,803 BOE/d of primarily heavy oil in 2008, averaging 11-18° API from the Upper Mannville Glauconitic formation. Harvest has an average 99% working interest in this operated property. Fluid produced from the area is processed at three emulsion processing facilities located at Caen, Lark and Batus with clean oil transported via pipeline to sales points. In 2008 Harvest drilled 12 gross (12 net) wells to optimize our producing infrastructure in the region. In addition, a pipeline was installed from our main processing facility at Batus to our Lark pool to transfer produced water for re-injection. By increasing injection into the Lark pool, Harvest believes the ultimate recovery of oil will be increased. Future development at Suffield may include step-out, extension and infill drilling at up to 50 identified locations. Pool optimization and enhanced recovery projects will target increased water injection into under-injected reservoirs that have not received adequate pressure maintenance similar to our Lark Pool.

Rimbey*:* The Rimbey area is located approximately 50 miles NW of Red Deer. In 2008 the Rimbey area produced 3,021 BOE/d of primarily natural gas (approximately 70%) from various formations including the Rock Creek, Viking, Ostracod, and Cardium. Harvest's working interest in this area ranges from 25% to 100%. In 2008 Harvest drilled 21 gross (7.3 net) wells. Harvest continued to build on a successful exploration program in 2007 at Chedderville by drilling an additional 3 delineation wells into the Basal Mannville (Ostracod) formation. Gas produced from this area is generally transported on company owned and third party owned infrastructure to five company owned compression facilities at Wilson Creek and Rose Creek, Willesden Green and Ferrier as well as third party gas processing facilities.

Red Earth*:* Production in 2008 from Red Earth averaged 2,689 BOE/d of oil (98% oil) averaging 37° to 39° API from the Devonian Slave Point, Granite Wash and Gilwood Formations. Harvest has an average 80% working interest in this primarily operated area. In 2008, Harvest drilled 12 gross (11.3 net) wells including a horizontal test well into the Slave Point formation. The horizontal well was completed using multi-stage fracturing technology successfully applied to other tight hydrocarbon formations. The Slave Point has typically been exploited using vertical wells, and the application of this technology has the potential to allow Harvest to access hydrocarbon previously not considered economic. Future development at Red Earth may include downspace drilling in the Slave Point G pool, 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 which was instrumental in the discovery of a new oil pool in the area, and will assist our plans to infill drill our identified Granite Wash and Slave Point pools.

Hayter*:* Harvest acquired the Hayter property in November 2002. Production in 2008 at Hayter averaged approximately 2,556 bbl/d of 14° to 15° API oil, producing from the Lower Cretaceous Cummings/Dina formation. Harvest has an average 94% working interest in this operated property. Emulsion produced from the wells is processed at one of two central processing facilities and then transported via pipeline to sales points. In 2008, Harvest drilled 11 gross (8.8 net) primarily horizontal wells to continue to infill under-exploited areas of this large oil pool. Future development at Hayter may include additional infill and step-out drilling with over 15 identified locations, as well as enhanced oil recovery projects. Harvest has identified the Hayter area as being amenable for enhanced recovery and will undergo additional testing of EOR techniques. Operating expense reduction projects such as low pressure water disposal wells, horizontal disposal wells, and battery optimization are ongoing.

Wainwright*:* Harvest acquired the Wainwright properties in September 2004. Production in 2008 from these pools averaged approximately 2,609 BOE/d of 22° to 24° API oil, produced from the Cretaceous Upper Mannville Sparky Formation. Harvest has an average 99% working interest in these operated properties. In 2008, Harvest finalized plans to construct a polymer injection facility and took delivery in the Fourth Quarter. This was a follow-up to a 2007 engineering study to evaluate the feasibility of using a polymer based injection fluid to increase waterflood sweep efficiencies and ultimate recoveries in this large oil pool. Injection is scheduled to commence in 2009.

Bellshill Lake: Harvest holds an average 98% working interest in this area, including a 100% working interest in the Bellshill Lake Ellerslie Unit, as well as working interests ranging from 6.5% to 100% in non-unit leases located next to the unit, all of which is operated by Harvest. Production consists of 26° to 28° API oil produced from the Ellerslie, and Dina formations, and totalled 2,529 BOE/d in 2008 weighted 90% towards oil and liquids. The Unit and area comprises 707 gross wells of which 580 are producing oil wells. There are 32 injection and service wells, and 95 suspended oil wells. The majority of these wells are tied-in to one central facility consisting of an oil processing facility, a water injection plant and a gas processing facility. Oil is transported to market via Gibson's pipeline and the gas is sold on the spot market. In 2008 Harvest constructed a water transfer line to bring incremental injection water to improve the ultimate recovery of oil from this large oil pool.

Crossfield: Crossfield is located approximately 20 miles NW of Calgary. Production in 2008 from this region was primarily natural gas (75%) with some liquids and averaged approximately 1,511 BOE/d from the Lower Cretaceous Basal Quartz formation. Harvest has an average 75% working interest in this operated and non-operated property. Harvest continues to evaluate opportunities to downspace and drill additional locations at Crossfield including the application of multi-stage fractured horizontal wells which have been successfully applied in similar geological formations.

Lloydminster: Harvest has a 100% working interest in this heavy oil field located 10 miles south of the town of Lloydminster. Production of 12-14 API heavy crude oil is from the Lloydminster sandstone formation, and averaged 1,274 BOE/d (98% oil) in 2008. Harvest drilled 18 gross (18 net) horizontal wells in 2008 pursuing infill drilling, downspacing and step-out opportunities. Production from the area wells is processed in single well batteries and then trucked to Harvest's Bellshill Lake pipeline terminal sales point. Future plans include downspacing the pool with additional horizontal wells and assessing the potential impact of water injection for pressure maintenance and enhanced recovery.

Capital Expenditures

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to Harvest's activities for the year ended December 31, 2008:

Property acquisition costs	($millions)
Proved properties	128.8
Undeveloped properties	7.8
Total property acquisition costs	136.6
Exploration costs	9.2
Development costs	254.2
Total Capital Expenditures	400.0

2009 Capital Expenditure Plan

Harvest's expected total capital spending on its oil and natural gas properties for 2009 is expected to be approximately $170 million. The primary areas of focus for Harvest's capital program during 2009 are the following:

- Hay River – Expenditures of approximately $75 million to drill 21 producing multi-leg horizontal oil wells; water injection wells and facilities; water source wells and upgrade processing infrastructure.

- Markerville – Drill 4 gross gas wells and construct associated infrastructure for an estimated cost of $7 million.

- Red Earth – Drill 3 gross light oil wells for a net expenditure of $5 million.

- Various Areas – Expenditures of approximately $28 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 Reserve Report. Opportunities being considered include:

- Implementation or optimization of enhanced waterfloods in selected pools such as Hay River 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;

- Optimizing field oil cut management through the shut-in of select wells and increased total fluid from offset higher oil cut wells. Shut-in wells would be available for restart as oil cuts vary;

- 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 3D seismic;

- Numerous exploratory opportunities defined by seismic from which value might be extracted by sale, farmout or joint venture;

- Opportunity to increase recovery factors in established pools using available and evolving enhanced recovery technologies such as Alkaline Surfactant Polymer at Wainwright, carbon dioxide injection at Bashaw and acid gas injection at Hayter.

Marketing Arrangements

Crude Oil and Natural Gas Liquids (NGLs)

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

Harvest received an average sales price, excluding the effects of commodity price risk management contracts, of $89.72/bbl for its light and medium crude oil, $77.22/bbl for its heavy crude oil and $75.16/bbl for its NGL's for the year ending December 31, 2008 compared to $64.09/bbl, $46.71/bbl and $62.26/bbl for the year ending December 31, 2007, respectively.

Natural Gas

Approximately 93% of Harvest's natural gas production is currently being sold at the prevailing daily spot market price in Alberta with the remaining 7% of its production dedicated to aggregator contracts which are contracted for the economic life of the reserves.

Harvest received an average sales price, excluding the effects of commodity price risk contracts, of $8.60/mcf for its natural gas for the year ending December 31, 2008 compared to $6.94/mcf in 2007.

Additional Information Concerning Abandonment and Reclamation Costs

The following table sets forth information respecting future abandonment and reclamation costs for surface leases, wells, facilities and pipelines which are expected to be incurred by Harvest and for the periods indicated:

Period	Abandonment & Reclamation costs (undiscounted and using a 2% inflation rate) ($000)	Abandonment & Reclamation costs (discounted at 10% using a 2% inflation rate) ($000)
Total as at December 31, 2008	1,277,767	241,044
Anticipated to be paid in 2009	14,303	13,003
Anticipated to be paid in 2010	9,269	7,661
Anticipated to be paid in 2011	21,797	16,377

The number of net wells for which the Independent Reserve Engineering Evaluators estimated that Harvest would incur abandonment and reclamation costs is 5,209 wells (Proved plus Probable).

Abandonment costs (excluding salvage values) associated only with wells to which reserves were attributed were deducted by the Independent Reserve Engineering Evaluators in estimating future net revenue in the Reserve Report. The estimated future undiscounted expense related to facilities, pipelines and no reserve addition wells is $1,100.8 million ($187.1 million discounted at 10%). The nature of these expenses are not expected to change the anticipated costs for the next three years as they will not be incurred until the end of a field's reserve life profile.

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

Average Daily Production Volumes (before the deduction of royalties)	2008				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil (bbls/d) [1]	25,509	25,365	25,210	24,295	25,093
Heavy Oil (bbls/d)	12,980	12,092	11,485	12,099	12,162
Total Oil (bbls/d)	38,489	37,457	36,695	36,395	37,255
NGL (bbls/d)	2,484	2,614	2,627	2,770	2,624
Natural Gas(Mcf/d)	102,570	93,014	93,628	96,079	96,315
Total Daily Production (BOE/d)	58,067	55,574	54,926	55,178	55,932

Total Sales Production	2008				
	Q1	Q2	Q3	Q4	Total
Light and Medium Oil (bbls) [1]	2,321,319	2,308,215	2,319,320	2,235,184	9,184,038
Heavy Oil (bbls)	1,181,180	1,100,372	1,056,620	1,113,120	4,451,292
Total Oil (bbls)	3,502,499	3,408,587	3,375,940	3,348,304	13,635,330
NGL (bbls)	226,029	237,859	241,670	254,826	960,384
Natural Gas (Mcf)	9,333,896	8,464,300	8,613,801	8,839,293	35,251,290
Total Production (BOE)	5,284,177	5,057,163	5,053,244	5,076,346	20,470,929

Average Sales Prices Received	2008				
	Q1	Q2	Q3	Q4	Total
Light & Medium oil ($/bbl) (1)	86.54	109.26	110.70	52.37	89.72
Heavy Oil ($/bbl)	69.04	96.79	99.21	42.44	77.22
Total Oil ($/bbl)	80.64	105.24	107.10	49.29	85.64
Natural Gas ($/Mcf)	8.28	10.86	8.44	6.95	8.60
NGL ($/bbl)	78.04	88.87	88.17	47.47	75.16
Total BOE ($/BOE)	71.41	93.29	90.15	46.99	75.39

Royalties Paid	2008				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil ($000) (1)	33,392	40,637	39,987	19,206	133,222
Heavy Oil ($000)	12,756	17,610	16,564	3,821	50,751
Natural gas & NGL's ($000)	16,252	18,567	16,717	12,936	64,472
Total BOE ($000)	62,400	76,814	73,268	35,963	248,445
Light & Medium Oil ($/bbl) (1)	14.38	17.61	17.24	8.59	14.51
Heavy Oil ($/bbl)	10.80	16.00	15.68	3.43	11.40
Natural gas & NGL's ($/BOE)	9.12	11.26	9.97	7.49	9.43
Total BOE ($/BOE)	11.81	15.19	14.50	7.08	12.14

Operating Expenses(2)	2008				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil ($000) (1)	37,372	36,673	36,749	43,504	154,298
Heavy Oil ($000)	14,920	16,445	16,819	20,258	68,442
Natural gas & NGL's ($000)	20,031	19,974	19,746	18,399	78,150
Total BOE ($000)	72,323	73,092	73,314	82,161	300,890
Light & Medium Oil ($/bbl) (1)	16.10	15.89	15.84	19.46	16.80
Heavy Oil ($/bbl)	12.63	14.94	15.92	18.20	15.38
Natural gas & NGL's ($/BOE)	11.24	12.12	11.77	10.65	11.43
Total BOE ($/BOE)	13.69	14.45	14.51	16.19	14.70

Netback Received(2)	2008				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil ($/bbl) (1)	56.06	75.76	77.62	24.32	58.41
Heavy Oil ($/bbl)	45.61	65.85	67.61	20.81	50.44
Natural gas & NGL's ($/BOE)	32.92	45.20	34.31	24.41	34.05
Total BOE ($/BOE)	45.91	63.65	61.14	23.72	48.55

Notes:

(1) Medium oil production includes production from our Hay River property. The crude oil from this property has an average API of 24^{o} (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.

Potential Acquisitions

Harvest continues to evaluate potential acquisitions of all types of petroleum and natural gas and other energy-related assets as part of its ongoing acquisition program. Harvest is normally in the process of evaluating several potential acquisitions at any one time which individually or together could be material. As of the date hereof, Harvest has not reached agreement on the price or terms of any potential material acquisitions and cannot predict whether any current or future opportunities will result in one or more acquisitions for Harvest.

Tax Horizon

In our structure, taxable income from the Operating Subsidiaries is transferred to the Trust on an annual basis and taxable income of the Trust is transferred to our Unitholders with the payment of distributions. The transfer of taxable income from the Operating Subsidiaries is primarily accomplished with the payment of the various net profits interests and the interest on the unsecured debt obligations owing to the Trust which are both deductible by the Operating Subsidiaries for income tax purposes. No material income taxes were paid by either the Trust or its subsidiaries in 2008. See "Risk Factors – Risks Related to Harvest's Structure - Re-assessment of Prior Years' Income Tax Returns."

Based on the current forward pricing for petroleum and natural gas as well as refined products, Harvest anticipates that there will be no income tax liability payable by either the Operating Subsidiaries or the Trust prior to 2013 even if Harvest were to convert to a corporation. If Harvest maintains its existing structure after 2010, its distributions will be taxed at rates of 25% in subsequent years. Harvest's future capital spending will further delay the tax horizon while a strengthening of commodity prices beyond that anticipated by the forward curve would result in tax pools being utilized earlier and the tax horizon accelerated. However, providing guidance on the timing of future cash income taxes is difficult in an industry with highly volatile commodity prices and significant fluctuations in the level of capital spending and distributions to Unitholders, all of which impact the tax horizon. See "Risk Factors – Risks Related to Harvest's Structure – Changes to the Tax Act."

Environment, Health and Safety Policies and Practices

Harvest has established internal environmental, health and safety guidelines and systems to ensure the health and safety of its employees, contractors and neighbouring residents and to ensure compliance with environmental laws, rules and regulations. These systems require Harvest to regularly conduct emergency response planning exercises to ensure its plans are effective. In 2008, Harvest undertook a complete update of its emergency response plan including the establishment of an emergency command center and corporate emergency response team. This team is well prepared for incidents as was demonstrated in our team's effective response to an oil spill at our Suffield area that garnered media attention.

Harvest's Upstream Manager of Environment, Health and Safety is responsible to monitor regulatory requirements and when required, implement appropriate compliance procedures and to cause our operations practices to be carried out in accordance with the applicable environmental requirements with adequate safety precautions. The manager of Environment, Health and Safety works closely with our Vice-President Operations to ensure company policies and practices are implemented and appropriate auditing is undertaken. The Reserves, Safety and Environmental Committee of Harvest Operations' Board of Directors quarterly reviews the results of these internal programs. Although the existence of these controls cannot guarantee total compliance with environmental laws, rules and regulations, Harvest believes that its operations are in material compliance with the applicable requirement.

In 2008, Harvest completed the installation of gas conservation projects in Hay River and its Lloydminster Heavy Oil Region which will significantly reduce both flaring and venting of gas in 2009. In Hay River there will be an estimated 60% reduction in flaring with an additional reduction expected by year end. In addition, Harvest completed 55 well-site reclamations which were submitted for certification and has over 200 ongoing reclamation projects that will continue to reduce the environmental impact of our operations.

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, including weather 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 20 to Harvest's consolidated financial statements for the year ended December 31, 2008 and under the heading "Cash Flow Risk Management" in Harvest's management discussion and analysis for the year ended December 31, 2008 both of which have been filed on SEDAR at www.sedar.com. Both Note 20 of Harvest's audited consolidated financial statements for the year ended December 31, 2008 and the "Risk Management, Financing and Other" discussion in Harvest's management discussion and analysis for the year ended December 31, 2008 are incorporated herein by this reference.

Industry Conditions

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, all of which should be carefully considered by investors in the petroleum and gas industry. 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 we are 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. These indices are generated at various sales points depending on the commodity and are reflective of the current value of the commodity adjusted for quality and locational differentials. While these indices tend to track industry reference prices (i.e. West Texas Intermediate crude oil at Cushing, Oklahoma or natural gas at Henry Hub, Louisiana), some variances can occur due to specific supply-demand imbalances. These differentials can change on a monthly or daily basis depending on the supply-demand fundamental at each location as well as other non-related changes such as the value of the Canadian dollar and the cost of transporting the commodity to the pricing point of the particular index.

The producers of crude oil are entitled to negotiate sales contracts directly with purchasers, with the result that the market determines the price of crude oil. 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 export 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.

The price of natural gas is determined by negotiation between buyers and sellers. 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 m^3/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.

Pipeline Capacity

Although pipeline expansions are ongoing, pipeline capacity is an important consideration and may impact the oil and natural gas industry by limiting the ability to export oil and natural gas.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, United States of America and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada-United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period or in such other representative period as the parties may agree); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements provided, in the case of export-price requirements, prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

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.

In November 2003, the Tax Act was amended to replace the previously available resource allowance deduction with full deductibility of crown royalties. In addition, the percentage of Alberta Royalty Tax Credit required to be included in federal taxable income was changed from 0% to 12.5% in 2004, 17.5% in 2005, 32.5% in 2006, 50% in 2007, 60% in 2008, and will be 70% in 2009, 80% in 2010, 90% in 2011, and 100% in 2012 and beyond.

Alberta

On October 25, 2007, the Government of Alberta (the "Government") released its New Royalty Framework (the "NRF") which became effective on January 1, 2009. Conventional oil royalties will be set by a single sliding rate formula containing separate elements that account for oil price and well production, with new royalty rates ranging up to 50% (previously 35% and a vintage tier structure) and rates capped when oil prices reach $120 Cdn per barrel (previously approximately $30/barrel). Natural gas royalties will also be set by a single sliding rate formula, with royalty rates ranging from 5% to 50% (previously 5% to 35% and a vintage tier structure) and rates capped when natural gas prices reach $17.75 Cdn per gigajoule (previously approximately $3.70/GJ). Oil sands base royalty rate will start at 1%, and increase 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%. In addition, the Government has included a Deep Gas Well Drilling program, a Deep Exploratory Oil Well program and is maintaining the Enhanced Oil Recovery and Innovative Energy Technology incentive programs. Generally, under the NRF and in the current commodity price environment, Harvest anticipates that we will pay lower royalties on most of our wells as they will be considered to be low productivity wells which continue to attract favourable royalty treatment.

Effective November 19, 2008, the Government introduced a new program of transitional royalty rates on new natural gas or conventional oil wells drilled at depths between 1,000 and 3,500 metres until the end of 2013. Companies have the one-time option of selecting the transitional royalty rates or the rates under the NRF. All Alberta wells are required to move to the NRF beginning on January 1, 2014.

On March 3, 2009, the Government of Alberta announced a new three-point stimulus plan:

- Drilling royalty credit for new conventional oil and natural gas wells – effective for wells spud on or after April 1, 2009, this one-year program will provide a $200 per-metre-drilled royalty credit, with the maximum credit determined on a sliding scale based on the individual company's total Alberta-based 2008 Crown oil and gas production.
- Royalty rate cap for new conventional oil and natural gas wells – effective April 1, 2009, this program will provide a maximum 5% royalty rate for the first 12 months of production, 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, 2010.
- Abandonment and reclamation fund – the province 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.

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 October 1, 2002, Saskatchewan introduced changes to royalty rates on associated natural gas, a modified system of incentive volumes and rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002 and fourth tier royalty status.

On March 23, 2005, the Government of Saskatchewan passed legislation to subject trusts to their Corporation Capital Tax Resource Surcharge (the "**Resource Surcharge**") with an effective date of April 1, 2005. The Resource Surcharge is calculated based on the applicable oil and natural gas revenues earned in Saskatchewan at the following rates. Prior to this legislation, the Resource Surcharge did not apply to trusts earned oil and gas revenues in Saskatchewan.

	Rates on Wells Drilled	
Effective date	Prior to October 1, 2002	After October 1, 2002
April 1, 2005	3.60%	2.00%
July 1, 2006	3.30%	1.85%
July 1, 2007	3.10%	1.75%
July 1, 2008	3.00%	1.70%

British Columbia

Royalties in British Columbia follow a similar methodology to Alberta and Saskatchewan. The amount payable in respect of crude oil depends on the type, value, quantity produced in a month and vintage. Vintage categories are old, new and third tier. 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 posted 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-conservation gas.

In 2003, British Columbia announced changes to royalty rates for low productivity natural gas to enhance marginally economic resource plays, and royalty credits for deep gas exploration, summer drilling and infrastructure development.

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 from 2 years 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.

Environmental Regulation

The oil and natural gas industry is currently 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 be 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.

Environmental legislation in the Province of Alberta has been consolidated into the Environmental Protection and Enhancement Act (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the Oil and Gas Conservation Act (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the Climate Change and Emissions Management Amendment Act came into effect on July 1, 2007. Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund. Industries can either choose one of these options or a combination thereof. The Corporation will be committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. The Corporation believes that it is in material compliance with applicable environmental laws and regulations. The Corporation also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

In January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for in situ oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage.

British Columbia's Environmental Assessment Act became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process. On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining the Province's strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and gas sector. Among the changes to be implemented are: (i) a new Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) the new Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves. Furthering these initiatives, on February 19, 2008 the provincial Government announced that starting on July 1, 2008, provided the legislation is approved; a revenue-neutral carbon tax will be applied to all fossil fuels used in the Province. The tax would be phased in, and the initial rate would be based on CO_2e of \$10 per tonne for the first six months of 2009 and \$15 per tonne for the last six months of 2009, following \$5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the Government would receive otherwise.

In December, 2002, the Government of Canada ratified the Kyoto Protocol ("**Protocol**"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the federal government (see below), that the Kyoto target of 6% below 1990 emission levels will be enforced in Canada. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the

Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. There are mandatory reductions of 18% from the 2006 baseline starting in 2010 and an additional 2% in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oils sands production, petroleum refining, natural gas pipelines and upstream oil and gas the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be granted a 3-year grace period during which no emissions intensity targets will apply. Targets will begin to apply on the fourth year of commercial operation and the baseline will be the third year's emissions intensity, with a 2% continuous annual emission intensity improvement required. The definition of new facility also includes greenfield facilities, major expansions constituting more than a 25% increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and in-situ production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of carbon dioxide equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of carbon dioxide equivalent per upstream oil and gas facilities; and (iii) 10,000 BOE/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of carbon dioxide equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as mentioned above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either cancel the offset credits or bank them for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 Mt worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on the Corporation and its operations and financial condition at this time.

DOWNSTREAM BUSINESS

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 bbls/d nameplate capacity and a marketing division with 64 gasoline outlets, a retail heating fuels business and a commercial and wholesale petroleum products business, all located in the Province of Newfoundland and Labrador. The daily sales volume of our retail marketing and wholesale division averages over 14,000 barrels, representing approximately 20% of the Newfoundland market.

Brief History

The construction of the Refinery commenced in 1971 with the crude oil distillation unit commissioned in late 1973 and most other process units started-up in 1974. The Refinery was shut down two years later as the owner filed for bankruptcy protection during the oil price shock. In 1980, Petro-Canada purchased the Refinery but did not operate it, and in late 1986, sold the Refinery to a private company. From 1986 through 1994, the new owner invested approximately $132 million in the Refinery including the construction of a new hydrogen unit. On April 24, 1994, the Refinery experienced a fire at the vacuum tower and, as a consequence, the entire facility was again shut down as the owner was unable to finance the restoration of the Refinery.

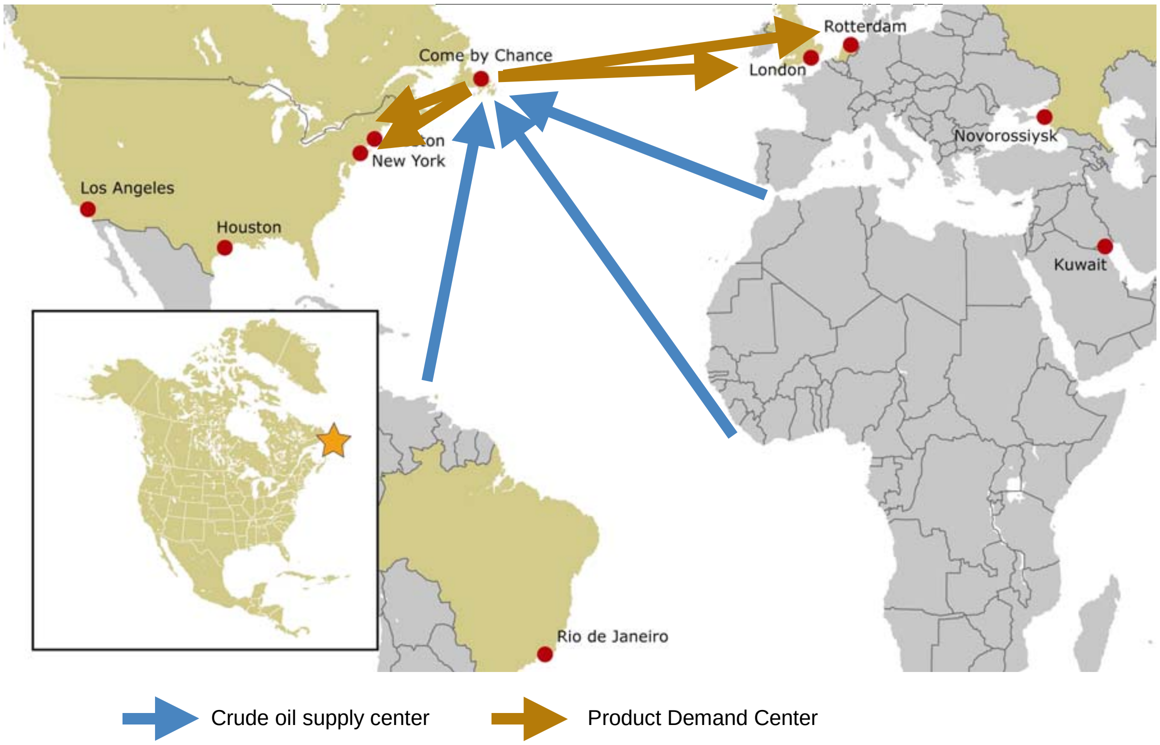
The Vitol Refining Group B.V. acquired the Refinery in August 1994 and commenced a major restoration and successfully commissioned the Refinery in late 1994. Since then, more than US$400 million was invested to maintain, upgrade and expand the facility prior to our acquisition of the Refinery in late 2006. These investments significantly improved the Refinery's operating performance in terms of refinery throughput, reliability, saleable yield, product quality, safety and environmental performance. On October 19, 2006, Harvest acquired North Atlantic Refining Limited.

In 2008, the Refinery averaged 103,497 barrels per day, up 5% from 98,617 barrels per day in the prior year. Production in 2007 was impacted by a planned maintenance turnaround while operations in 2008 were somewhat tempered by efforts to optimize refining margins by minimizing the production of high sulphur fuel oil ("HSFO") early in the year and due to fouling of heat exchangers late in the year.

Overview of Refinery Operations

The Refinery's feedstocks are delivered by ship primarily from Iraq, Russia and Venezuela. The Refinery produces high quality gasoline, ultra low sulphur diesel, jet fuel and furnace oil, and high sulphur fuel oil ("HSFO"). Approximately 10% of our refined products are sold in the Province of Newfoundland and Labrador while approximately 90% are sold in the U.S. east coast markets, such as Boston and New York City, Europe or further abroad when economics warrant the increased shipping charges. The Refinery enjoys a significant transportation advantage as it operates a deep water docking facility and has approximately seven million barrels of tankage including six 575,000 barrel crude tanks enabling the receipt of crude oil transported on very large crude carriers which typically result in significantly lower per barrel transportation charges. Harvest's downstream assets include dock facilities for off-loading crude oil feedstock and for loading refined products. The dock facilities handle approximately 220 vessels each year with Harvest owning and operating two tugboats to assist with berthing and unberthing tankers.

The following map illustrates the refinery's proximity to the key Atlantic crude oil and product shipping lanes.



Distance from Come by Chance, Newfoundland, Canada to:	Sailing Days
Boston, U.S.	3
New York, U.S.	3
London, U.K.	7
Rotterdam, Netherlands	7
Houston, U.S.	8
Novorosslysk, Russia	14
Rio de Janeiro, Brazil	14
Los Angeles, U.S.	18
Kuwait City, Kuwait	24

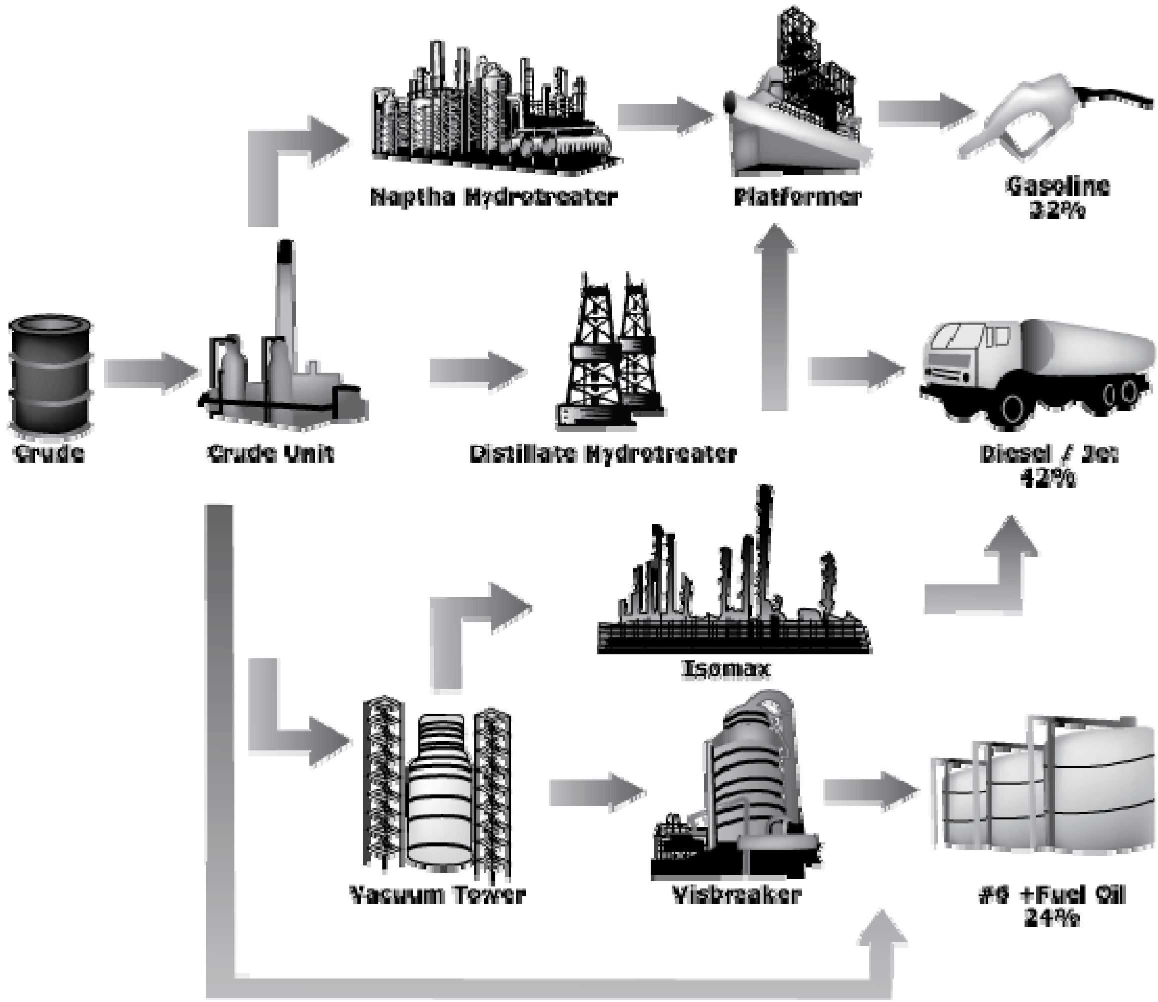
Refinery Feedstock

Crude oil and other feedstocks are delivered to the Refinery via vessels capable of carrying over 2 million barrels of crude oil. Normally, there are approximately 20 days of crude oil feedstock in tankage at the Refinery to mitigate the effects of any supply disruptions. Over the past three years, the origin of the feedstock has been as follows:

	2008 (Mbbls)	2007 (Mbbls)	2006 (Mbbls)
Iraqi	21,218	23,230	25,535
Venezuelan	7,102	5,180	4,258
Russian	5,973	3,367	1,148
Other	3,586	4,218	3,667
Total Feedstock	**37,879**	**35,995**	**34,608**
As % of nameplate capacity	**90%**	**86%**	**82%**

Refinery Processing

The following is a schematic of the primary process flow of the Refinery.



Refined Products

Over the past three years, the Refinery has produced the following refined products:

	2008	2007	2006
	(Mbbls)	(Mbbls)	(Mbbls)
Gasoline products	12,068	11,515	11,434
Distillate products	15,668	14,406	14,270
High sulphur fuel oil(“HSFO”)	9,952	9,843	9,633
Total Products	37,688	35,764	35,337
Total Liquid Yield (as a % of feedstock)	100%	99%	102%

Operations Reliability

Improving the reliability of the Refinery has been a major focus with significant capital expenditures and a change in maintenance philosophy. Our maintenance philosophy has evolved to one that emphasizes long term solutions to reliability issues through the conduct of rigorous analyses regarding the root cause of reliability issues. Of particular note, we have developed an advanced Equipment Integrity Program whereby remaining equipment life calculations are utilized to determine equipment turnaround schedules and ensuring that equipment is repaired or replaced before failure occurs.

Supply and Offtake Agreement

Concurrent with its acquisition of North Atlantic in 2006, Harvest entered into the SOA with Vitol Refining S.A. ("**Vitol**"). The SOA provides that the ownership of substantially all crude oil and other feedstocks and refined product inventory at the Refinery be retained by Vitol and that Vitol be granted the right and obligation to provide crude oil feedstock and other feedstocks for delivery to the Refinery as well as the right and obligation to purchase all refined products produced by the Refinery. The SOA also provides that Vitol will receive a time value of money amount (the "**TVM**") reflecting the cost of financing the crude oil and other feedstocks and sale of refined products as the SOA requires that Vitol 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 provides Harvest 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, we, in consultation with Vitol, request a certain slate of crude oil and other feedstocks and Vitol is be obligated to provide the feedstocks in accordance with the request. The SOA includes a feedstock transfer pricing formula that aggregates the pricing formula 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 plus a fee of US$0.08 per barrel. The purpose of the operational price risk management contracts is to convert the fixed price of crude oil feedstock purchases to floating prices for the period from the purchase date through to the date the refined products are sold to Harvest to allow "matching" of crude oil feedstock purchases to refined product sales thereby mitigating the gross margin risk between the time crude oil feedstocks are purchased and the sale of the refined products.

The SOA requires that Vitol 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 effective January 20, 2008, all of our HSFO, and provides a product purchase pricing formula that aggregates a deemed price based on the current Boston and New York City markets less the deemed costs of transportation, insurance, port fees, inspection charges and similar costs deemed to be incurred by Vitol, plus the TVM component. The TVM component reflects an effective interest rate of 350 basis points over the London Inter Bank Offer Rate ("**LIBOR**").

The SOA may be terminated by either party at any time by providing notice of termination no later than six months prior to the desired termination date or if the Refinery is sold in an arms length transaction, upon 30 days notice prior to the desired termination date. Further, the SOA 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 entire agreement or the right and obligation to provide feedstocks, Harvest will be required to purchase the related feedstocks and refined product inventory, respectively, at the prevailing market prices.

Vitol is an indirect wholly-owned subsidiary of the Vitol Refining Group B.V. ("**Vitol Group**"), a privately owned worldwide marketer of crude oil providing oil trading and marketing services to upstream producers through to downstream retailers of petroleum products. In 2005, the Vitol Group handled over US$80 billion of crude oil, fuel oil, gasoline and related products. With headquarters in Rotterdam, the Netherlands and Geneva, Switzerland, the Vitol Group has trading entities in Houston, London, Bahrain and Singapore which provide 24 hour coverage of all the world's oil markets. In the crude oil sector, the Vitol Group has developed a worldwide reputation as a reliable business partner. In addition, the Vitol Group is one of the largest independent gasoline traders in the world.

Marketing Division

Our marketing division (the "**Marketing Division**") is headquartered in St. John's, Newfoundland and is comprised of five business segments: retail gasoline, retail heating fuels, commercial, wholesale and bunkers. Since 2001, in the Province of Newfoundland and Labrador, 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 Product 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 is adjusted monthly based on the New York Harbour benchmark price for these products, however, the prices may be adjusted more frequently when circumstances warrant.

Retail Gasoline Business

Our retail gasoline business operates 61 retail gasoline stations and 3 commercial cardlock locations with 38 locations branded as "North Atlantic" and 15 locations branded as "Home Town" (a secondary brand for small market areas) with the remaining 11 locations unbranded. Most locations include a convenience store which is independently operated. In 2008, the volume of gasoline and diesel sold at these retail locations represented a market share of approximately 20% of the Newfoundland market. The major competitors in the Newfoundland market are Irving Oil, Imperial Oil and Ultramar.

Retail Heating Fuels Business

Our retail heating fuels business delivers furnace oil and propane to approximately 20,000 residential heating and commercial customers throughout Newfoundland with about 90% of the demand for furnace oil, 9% for propane and 1% for kerosene. North Atlantic is a full service residential heating supplier providing a furnace parts maintenance replacement program, emergency burner service and heating system installations from five "Home Heating" stores. North Atlantic's installation and emergency burner service is provided by independent contractors, as is its bulk hauling.

Commercial Business

North Atlantic delivers distillates, jet fuel, propane and No. 6 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.

Overview of Management Structure

Effective in November 2007, Brad Aldrich was appointed Harvest’s Chief Operating Officer, Downstream. Mr. Aldrich is a senior executive with extensive management experience in petroleum refining and marketing, supply and trading, price risk management, transportation and distribution, and production planning. He has over 27 years of industry experience, including direct responsibility for Clark Refining (an independent petroleum refining and petrochemicals organization) and 12 years of increasing responsibilities with Conoco in their downstream operations. Most recently, Mr. Aldrich held the position of Vice President of Production with Yukos Oil Company, a Russian petroleum company, where he led operations at 11 plants and managed its multi-billion dollar refinery modernization program.

Under Mr. Aldrich’s leadership, our downstream operations are managed by senior level managers in the following functional areas:

- Production and Maintenance;
- Planning, Economics and Engineering Services;
- Marketing;
- Supply and Logistics;
- Finance and Controls; and
- Human Resources.

Employees and Labour Relations

Our downstream operations have approximately 519 full-time employees of which 67% are unionized and approximately 48 part-time employees of which 69% 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. These collective agreements have a three year term ending December 2010. See "*Risk Factors*".

We maintain a number of employee benefit programs for our employees including basic life insurance and accidental death and dismemberment insurance, extended healthcare and dental coverage, as well as a defined benefit and defined contribution pension plans and we provide certain post retirement health care benefits which cover substantially all employees and their surviving spouses. At December 31, 2008, the pension plan and other benefit plan obligations exceeded the pension plan and other benefit plan funding by approximately $10.8 million. For additional information, refer to Note 19 in our audited consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com.

Environment, Health and Safety Policies and Practices

Our downstream business has an active and comprehensive Integrated Management System to promote the integration of safety, health and environmental awareness into our 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 seventh consecutive year. In 2008, the Refinery was in compliance with Provincial Air Quality and Federal Effluent Regulations.

Industry Conditions

The petroleum refining industry is subject to extensive controls and regulations governing its operations (including marine transportation, product specifications, refining emissions and market pricing) 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 our 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 we are unable to predict what additional legislation or amendments may be enacted.

An oil refinery is a manufacturing facility that uses crude oil and other feedstocks as a raw material 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: the different types of hydrocarbons in crude oil are separated, the separated hydrocarbons are converted into more desirable or higher value products, or chemicals treat 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.

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 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.

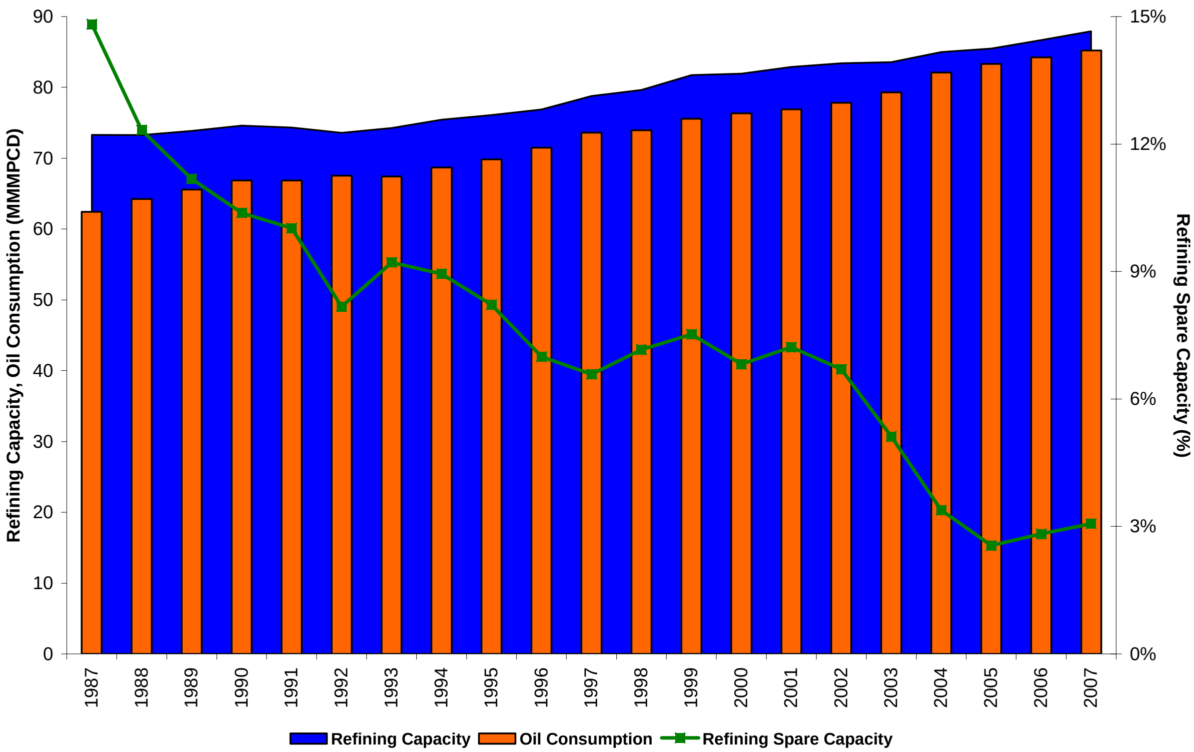
Demand for refined oil products has significantly increased in recent years due to the industrialization of countries such as China, India and Brazil. Demand for gasoline and diesel continues to rise due to rising transportation usage. In the United States, while demand for gasoline continues to be strong, the diesel demand continues to strengthen and in Europe, diesel demand continues to outgrow its production capability. Over the long term, refining margins and crude oil prices are typically correlated as both are driven by the demand for refined petroleum products.

Until recently, global investment in refining capacity has been restrained as weak refining margins have not supported investment in either capacity increases at existing refineries or the construction of new refineries. From the early 1980's through the early 1990's, global refining capacity fell as uneconomic refineries were shut down in the face of low margins. Since then, global refining capacity has grown, predominantly through capacity creep, but at a pace insufficient to keep up with the growth in global demand for refined products. Given the lead-time required to engineer and construct new refining facilities and resistance to refineries being built in many areas, it is expected that the global refined product market should be strong for several years.

In addition to the global tightening of the refined product supply/demand balance, global crude oil supply has become heavier and higher in sulphur content. The incremental production from most OPEC countries and many other export producers has tended to be sour crude, containing more sulphur, while incremental crude oil production from Canada, Venezuela and Mexico has been both heavy and sour. Because global refining capacity is largely configured to process the higher gravity and lower sulphur crude oil, lower gravity and more-sour crude oil has increasingly been sold at a discount to the lighter and sweeter crude oil. At the same time, refiners have turned to lighter and sweeter crude oil as feedstocks to meet the lower sulphur fuel specifications in North America and Europe resulting in a greater discount for sour crude oil. Notwithstanding the widening quality differentials, the higher prices paid for all crude oil has accelerated the development of heavier gravity and higher sulphur crude oil production. As a result, quality differentials are expected to remain wide providing a significant economic benefit for those refiners able to process lower quality crude oil into higher value refined products.

As presented in the following graph, moderate creep in refinery capacity has not kept pace with the demand for crude oil resulting in the spare refining capacity tightening from over 15% in 1987 to 3% in 2007.

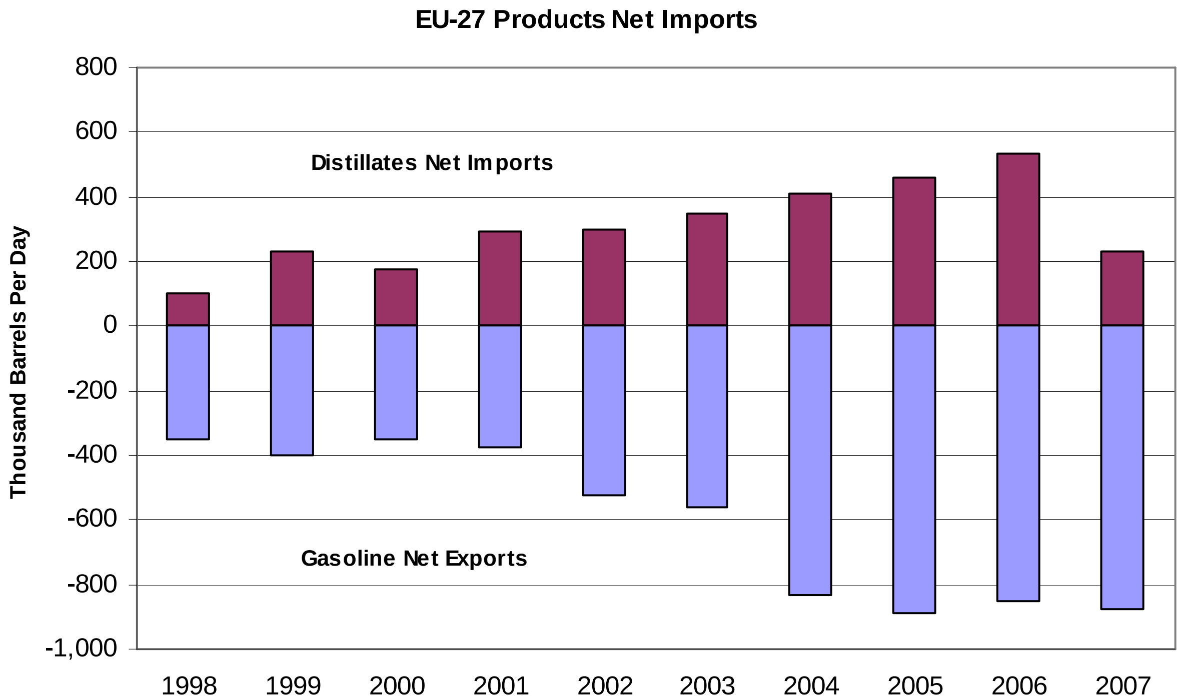
Global Refining Capacity and Crude Demand



Source: Energy Information Administration

The U.S. imports approximately 2.5 million bbl/d of refined products, representing approximately 12% of its total refined product demand. With the recent strength in refined product margins, the U.S. refiners have begun to more aggressively increase capacity, and by 2010, capacity growth is expected to approximately equal to demand growth thereby maintaining a refining supply-demand balance deficiency of approximately 2.5 million bbl/d which will likely be met by the importing of refined products. However, anticipating that refining capacity in most major supply sources appear fully committed, US refining margins will need to remain strong to attract imports from more distant locations.

Relative to the U.S. import of refined products, the European refined product markets over the past ten years have been characterized as an ever increasing import of distillates, primarily low sulphur diesel, and an increase in the export of gasoline products. Typically, the North American motor fuels market is dominated by gasoline and to a lesser extent diesel, whereas the European motor fuels market is predominately diesel fuel.



Source: Energy Information Administration

RISK FACTORS

Both Harvest's upstream operations and its downstream operations are conducted in the same business environment as most other operators in the respective businesses. However, the Harvest Energy Trust structure is significantly different than that of a traditional corporation with share capital and there are certain unique business risks of Harvest's structure. We have segregated Harvest's business risks into those generally applicable to upstream operators as well as downstream operators and those applicable to royalty trusts as well as those risks particular to Unitholders resident in the United States and other non-residents of Canada.

The following is a summary of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Annual Information Form.

Risks Related to Harvest's Upstream Operations

Volatility of Commodity Prices and Foreign Exchange Risk

The Trust's cash flow from its upstream operations is dependent on its NPI and the Direct Royalties which are dependent on the prices received from the sale of petroleum, natural gas and natural gas liquids production. Prices for petroleum, natural gas and natural gas liquids have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil producing regions, which are beyond the control of Harvest Operations or the Trust. 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/US currency exchange rate could have a material adverse effect on the Trust's cash from operating activities, financial condition and the cash available for distribution to Unitholders as well as funds available for the development of its Operating Subsidiaries petroleum and natural gas reserves. From time to time, Harvest Operations may manage the risk of changes in commodity prices and currency exchange rates by entering into commodity price risk management contracts and/or currency exchange contracts.

To the extent that Harvest Operations or the Trust engage in risk management activities related to commodity prices and currency exchange rates, it will be subject to counterparty risk.

Crude Oil Differentials

At the end of 2008, Harvest's production was approximately 53% light and medium gravity crude oil, 19% heavy oil and 28% 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 its heavy oil and could have a material adverse effect on the Trust's cash from operating activities, financial condition and the cash available for distribution to Unitholders as well as funds available for the further development of its oil 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 the control of Harvest Operations.

Operational Matters

The operation of oil and natural gas wells involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected and/or dangerous conditions resulting in damage to Harvest Operation's assets and potentially assets of third parties. Harvest Operations 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 Trust's Operating Subsidiaries may become liable for damages arising from such events against which it cannot insure or which it may elect not to insure. Costs incurred to repair such damage or pay such liabilities will reduce the Trust's cash flow from its NPI.

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 Operations operates the majority of its Properties, there is no guarantee that it will remain operator of such Properties or that it will operate other Properties that may be acquired.

A significant portion of Harvest's operating expenses are electrical power costs. Since 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. Generally, this volatility has resulted in higher electrical power prices which negatively impact Harvest's operating expenses, and in turn, the Trust's cash from operating activities and cash available for distribution to Unitholders. To mitigate its exposure to the volatility in electrical power prices, Harvest Operations may enter into fixed priced forward purchase contracts for a portion of its electrical power consumption in Alberta. In respect of its 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.

Although satisfactory 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 the claim of an Operating Subsidiary to certain Properties. A reduction of cash flow from a NPI or income from Direct Royalties payable to the Trust could result from such circumstances.

Harvest's ability to market petroleum and natural gas from its wells also depends upon numerous other factors beyond its 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 diluent 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 favourable prices for the petroleum and natural gas it produces.

Reserve Estimates

The reserve and recovery information contained in Harvest's Reserve Report are complex estimates and the actual production and ultimate reserves recovered from the Properties may differ from the estimates prepared by the Independent Reserve Engineering Evaluators.

The Reserve Value of the Properties as estimated by Independent Reserve Engineering Evaluators is based in part on cash flows to be generated in future years as a result of future capital expenditures. The Reserve Value of the Properties as estimated by the Independent Reserve Engineering Evaluators will be reduced to the extent that such capital expenditures on the Properties do not achieve the level of success assumed in such engineering reports.

Depletion of Reserves (Sustainability)

The Trust's cash from operating activities and cash available for distribution to Unitholders, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. Harvest will not be reinvesting to the same extent as other industry participants as it makes cash distributions to its Unitholders. Accordingly, absent additional capital investment from other sources, production levels and reserves attributable to the Properties will decline.

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

Failure to Realize an Adequate Rate of Return on Prices Paid for Properties

The prices paid for acquisitions were based, in part, on engineering and economic assessments made by independent engineers. 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 and 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 the control of Harvest. In particular, changes in the prices of and markets for petroleum and natural gas from those anticipated at the time of making acquisitions will affect the value of the Trust Units. 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 the Properties.

Changes in Legislation

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 be changed in a manner which adversely affects Harvest.

Environmental Concerns

The petroleum and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines on the Operating Subsidiaries or the issuance of clean up orders on the Properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on Harvest. Additionally, the potential impact of Canada's ratification of the Kyoto Protocol on Harvest's business and cash from operating activities and cash available for distribution to Unitholders with respect to instituting reductions of greenhouse gases is difficult to quantify at this time. See "Other Upstream Business Information – Environment, Health and Safety Policies and Practices" and "Other Upstream Business Information – Industry Conditions".

Competition

There is strong competition relating to all aspects of the petroleum and natural gas industry. The Operating Subsidiaries and/or the Trust 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 its operations with a substantial number of other petroleum and natural gas organizations, many of which may have greater technical and financial resources than the Operating Subsidiaries and/or the Trust, individually or combined. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining 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.

Potential Conflicts of Interest

Circumstances may arise where members of the Board of Directors or officers of Harvest Operations are directors or officers of corporations which are in competition to the interests of Harvest. No assurances can be given that opportunities identified by such board members or officers will be provided to the Operating Subsidiaries and/or the Trust. See "Conflicts of Interest".

Risks Related to Harvest's Downstream Operations

Investment in North Atlantic

Harvest's investment in North Atlantic is in the form of interest bearing notes and interests in various partnerships and trusts, and accordingly, Harvest is dependent upon the ability of North Atlantic to pay its interest obligations under the notes and distributions from the various partnerships. North Atlantic's ability to pay interest and distributions is entirely dependent on its operations and assets which will be impacted by risks typical of refinery and marketing operations.

Volatility of Commodity Prices

Our 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 we are 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 demand for crude oil and other 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;
- 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;
- 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 we compete; and
- The development and marketing of competitive alternative fuels.

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 refined products manufactured from the feedstock. Harvest does not produce crude oil that can be economically transported to our refinery and must purchase all of its crude oil feedstock at prices that fluctuate with worldwide market conditions and this could significantly impact our earnings and cash flow. We also purchase refined products from third parties for sale to our customers and price changes during the period between purchasing and selling these products could also have a material adverse effect on our business and results of operations, as well as Harvest's financial condition and cash from operating activities.

We purchase 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. Our refinery's cost of electrical power has remained relatively constant averaging $0.041 per kilowatt hour in 2005 as compared to $0.039 in 2008. 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 our business and results of operations, as well as Harvest's financial condition and the cash from operating activities.

Fluctuations in the Canada-United States Exchange Rates

The prices for crude oil and refined products are generally based on market prices in U.S. dollars while our 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 a 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 be sufficient to effectively cover all of our exposure.

Disruptions in the Supply of Crude Oil and Delivery of Refined Products

Our refinery receives all of its crude oil feedstock and delivers approximately 90% of its refined products via water borne vessels including very large crude carriers capable of handling over 2 million barrels of crude oil. In addition to environmental risks of handling such vessels discussed below, we 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 an adverse material effect on our business and results of operations, as well as Harvest's financial condition and cash from operating activities.

Since our acquisition of North Atlantic, over 75% of our crude oil feedstock has been from sources in Iraq. We do not maintain supply commitments with any of our crude oil producers. To the extent that crude oil producers, particularly in Iraq, reduce the volume of crude oil produced as a result of declining production or competition or otherwise, our business, financial condition and results of operations may be adversely affected to the extent that we are not able to find a substantial amount and similar type of crude oil. Further, we have no control over the level of development in the fields that currently produce the crude oil we process at our 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.

We are relying on the creditworthiness of Vitol Refining S.A. for our purchase of crude oil feedstock pursuant to the Supply and Offtake Agreement and rely on the creditworthiness of Harvest to enter into price risk management contracts to reduce exposure to adverse fluctuations in the prices of crude oil and refined products. Accordingly, should the creditworthiness of Vitol Refining S.A. and/or Harvest deteriorate, crude oil producers and suppliers as well as financial counterparties may change their view on contracting with us for the supply of crude oil and/or price risk management contracts, respectively, and induce them to shorten the payment terms or require additional credit support, such as letters of credit. Due to the large dollar amount of credit associated with the volume of crude oil purchases and long-term price risk management contracts, any imposition of more burdensome payment terms may have a material adverse effect on our financial liquidity which could hinder our ability to purchase sufficient quantities of crude oil to operate the Refinery at full capacity. In addition, if the price of crude oil increases significantly, the credit requirements to purchase enough crude oil to operate the Refinery at full capacity will also increase. A failure to operate the Refinery at full capacity could have an adverse material effect on our business and results of operations, as well as Harvest's financial condition and cash from operating activities.

Operational Risks

The Refinery is a single 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, our 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 our business and results of operations, as well as Harvest's financial condition and cash from operating activities.

Our 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 its equipment or third-party facilities, any of which can result in personal injury claims as well as damage to our properties and the properties of others. While we carry property, casualty and business interruption insurance, we do 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 our business and results of operations, as well as Harvest's financial condition and cash from operating activities. Currently, we have the opportunity and intend to consider opportunities to grow our business through the reconfiguration and enhancement of our refinery assets with the suite of expansion or de-bottlenecking projects. However, if unanticipated costs occur or our 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 our operations or funding available from debt financings will be available to meet our capital and operating requirements.

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 our storage tanks, or in connection with any facilities to which we send wastes or by-products for treatment or disposal, other than events for which we are indemnified, we 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 we may have to pay for releases or spills, or the amounts that we 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 our business and results of operations, as well as Harvest's financial condition and cash from operating activities.

We operate 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 our capacity to respond to a "worst case discharge" to a maximum 10,000 metric tonne oil spill. Our 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 our 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, we have contracted with the Eastern Canada Response Corporation to supplement our 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 we may be subject to a significant liability in connection with a discharge.

We have in the past operated service stations with underground storage tanks in the Province of Newfoundland and Labrador, and currently operate 13 retail service stations and 2 cardlock locations with underground storage tanks. We are 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 our 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 we maintain insurance in respect of such risks, there are no assurances that such insurance will be adequate to fully compensate for any liability we may incur if such risks were to occur.

Aviation Fuel Risks

We produce aviation fuels which involves inherent risks and subjects us to the provisions of Canadian Federal laws. Our product quality assurance programs are extensive; however, these procedures may not be sufficient to detect and prevent contaminants from entering into our aviation fuels which could result in aircraft engines being damaged and/or aircraft crashes. While we maintain insurance in respect of such risks, there are no assurances that such insurance will be adequate to fully compensate for any liability we may incur if such risks were to occur.

Environmental, Health and Safety Risks

Our operations and 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 we fail to comply with these regulations, we 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 our operations.

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

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 additional unanticipated expenditures. 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 our business and results of operations as well as Harvest's financial condition and cash from operating activities.

We are presently subject to litigation and investigations with respect to the use of MTBE and the delivery of contaminated sulphur (see "Legal Proceedings") and although indemnified by the previous owner, there is no assurance that such indemnity will be sufficient to offset our costs and liabilities. We may become involved in further litigation or other proceedings, or may be held responsible in any existing or future litigation or proceedings, the costs of which could be material.

Management Risks

Our future performance depends to a significant degree upon the continued contributions of our senior management team and key technical and operations employees. The loss of one or more members of our downstream senior management team or a number of key technical and operations employees could result in a disruption to our downstream operations. In addition, we face competition for these key individuals from competitors, customers and other companies operating in the refining industry and to the extent that we lose members of our senior management team or key technical and operations employees for any reason, we will be required to hire other personnel to manage and operate our downstream operations and we may not be able to locate or employ such qualified personnel on acceptable terms. As a result, the operating history of North Atlantic which has resulted in revenue and profitability may not be indicative of our future downstream operations, prospects and viability.

Employee Relations

We have approximately 519 full-time employees and 48 part-time employees in our downstream operations of which approximately 67% and 69%, respectively, are represented by the United Steel Workers of America pursuant to collective bargaining agreements. Although we have been able to negotiate a new three year contract in late 2007, we 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 our downstream business and results of operations as well as Harvest's financial condition and cash from operating activities.

Competition

We compete with a broad range of refining and marketing companies, including multinational oil companies. Because of their geographic diversity, larger and more complex refineries and greater resources, some of our competitors may be better able to better withstand volatile market conditions, to compete on the basis of price, to obtain crude oil in times of shortage and to bear the economic risks inherent in all phases of the refining industry than we are able to withstand.

Terrorist Attacks, Threats of Attacks or Acts of War

Our downstream business is affected by general economic conditions as well as fluctuations in consumer confidence and spending which can decline as a result of numerous factors outside of its control, such as terrorist attacks, threatened terrorist attacks or acts of war. Terrorist attacks, as well as events occurring in response to or in connection with them, including future terrorist attacks against Canadian or U.S. targets, rumours or threats of war, actual conflicts involving the military of Canada, the United States or their allies could cause trade disruptions impacting crude oil producers or refined products customers or energy markets generally, and may adversely impact our downstream business and results of operations as well as Harvest's financial condition and cash from operating activities.

Since the terrorist attacks of September 11, 2001, the Government of the United States of America has issued public warnings that energy-related assets (which could include our refinery) may be at greater risk of future terrorist attacks than other targets in Canada or the United States. Such occurrences could significantly impact energy prices, including prices for crude oil and refined products, which could have a material adverse effect on our downstream business and results of operations as well as Harvest's financial condition and cash from operating activities.

Risks Related to Harvest's Structure

Debt Service

As of March 24, 2009, Harvest has indebtedness of approximately $1.2 billion under its Extendible Revolving Credit Facility. In addition, letters of credit have been issued to third parties totalling approximately $1.3 million on behalf of Harvest Operations to secure services, primarily electric power, for its upstream operations. Harvest Operations has also issued US$250 million of $7^{7/8}$% Senior Notes due October 15, 2011 on which semi-annual interest payments are required. The Operating Subsidiaries have provided the lenders under its Extendible Revolving Credit Facility with security over all of Harvest's assets. If Harvest commits an event of default or the lenders demand repayment, the lenders may foreclose on and/or sell Harvest's assets free from, or together with, the NPI encumbrance.

Certain payments by the Operating Subsidiaries and the Trust's cash distributions to Unitholders are prohibited upon an event of default or demand for repayment under the Extendible Revolving Credit Facility. Any indebtedness of the Operating Subsidiaries to the Trust pursuant to the NPI and amounts payable to the Unitholders under the Trust Indenture are subordinate to payments required pursuant to the Extendible Revolving Credit Facility pursuant to subordination agreements between the Lenders, the Trust, and the Operating Subsidiaries. These subordination agreements may restrict the ability of the Operating Subsidiaries to pay amounts owing under the NPI to the Trust or pay interest or principal on any indebtedness owing to the Trust or other amounts owing to the Trust, and therefore may limit or eliminate the Trust's cash available for distribution to Unitholders.

Harvest must meet certain ongoing financial and other covenants under the Extendible Revolving Credit Facility. The covenants are customary restrictions on the Operating Subsidiaries' operations and activities, including restrictions on the incurring of indebtedness, the granting of security, the issuance of incremental debt and the sale of assets. Harvest is also subject to certain covenants under the note indenture respecting the $7^{7/8}$% Senior Notes, including limitations on the ability of Harvest to issue secured debt and to pay cash distributions to Unitholders.

Debt Repayment

Harvest is permitted to borrow funds to finance the purchase of assets, incur capital expenditures, repay other obligations and for working capital purposes. Borrowings of the Operating Subsidiaries may be repaid with funds received from the Trust. Debt service costs of the Operating Subsidiaries are deducted in computing income from the NPI payments and debt service costs of the Trust reduce the Trust's cash available for distribution to Unitholders. Variations in interest rates could result in significant changes in the amount required to be applied to debt service before payment of the NPI obligations and result in less cash available for distribution to Unitholders.

Interest and principal payable pursuant to the $7^{7/8}$% Senior Notes are payable in U.S. dollars. Harvest is permitted to borrow funds under its Extendible Revolving 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 Extendible Revolving Credit Facility and the $7^{7/8}$% Senior Notes, thereby reducing the Trust's cash available for distribution to Unitholders.

Access to External Capital Resources

The current global economic conditions, including disruptions in the international credit markets and other financial systems, the deterioration of global economic conditions, and the significant volatility in commodity prices resulting from the uncertainties over the supply and demand for commodities due to the current state of the global economy, have made it difficult to raise equity and debt on economically favourable terms. 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 or expand its petroleum and/or natural gas reserves as well as de-bottleneck its refinery operations will be impaired. To the extent Harvest is required to use additional cash from operating activities to fund capital expenditures or property acquisitions, the level of cash available to pay distributions to Unitholders may be reduced.

Variability of Cash Distributions

The Operating Subsidiaries may retain a portion of their cash flows from the Properties to facilitate the development of the Properties. Harvest believes this will assist in maintaining distributions over a longer period than would otherwise be the case if all cash flows from the Properties were paid to the Trust and subsequently distributed to the Unitholders. Future cash flows from such Properties may not be sufficient to fully recover the development costs and may not generate sufficient cash flows to allow the Operating Subsidiaries to maintain their NPI payments to the Trust resulting in a reduction in the Trust's cash available for distribution to Unitholders over the longer term.

Nature of Trust Units

Securities such as the Trust Units are hybrids in that they share certain attributes common to both equity securities and debt instruments. Trust Units are dissimilar to debt instruments in that there is no principal amount owing to Unitholders. The Trust Units do not represent a traditional investment in the petroleum and natural gas sector and should not be viewed by investors as shares in Harvest Operations or any of the Operating Subsidiaries. The Trust Units represent a fractional interest in the Trust. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. In addition, trusts are not defined as recognized entities within the definitions of legislation such as the *Bankruptcy and Insolvency Act (Canada),* the *Companies Creditors Arrangement Act (Canada)* and in some cases, the *Winding Up and Restructuring Act (Canada).* As a result, in the event of an insolvency or restructuring, a Unitholder's position as such may be quite different than that of a shareholder of a corporation.

The Trust's sole assets will be Permitted Investments, the NPI, the Direct Royalties and related contractual rights. The market price per Trust Unit will be a function of anticipated cash distribution to Unitholders, the value of the Properties acquired by Harvest and the Operating Subsidiaries' ability to affect the long-term cash flows from the Properties. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Trust to acquire suitable petroleum and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

Unitholder Limited Liability

The Trust Indenture provides that no Unitholder, in its capacity as such, shall incur or be subject to any liability in contract or in tort in connection with the Trust Fund or the obligations or affairs of the Trust or with respect to any act performed by the Trustee or by any other person pursuant to the Trust Indenture or with respect to any act or omission of the Trustee or any other person in the performance or exercise, or purported performance or exercise, of any obligation, power, discretion or authority conferred upon the Trustee or such other person hereunder or with respect to any transaction entered into by the Trustee or by any other person pursuant to the Trust Indenture. No Unitholder shall be liable to indemnify the Trustee or any such other person with respect to any such liability or liabilities incurred by the Trustee or by any such other person or persons or with respect to any taxes payable by the Trust or by the Trustee or by any other person on behalf of or in connection with the Trust. Notwithstanding the foregoing, to the extent that any Unitholders are found by a court of competent jurisdiction to be subject to any such liability, such liability shall be enforceable only against, and shall be satisfied only out of, the Trust Fund, and the Trust (to the extent of the Trust Fund) is liable to, and shall indemnify and save harmless any Unitholder against any costs, damages, liabilities, expenses, charges or losses suffered by any Unitholder from or arising as a result of such Unitholder not having any such limited liability.

The Trust Indenture also provides that all contracts signed by or on behalf of the Trust, whether by Harvest Operations, the Trustee, or otherwise, must (except as the Trustee or Harvest Operations may otherwise expressly agree with respect to their own personal liability) contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Notwithstanding the terms of the Trust Indenture, Unitholders may not be protected from liabilities of the Trust to the same extent a shareholder is protected from the liabilities of a corporation. Personal liability may also arise in respect of claims against the Trust (to the extent that claims are not satisfied by the Trust) that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities.

The activities of the Trust and Operating Subsidiaries are conducted and are intended to be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability to the Unitholders for claims against the Trust including by obtaining appropriate insurance, where available, for the operations of the Operating Subsidiaries and having contracts signed by or on behalf of the Trust include a provision that such obligations are not binding upon Unitholders personally.

The provinces of Alberta and Ontario have passed legislation providing unitholders of mutual fund trusts the same limited liability protections afforded to shareholders of corporations.

Investment Eligibility

If the Trust ceases to qualify as a "mutual fund trust" for purposes of the Tax Act, the Trust Units will cease to be qualified investments for registered retirement savings plans ("**RRSPs**"), registered retirement income funds ("**RRIFs**"), deferred profit sharing plans ("**DPSPs**") and registered education savings plans ("**RESPs**") (collectively, "Exempt Plans"). Where at the end of any month an Exempt Plan holds Trust Units that are not qualified investments, the Exempt Plan must, in respect of that month, pay a tax under Part XI.1 of the Tax Act equal to 1% of the fair market value of the Trust Units at the time such Trust Units were acquired by the Exempt Plan. In addition, where a trust governed by an RRSP holds Trust Units that are not qualified investments, the trust will become taxable on its income attributable to the Trust Units or any gains realized on a disposition of the Trust Units while they are not qualified investments.

Additional Financing

To the extent that external sources of capital, including the issuance of additional Trust Units, becomes limited or unavailable, the Trust's and the Operating Subsidiaries' ability to make the necessary capital investments to maintain or expand its petroleum and natural gas reserves will be impaired. To the extent the Trust or the Operating Subsidiaries are required to use cash flow to finance capital expenditures or property acquisitions, the cash available for distribution to Unitholders will be reduced.

Dilution

The Trust Indenture provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Board of Directors of Harvest Operations may determine. In addition, the Trust may issue additional Trust Units from time to time pursuant to the Trust Unit Rights Incentive Plan, Unit Award Incentive Plan and DRIP Plan as well as elect to settle the maturity of its Convertible Debentures. The possible issuance of these Trust Units could result in dilution to holders of Trust Units.

Reliance on Management of Harvest Operations

Unitholders will be dependent on the management of Harvest Operations in respect of the administration and management of all matters relating to the Properties, the NPI, the Direct Royalties, the Operating Subsidiaries, the Trust, and the Trust Units. Investors who are not willing to rely on the management of Harvest Operations should not invest in the Trust Units.

Return of Capital

Trust Units will have no value when reserves from the underlying assets of the Trust can no longer be economically produced and, as a result, cash distributions do not represent a "yield" in the traditional sense as they represent both return of capital and return on investment.

Net Asset Value

The net asset value of the Trust will vary dependent upon a number of factors beyond the control of management, including oil and natural gas prices as well as refining margins. The trading prices of the Trust Units is also determined by a number of factors which are beyond the control of management and such trading prices may be greater than or less than the net asset value of the Trust.

Changes to The Tax Act (Canada)

Income tax laws, such as the treatment of mutual fund trusts as well as the taxation of the Trust’s distributions to Unitholders, may be changed or interpreted in a manner that adversely affects the Trust and it Unitholders.

On June 22, 2007, the Government of Canada enacted legislation to apply a tax at the mutual fund trust level on distributions of certain income from publicly traded mutual fund trusts at rates of tax comparable to the combined federal and provincial corporate income tax rates in Canada and to treat such distributions as dividends to the unitholders. This legislation effectively implements the Government's plans to apply a tax to public mutual fund trusts commencing January 1, 2011. Management of Harvest believes that this tax legislation has reduced the value of its Trust Units and may also increase the cost of raising additional capital in the public markets. In addition, management of Harvest believes that these new tax measures have substantially eliminated any competitive advantage the Canadian energy trusts may have enjoyed in raising capital relative to their corporate peers.

Potential Conversion to a Corporation or Other Form of Entity

In light of the income tax legislative changes on June 22, 2007, Harvest continues to consider re-organizing its affairs in a manner that would minimizes taxes and other expenses payable with respect to the operation of the Trust and the Operating Subsidiaries. Currently, the management of Harvest is hesitant to make structural changes unless clear opportunities exist as prior to January 1, 2011, the present structure has value to its Unitholders.

Although at this time Harvest believes that its conversion to a corporation may be completed without creating a taxable event for Unitholders for either Canadian or United States federal income tax purposes, no assurances can be given that such a conversion will not give rise to an income tax liability.

Re-assessment of Prior Years' Income Tax Returns

From time to time, the Trust may take steps to organize its affairs in a manner that minimizes taxes and other expenses payable with respect to the operation of the Trust and the Operating Subsidiaries and maximizes the amount of cash available for distributions to Unitholders. If the manner in which the Trust structures its affairs is successfully challenged by taxation or other authorities, the amount of cash available for distribution to Unitholders may be affected.

In January 2009, the Canada Revenue Agency (the "CRA") issued a Notice of Reassessment to the Trust in respect of its 2002 through 2004 taxation years claiming past taxes, interest and penalties totalling $6.2 million. The CRA has adjusted the Trust's taxable income to include the net profits interest revenue to an accrual basis whereas the Trust's income tax filings have been prepared on a cash basis. In 2005, the Trust's income tax return was also prepared on a cash basis with no taxes payable and if prepared on an accrual basis of reporting consistent with the 2002 through 2004 taxation years as reassessed by the CRA, there would be taxes, interest and penalties owing of approximately $40 million. Although the management of Harvest and our legal tax advisors believe the reassessments by the CRA are not proper, there can be no assurances given that the Trust will not be required to pay approximately $46.2 million of taxes, interest and penalties which would reduce the amount of cash available for distribution to Unitholders.

Adoption of International Financial Reporting Standards

Effective January 1, 2011, Harvest will be required to adopt of the International Financial Reporting Standards ("IFRS") which may result in materially different reported financial results and may require amendments to its credit agreements to reflect the changes in accounting principles. As of the date of this AIF, Harvest has not yet determined its accounting policies under IFRS and is unable to quantify the impact IFRS will have on its financial statements. Prior to January 1, 2011, Harvest will continue to report its financial results in accordance with Canadian generally accepted accounting principles.

Risks Particular to Unitholders Resident in the United States and Other Non-Resident Unitholders

Unitholders Resident in the United States May be Subject to Passive Foreign Investment Company Rules

The Trust may be a passive foreign investment company for United States federal income tax purposes. To date, Harvest has not received advice that the Trust should not be considered a passive foreign investment company for the 2008 taxable year or previous taxable years. If the Trust were classified as a passive foreign investment company, Unitholders resident in the United States (other than most tax-exempt investors) would be subject to adverse tax rules. Under these adverse tax rules, Unitholders resident in the United States generally would be required to allocate any gain or excess distributions, which include any annual distributions other than in the first year the Unitholder held the Trust Units, that is greater than 125% of the average annual distributions received by that Unitholder in the three preceding taxable years or, if shorter, that Unitholder's holding period for Trust Units. The amount allocated to the current taxable year and any year prior to the first year in which Harvest was a passive foreign investment company would be taxed as ordinary income in the current year. The amount allocated to each of the other taxable years would be subject to tax at the highest rate of tax in effect for the applicable class of taxpayer for that year, and an interest charge for the deemed deferral benefit would be imposed with respect to the resulting tax attributable to each of the other taxable years. Holders will not be able to make a "qualifying electing fund" election or, with respect to the Trust's Operating Subsidiaries that were considered to be passive foreign investment companies, a "mark-to-market" election to protect themselves from these adverse consequences if Harvest were ultimately determined to be a passive foreign investment company. Unitholders resident in the United States are strongly urged to consult their own tax advisors regarding the United States federal income tax consequences of Harvest's possible classification as a passive foreign investment company and the consequences of such classification.

Unitholders Resident in the United States and Other Non-Resident Unitholders may be subject to Additional Taxations

The Tax Act and the tax treaties between Canada and other countries may impose additional withholding and other taxes on the cash distributions or other property paid by the Trust to Unitholders who are not residents of Canada and these taxes may change from time to time.

The Ability of Unitholders Resident in the United States and Other Non-Resident Unitholders to Enforce Civil Remedies May be Limited

The Trust is a trust organized under the laws of Alberta, Canada and Harvest's principal place of business is in Canada. The directors and officers of Harvest Operations are residents of Canada and most of the experts who provide services to Harvest are resident of Canada and all or a substantial portion of their assets and Harvest's assets are located within Canada. As a result, it may be difficult for investors in the United States or other non-Canadian jurisdictions (a "**Foreign Jurisdiction**") to effect service of process within such Foreign Jurisdiction upon such directors, officers and representatives of experts who are not residents of the Foreign Jurisdiction or to enforce against them judgements of courts of the applicable Foreign Jurisdiction based upon civil liability under the securities laws of such Foreign Jurisdiction, including United States federal securities laws or the securities laws of any state within the United States. In particular, there is doubt as to the enforceability in Canada against Harvest or any of its directors, officers or representative of experts who are not residents of the United States, in original actions or in actions for enforcement of judgement of United States courts of liabilities based solely upon the United States federal securities laws or the securities laws of any state within the United States.

DISTRIBUTIONS TO UNITHOLDERS

Cash available for distribution consists of any amounts received by the Trust pursuant to the NPI and the Direct Royalties, any interest or other income from Permitted Investments, dividends on the shares or other securities of the Operating Subsidiaries less all expenses and liabilities of the Trust, including the provision for interest due to the holders of Debentures, which are due or accrued and which are chargeable to income.

The actual amount of cash available for distribution depends on, among other things, the quantity and quality of crude oil, natural gas and natural gas liquids produced, prices received for such production, direct expenses of the Trust, taxes, operating costs, transportation and processing costs, capital expenditures, debt service costs, Crown and other royalties, other Crown charges, net contributions to the reclamation funds, net contributions by the Operating Subsidiaries to the Reserve Account, and general and administrative costs of the Trust and the Operating Subsidiaries. See "Risk Factors". The Operating Subsidiaries also have the discretion to incur debt or retain cash in order to modify seasonal and other variations in cash available for distribution. Unitholders may also receive distributions of the net proceeds received from sales of Properties to the extent Harvest Operations determines not to use those proceeds to acquire additional Properties.

Unitholders of record on a Record Date are entitled to receive a cash distribution which will become payable on the 15th day of the month following the Record Date, and if such date of payment is not a Business Day on the next Business Day after the 15th day of the month following the Record Date.

Pursuant to the provisions of the Trust Indenture all income earned by the Trust in a fiscal year, not previously distributed in that fiscal year, must be distributed to Unitholders of record on December 31. This excess income, if any, will be allocated to Unitholders of record at December 31 but the right to receive this income, if the amount is not determined and declared payable at December 31, will trade with the Trust Units until determined and declared payable in accordance with the rules of the Toronto Stock Exchange. To the extent that a Unitholder trades Trust Units in this period they will be allocated such income but will dispose of their right to receive such distribution. The following table sets forth the per Trust Unit amount of monthly cash distributions paid by the Trust for the periods indicated.

	2009	2008	2007	2006
January	$0.30	$0.30	$0.38	$0.35
February	$0.30	$0.30	$0.38	$0.35
March	$0.05(1)	$0.30	$0.38	$0.38
April		$0.30	$0.38	$0.38
May		$0.30	$0.38	$0.38
June		$0.30	$0.38	$0.38
July		$0.30	$0.38	$0.38
August		$0.30	$0.38	$0.38
September		$0.30	$0.38	$0.38
October		$0.30	$0.38	$0.38
November		$0.30	$0.30	$0.38
December		$0.30	$0.30	$0.38

Notes:

(1) The Trust announced on March 2, 2009 that a monthly cash distribution of $0.05 per Trust Unit will be paid on April 15, 2009 to Unitholders of record on March 23, 2009.

For further information on distributions to Unitholders see "Supplemental Capital Structure Information".

INTEREST PAID TO HOLDERS OF CONVERTIBLE DEBENTURES

Pursuant to the Debenture Indenture, including supplements thereto, the following table sets forth the interest rate and semi-annual payment dates for each series of Debentures.

Series of Debentures	Rate	Semi-Annual Payment Dates	Maturity Date
9% Debentures Due 2009	9%	May 31 and November 30	May 31, 2009
8% Debentures Due 2009	8%	March 31 and September 30	September 30, 2009
6.5% Debentures Due 2010	6.5%	June 30 and December 31	December 31, 2010
10.5% Debentures Due 2008 (1)	10.5%	January 31 and July 31	January 31, 2008
6.40% Debentures Due 2012	6.4%	April 30 and October 31	October 31, 2012
7.25% Debentures Due 2013	7.25%	March 31 and September 30	September 30, 2013
7.25% Debentures Due 2014	7.25%	February 28 and August 31	February 28, 2014
7.50% Debentures Due 2015	7.5%	May 31 and November 30	May 31, 2015

Notes:

(1) The 10.5% Debentures Due 2008 matured on January 31, 2008 and the $24.3 million principal amount was settled on maturity with the issuance of 1,166,593 Trust Units.

GENERAL DESCRIPTION OF CAPITAL STRUCTURE

Harvest Energy Trust was created, and Trust Units issued, pursuant to the Trust Indenture. The Trust Indenture provides for the administration of Harvest, the investment of Harvest's assets, the calculation and payment of cash distributions to Unitholders, the calling of and conduct of business at meetings of Unitholders, the appointment and removal of the Trustee and the redemption of Trust Units. Among other things, material amendments to the Trust

Indenture, the early termination of Harvest and the sale or transfer of all or substantially all of the property of Harvest require the approval of a Special Resolution by 66 2/3% of the votes cast at a Special Meeting of the Unitholders. The Trust Indenture has been amended and restated on each of July 10, 2003, May 4, 2005, February 3, 2006, January 1, 2008 and May 20, 2008.

The Trust has also issued six series of unsecured subordinated convertible debentures and has assumed two series of unsecured subordinated convertible debentures upon the completion of the acquisition of Viking on February 3, 2006 (of which one series of Debentures matured in 2008 and was settled with the issuance of Trust Units). The Debentures are governed by the terms of the Debenture Indenture. These Debentures are convertible into fully paid and non-assessable Trust Units, at the option of the holder, at any time prior to the close of business on the earlier of the maturity date and the business day immediately preceding the date specified by the Trust for redemption. The conversion price per Trust Units is specified for each series.

The Trust Indenture allows for the creation of an unlimited number of Special Voting Units to enable the Trust to effect exchangeable securities transactions. Exchangeable securities transactions are commonly used in corporate acquisitions to give the selling securityholder a tax deferred "rollover" on the sale of the securityholder's securities, which may not otherwise be available. In an exchangeable securities transaction the tax event is generally deferred until the exchangeable securities are actually exchanged. Holders of Special Voting Units are not entitled to any distributions of any nature whatsoever from the Trust, but are entitled to such number of votes at meetings of Unitholders as may be prescribed by Harvest's Board in the resolution authorizing the issuance of any Special Voting Units. Except for the right to vote at meetings of the Unitholders, the Special Voting Units shall not confer upon the holders thereof any other rights. As of December 31, 2008, no Special Voting Units were outstanding.

Trust Units and the Trust Indenture

Effective upon the amendment and restatement of the Trust Indenture which occurred concurrent with the closing of the Viking Arrangement on February 3, 2006, the Trust is authorized to issue three classes of Trust Units, described and designated as Ordinary Trust Units, Special Trust Units and Special Voting Units, pursuant to the amended and restated Trust Indenture. Each Ordinary Trust Unit entitles the holder or holders thereof to one vote at any meeting of the Unitholders and each Special Trust Unit shall entitle the holder or holders thereof to three-sixteenths of one vote at any meeting of the Unitholders. The Special Trust Units were created and issued to enable the closing of the Viking Arrangement and all have been subsequently cancelled. Unless otherwise specifically designated as such, all references to Trust Units are deemed to be references to Ordinary Trust Units.

As of March 24, 2009, there were 161,505,296 Trust Units (157,200,701 Trust Units at December 31, 2008) issued and outstanding. Each Trust Unit entitles the holder thereof to one vote at any meeting of the holders of Trust Units and represents an equal undivided beneficial interest in any distribution from the Trust (whether of net income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding-up of the Trust. All Trust Units shall rank among themselves equally and rateably without discrimination, preference or priority. Each Trust Unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require the Trust to redeem any or all of the Trust Units held by such holder (see "Redemption Right" below). See "Risk Factors – Risks Related to Harvest's Structure Nature of Trust Units".

The Trust Indenture also provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Harvest Board may determine. The Trust Indenture also provides that Harvest Operations may authorize the creation and issuance of debentures, notes and other evidences of indebtedness of the Trust from time to time on such terms and conditions to such persons and for such consideration as Harvest Operations may determine.

The following is a summary of certain provisions of the Trust Indenture and the Trust Units. For a complete description, reference should be made to the Trust Indenture, as may be subsequently amended and superseded, a copy of which may be viewed at the offices of, or obtained from, the Trustee and a copy of which has been filed on SEDAR at www.sedar.com.

Unitholder Limited Liability

The Trust Indenture provides that no Unitholder, in its capacity as such, shall incur or be subject to any liability in contract or in tort in connection with the Trust Fund or the obligations or affairs of the Trust or with respect to any act or omission of the Trustee or any other person in the performance or exercise, or purported performance or exercise, of any obligation, power, discretion or authority conferred upon the Trustee or such other person hereunder or with respect to any transaction entered into by the Trustee or by any other person pursuant to the Trust Indenture. No Unitholder shall be liable to indemnify the Trustee or any such other person with respect to any such liability or liabilities incurred by the Trustee or by any such other person or persons or with respect to any taxes payable by the Trust or by the Trustee or by any other person on behalf of or in connection with the Trust. See “Risk Factors – Risks Related to Harvest’s Structure – Nature of Trust Units and Unitholder Unlimited Liability.”

Redemption Right

Trust Units are redeemable at any time on demand by the holders thereof upon delivery to the Trust of the certificate or certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requiring redemption. Upon receipt of the notice to redeem Trust Units by the Trust, the holder thereof shall only be entitled to receive a price per Trust Unit (the "**Market Redemption Price**") equal to the lesser of: (i) 90% of the "market price" (as defined in the Trust Indenture) of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units are tendered to the Trust for redemption; and (ii) the closing market price on the principal market on which the Trust Units are quoted for trading on the date that the Trust Units are so tendered for redemption.

The Trust Indenture imposes limitations on the amount of cash consideration the Trust may pay out for the Trust Units tendered for redemption and also provides for the determination of the value of the Market Redemption Price payable if the Trust Units are not listed for trading on the TSX or any other stock exchange. The details of these provisions can be reviewed in further detail in the Trust Indenture filed on SEDAR at www.sedar.com.

It is anticipated that this Redemption Right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Promissory notes of Harvest Operations or the Trust which may be distributed in specie to Unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in such notes. Such notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

Non-Resident Ownership

The Trust Indenture provides that it is intended that the Trust qualify as a "unit trust" and a "mutual fund trust" under the Tax Act. For the Trust to qualify as a "mutual fund trust" for the purposes of the Tax Act, it is required that, among other things, (i) the Trust not be considered to be a trust established or maintained primarily for the benefit of non-residents of Canada; or (ii) the Trust satisfies certain conditions as to the nature of the assets of the Trust as specified in the Tax Act (the "**Asset Test**"). Harvest believes that the Trust has at all material times satisfied the Asset Test and accordingly, for purposes of the Tax Act, the Trust should qualify as a "mutual fund trust".

In addition, Harvest, with the assistance of its transfer agent and registrar for the Trust Units, Valiant Trust Company, maintains a process of soliciting participant declaration forms from all registered holders of its Trust Units. The participation declaration forms requires the certification of the number of Trust Units held by non-residents of Canada and the number of non-residents holders, all as defined by the Tax Act. This process includes the solicitation of such forms by the Canadian Depository for Securities and, indirectly, the Depository Trust company. At the end of each quarter, Harvest instructs Valiant Trust Company to complete this solicitation process and report the results. As at December 31, 2008, the non-resident holders of Trust Units represented approximately 71% of the Trust's issued and outstanding Trust Units.

Trustee

Valiant Trust Company is the trustee of the Trust. All of the administrative and management powers of the Trustee relating to the Trust and the operations of the Trust have been delegated to Harvest Operations pursuant to the Trust Indenture and the Administration Agreement. Notwithstanding this general delegation, pursuant to the Administration Agreement, the Trustee has agreed not to delegate any authority to manage the following affairs of the Trust:

(a) the issue, certification, countersigning, transfer, exchange and cancellation of certificates representing Trust Units;

(b) the maintenance of a register of Unitholders;

(c) the cash distributions paid to Unitholders, although the calculation of the amount of the distribution shall be made by Harvest Operations and approved by the Harvest Board;

(d) the mailing of notices, financial statements and reports to Unitholders pursuant to the Trust Indenture, although Harvest Operations shall be responsible for the preparation or causing the preparation of such notices, financial statements and reports;

(e) the provision of a basic list of registered Unitholders to Unitholders in accordance with the procedures outlined in the Trust Indenture;

(f) the amendment or waiver of the performance or breach of any term or provision of the Trust Indenture on behalf of the Trust;

(g) the renewal or termination of the Administration Agreement on behalf of the Trust; and

(h) any matter which requires the approval of the Unitholders under the terms of the Trust Indenture.

The Trustee is required under the Trust Indenture to exercise its powers and carry out its functions thereunder as Trustee honestly, in good faith and in the best interests of the Trust and the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

The Unitholders shall reappoint the Trustee or appoint a successor to the Trustee at each annual meeting of Unitholders. The Trustee may also be removed by Harvest Operations upon delivery of a notice in writing from Harvest Operations to the Trustee in limited circumstances. Such resignation or removal becomes effective only upon the approval of the Unitholders by Special Resolution, the acceptance or appointment of a successor trustee and the assumption by the successor trustee of all obligations of the Trustee and in the same capacity.

Liability of the Trustee

The Trustee, its directors, officers, employees, shareholders and agents shall not be liable to any Unitholder or any other person, in tort, contract or otherwise, in connection with any matter pertaining to the Trust or the Trust Fund, arising from the exercise by the Trustee of any powers, authorities or discretion conferred under the Trust Indenture, including, without limitation, any action taken or not taken in good faith in reliance on any documents that are, *prima facie*, properly executed, any depreciation of, or loss to, the Trust Fund incurred by reason of the sale of any asset, any inaccuracy in any valuation provided by any other appropriately qualified person, any reliance on any such evaluation, any action or failure to act of Harvest Operations, or any other person to whom the Trustee has, with the consent of Harvest Operations, delegated any of its duties under the Trust Indenture, or any other action or failure to act (including failure to compel in any way any former trustee to redress any breach of trust or any failure by Harvest Operations to perform its duties under or delegated to it under the Trust Indenture or any other contract), unless such liabilities arise out of the gross negligence, wilful default or fraud of the Trustee or any of its directors, officers, employees or shareholders. If the Trustee has retained an appropriate expert, adviser or legal counsel with respect to any matter connected with its duties under the Trust Indenture or any other contract, the Trustee may act or refuse to act based on the advice of such expert, adviser or legal counsel, and the Trustee shall not be liable for and shall be fully protected from any loss or liability occasioned by any action or refusal to act based on the advice of any such expert, adviser or legal counsel. In the exercise of the powers, authorities or discretion conferred upon the Trustee under the Trust Indenture, the Trustee is and shall be conclusively deemed to be acting as Trustee of the assets of the Trust and shall not be subject to any personal liability for any debts, liabilities, obligations, claims, demands, judgments, costs, charges or expenses against or with respect to the Trust or the Trust Fund. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Delegation of Authority, Administration and Governance

Harvest Operations (and, accordingly, the Harvest Board) has generally been delegated the significant management decisions of the Trust. In particular, the Trustee has delegated to Harvest Operations responsibility for any and all matters relating to the following: (i) an offering of securities; (ii) ensuring compliance with all applicable laws, including in relation to an offering; (iii) all matters relating to the content of any offering documents, the accuracy of the disclosure contained therein, and the certification thereof; (iv) all matters concerning the terms of, and amendment from time to time of the material contracts of the Trust; (v) all matters concerning any underwriting or agency agreement providing for the sale of Trust Units or rights to Trust Units; (vi) all matters relating to the redemption of Trust Units; (vii) all matters relating to the voting rights on any investments in the Trust Fund or any Subsequent Investments; (viii) all matters relating to the specific powers and authorities as set forth in the Trust Indenture.

Harvest Operations currently has a board of directors consisting of 9 individuals, and will present a slate of 8 directors to the Unitholders at its Annual and Special Meeting to be held on May 19, 2009. David J. Boone will not be standing for re-election to the Board in 2009. Pursuant to the Trust Indenture, Unitholders are entitled to elect the Board of Directors annually. Prior to all annual meetings, Harvest Operations will deliver an information circular and form of proxy to Unitholders with respect to the election of the directors of Harvest Operations at any such meeting.

Under the NPI Agreements, the Operating Subsidiaries have the exclusive control and authority over development of, and recovery of petroleum, natural gas and natural gas liquids from, the Properties and lands pooled or unitized therewith, including, without limitation, making all decisions respecting whether, when and how to drill, complete, equip, produce, suspend, abandon and shut-in wells and whether to elect to convert royalties to working interests. The Harvest Board has determined that all significant operational decisions and all decisions relating to: (i) the acquisition and disposition of assets for a purchase price or proceeds in excess of $5 million; (ii) the approval of capital expenditure budgets; (iii) the approval of risk management policies and activities proposed to be undertaken, and (iv) the establishment of credit facilities, shall be made by the Harvest Board.

In exercising its powers and discharging its duties, Harvest Operations must act honestly and in good faith and exercise the degree of care, diligence and skill that a reasonably prudent oil and natural gas industry advisor and administrator would exercise in comparable circumstances. Harvest Operations' objective in exercising its powers and discharging its duties is to maximize the income distributable to the Unitholders to the extent consistent with long-term growth in the value of the Trust. In pursuing such an objective, Harvest Operations employs and will continue to employ prudent oil and natural gas business practices. All of Harvest Operations' business is and will continue to be conducted in accordance with applicable laws with a view to the best interests of the Unitholders and the Trust.

The Harvest Board reviews on an ongoing basis both the nature and extent of the services required of Harvest Operations by the Trust and the costs of providing such services.

General and administrative costs are deducted from production revenues in computing income from the Net Profits Interest to the extent not paid from the residual income of Harvest Operations or deducted by the Trust in determining cash available for distribution to Unitholders. General and administrative costs are generally charged to the Trust by Harvest Operations based on direct costs incurred in fulfilling the obligations of Harvest Operations to the Trust pursuant to the Trust Indenture and the Administration Agreement. Harvest Operations is entitled to reimbursement for all of its direct and indirect expenses, costs and expenditures in connection with the creation, start-up, set-up and organization of the Trust.

Meetings of Unitholders

The Trust Indenture provides that meetings of Unitholders must be called and held for, among other matters, the election or removal of the Trustee, the appointment or removal of the auditors of the Trust, the approval of amendments to the Trust Indenture, the sale of the property of the Trust as an entirety or substantially as an entirety, and the commencement of winding-up the affairs of the Trust. Meetings of Unitholders will be called and held annually for, among other things, the election of the directors of Harvest Operations and the appointment of the auditors of the Trust.

A meeting of Unitholders may be convened at any time and for any purpose by Harvest Operations and must be convened, except in certain circumstances, if requisitioned by the holders of not less than 20% of the Trust Units then outstanding by a written requisition. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called.

Unitholders may attend and vote at all meetings of Unitholders either in person or by proxy and a proxyholder need not be a Unitholder. Two persons present in person or represented by proxy and representing in the aggregate at least 10% of the votes attaching to all outstanding Trust Units shall constitute a quorum for the transaction of business at all such meetings.

The Trust Indenture contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of Unitholders in accordance with the requirements of applicable laws.

Take-Over Bid

The Trust Indenture contains provisions to the effect that if a take-over bid is made for the Trust Units and not less than 90% of the Trust Units (other than Trust Units held at the date of the takeover bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Trust Units held by Unitholders who did not accept the takeover bid on the terms offered.

Termination of the Trust

Unitholders may vote to terminate the Trust at any meeting of the Unitholders duly called for that purpose, subject to the following: (a) a vote may only be held if requested in writing by the holders of not less than 20% of the outstanding Trust Units; (b) a quorum of 50% of the issued and outstanding Trust Units is present in person or by proxy; and (c) the termination must be approved by Special Resolution of Unitholders.

Unless the Trust is earlier terminated or extended by vote of the Unitholders, the Trustee shall commence to wind-up the affairs of the Trust on December 31, 2099. In the event that the Trust is wound-up, the Trustee will sell and convert into cash the Direct Royalties and other assets comprising the Trust Fund in one transaction or in a series of transactions at public or private sale and do all other acts appropriate to liquidate the Trust Fund, and shall in all respects act in accordance with the directions, if any, of the Unitholders in respect of termination authorized pursuant to the Special Resolution authorizing the termination of the Trust. However, in no event shall the Trust be wound-up until the Direct Royalties have been disposed of. After paying, retiring or discharging, or making provision for the payment, retirement, or discharge of all known liabilities and obligations of the Trust including the full repayment of the principal of and interest on the Debentures of the Trust and after providing for indemnity against any other outstanding liabilities and obligations, the Trustee shall distribute the remaining part of the proceeds of the sale of the assets together with any cash forming part of the property of the Trust among the Unitholders in accordance with their Pro Rata Share**.**

Reporting to Unitholders

The consolidated financial statements of the Trust will be audited annually by an independent recognized firm of chartered accountants. The audited consolidated financial statements of the Trust, together with the report of such chartered accountants, will be mailed by the Trust to registered Unitholders and the unaudited interim consolidated financial statements of the Trust will be mailed to registered Unitholders within the periods prescribed by securities legislation. The year end of the Trust is December 31. The Trust is subject to the continuous disclosure obligations under the applicable securities legislation of each of the provinces and certain of the territories of Canada.

Borrowing By the Trust

Pursuant to the Trust Indenture, the Trustee is permitted to, directly or indirectly, borrow money from or incur indebtedness to any person and in connection therewith, to guarantee, indemnify or act as a surety with respect to payment or performance of any indebtedness, liabilities or obligation of any kind of any person, including, without limitation, Harvest Operations and any other subsidiary of the Trust; to enter into any other obligations on behalf of the Trust; or enter into any subordination agreement on behalf of the Trust or any other person, and to assign, charge, pledge, hypothecate, convey, transfer, mortgage, subordinate, and grant any security interest, mortgage or encumbrance over or with respect to all or any of the Trust Fund or to subordinate the interests of the Trust in the Trust Fund to any other person. Debt service costs incurred by the Trust are deducted in determining the cash available for distribution to Unitholders.

Premium Distribution™, Distribution Reinvestment and Optional Trust Units Purchase Plan ("DRIP Plan")

The Trust has adopted the DRIP Plan which provides holders of Trust Units the means of accumulating additional Trust Units by reinvesting cash distributions. At the discretion of Harvest Operations, Trust Units will be issued from treasury at 95% of the market price of the Trust Units (calculated as the weighted average trading price of the Trust Units on the TSX on which at least a board lot of Trust Units is traded for the period commencing on the second Business Day following the record date applicable to such distribution payment, and ending on the second Business Day immediately prior to the distribution payment date). Unitholders who are residents of the United States are eligible to elect to reinvest distributions to purchase additional Trust Units pursuant to the DRIP Plan.

Effective August 23, 2005, the DRIP Plan includes a unique feature which allows eligible Unitholders to elect, under the Premium Distribution™ component of the DRIP Plan, to deliver Trust Units which have been received pursuant to the distribution reinvestment component of the DRIP Plan to a designated broker in exchange for a premium cash distribution equal to 102% of the cash distribution that such Unitholders would have otherwise been entitled to receive on the applicable distribution date (subject to a proration in certain events under the DRIP Plan). Canaccord Capital Corporation has been designated as the plan broker under the Premium Distribution™ component of the DRIP Plan. This component of the DRIP Plan is not available to residents of the United States.

Participants in the DRIP Plan (other than residents of the United States) are also permitted to purchase additional Trust Units at 100% of the market price (as described above) of the Trust Units by investing additional sums to a maximum of up to $100,000 aggregate amount of remittances by a Unitholder in any calendar month and a minimum of $5,000 per remittance; provided that the total number of Trust Units that may be issued each fiscal year pursuant to optional cash payments is restricted to not more than 2% of the number of issued and outstanding Trust units at the commencement of that year.

As at March 24, 2009, 27,574,614 Trust Units have been issued from treasury since February 15, 2003 as a result of Unitholder participation in the DRIP Plan with proceeds of approximately $584.1 million.

Stability Ratings

As of March 24, 2009, there are no stability ratings maintained for the Trust Units.

Debentures and the Debenture Indenture

The following is a summary of the material attributes and characteristics of the Debentures. This summary does not, however, include a description of all of the terms of each series of Debentures, and reference should be made to the respective Debenture Indenture filed at www.sedar.com for a complete description of such terms.

General

The Debentures are issued under the Debenture Indenture. The Trust may, however, from time to time, without the consent of the holders of the Debentures but subject to the limitations described herein, issue additional debentures of the same series or of a different series under the Debenture Indenture. The Debentures are issuable only in denominations of $1,000 and integral multiples thereof.

Each series of Debentures will specify a maturity date, an interest rate, the terms of the conversion privilege and the redemption terms, if any. The principal amount of the Debentures will be payable in lawful money of Canada or, at the option of the Trust and subject to applicable regulatory approval, settled with the issuance of Trust Units as further described under "- Payment upon Redemption or Maturity" and "- Redemption and Purchase". The interest on the Debentures will be payable in lawful money of Canada.

The Debentures are direct obligations of the Trust and are not be secured by any mortgage, pledge, hypothec or other charge and will be subordinated to other liabilities of the Trust as described under "Subordination". The Debenture Indenture will not restrict the Trust from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its properties to secure any indebtedness.

Conversion Privilege

Each Debenture is convertible at the holder's option into fully paid and non-assessable Trust Units at any time prior the earlier of the Final Maturity Date and the Business Day immediately preceding the date specified by the Trust for redemption of the Debentures at a specified conversion price. No adjustment will be made for distributions on Trust Units issuable upon conversion or for interest accrued on Debentures surrendered for conversion; however, holders converting their Debentures will receive accrued and unpaid interest thereon.

Subject to the provisions thereof, the Debenture Indenture will provide for the adjustment of the specified conversion price in certain events including: (a) the subdivision, redivision or consolidation, reduction or combination of the outstanding Trust Units; (b) the distribution of Trust Units to holders of Trust Units by way of distribution or otherwise other than an issue of securities to holders of Trust Units who have elected to receive distributions in securities of the Trust in lieu of receiving cash distributions paid in the ordinary course; (c) the issuance of options, rights or warrants to holders of Trust Units entitling them to acquire Trust Units or other securities convertible into Trust Units at less than 95% of the then current market price (as defined below under "**Payment upon Redemption or Maturity**") of the Trust Units; and (d) the distribution to all holders of Trust Units of any securities or assets (other than cash distributions and equivalent distributions in securities paid in lieu of cash distributions in the ordinary course). There will be no adjustment of the specified conversion price in respect of any event described in (b), (c) or (d) above if the holders of the Debentures are allowed to participate as though they had converted their Debentures prior to the applicable record date or effective date. The Trust will not be required to make adjustments in the specified conversion price unless the cumulative effect of such adjustments would change the conversion price by at least 1%.

In the case of any reclassification or capital reorganization (other than a change resulting from consolidation or subdivision) of the Trust Units or in the case of any consolidation, amalgamation, arrangement or merger of the Trust with or into any other entity, or in the case of any sale or conveyance of the properties and assets of the Trust as, or substantially as, an entirety to any other entity, or a liquidation, dissolution or winding-up of the Trust, the terms of the conversion privilege shall be adjusted so that each holder of an unsecured subordinated convertible debenture shall, after such reclassification, capital reorganization, consolidation, amalgamation, merger, sale, conveyance, liquidation, dissolution or winding up, be entitled to receive the number of Trust Units or other securities or property such holder would be entitled to receive if on the effective date thereof, it had been the registered holder of the number of Trust Units into which the Debenture was convertible prior to the effective date of such reclassification, capital reorganization, consolidation, amalgamation, merger, sale, conveyance, liquidation, dissolution or winding up.

No fractional Trust Units will be issued on any conversion but in lieu thereof the Trust shall satisfy fractional interests by a cash payment equal to the current market price of any fractional interest.

Redemption and Purchase

The Debentures may be redeemable after a specified date and prior to maturity in whole or in part from time to time at the option of the Trust on not more than 60 days and not less than 30 days prior notice as specified for each series of Debentures plus accrued and unpaid interest thereon, if any. In the case of redemption of less than all of a series of Debentures, the Debentures to be redeemed will be selected by the Debenture Trustee on a pro rata basis or in such other manner as the Debenture Trustee deems equitable, subject to the consent of the TSX. The Trust has the right to purchase the Debentures in the market, by tender or by private contract.

Payment upon Redemption or Maturity

On redemption or at maturity, the Trust will repay the indebtedness represented by the Debentures by paying to the Debenture Trustee in lawful money of Canada an amount equal to the aggregate Redemption Price of the outstanding Debentures which are to be redeemed or the principal amount of the outstanding Debentures which have matured, as the case may be, together with accrued and unpaid interest thereon. The Trust may, at its option, on not more than 60 days and not less than 40 days prior notice and subject to applicable regulatory approval, elect to satisfy its obligation to pay the Redemption Price of the Debentures which are to be redeemed or the principal amount of the Debentures which have matured, as the case may be, by issuing Trust Units to the holders of the Debentures. Any accrued and unpaid interest thereon will be paid in cash. The number of Trust Units to be issued will be determined by dividing the aggregate Redemption Price of the outstanding Debentures which are to be redeemed or the principal amount of the outstanding Debentures which have matured, as the case may be, by 95% of the current market price on the date fixed for redemption or the maturity date, as the case may be. No fractional Trust Units will be issued on redemption or maturity but in lieu thereof the Trust shall satisfy fractional interests by a cash payment equal to the current market price of any fractional interest.

The term "current market price" will be defined in the Debenture Indenture to mean the weighted average trading price of the Trust Units on the TSX for the 20 consecutive trading days ending on the fifth trading day preceding the date fixed for redemption or the maturity date, as the case may be.

Subordination

The payment of the principal of and interest on the Debentures will be subordinated in right of payment, as set forth in the Debenture Indenture, to the prior payment in full of all Senior Indebtedness of the Trust and indebtedness to trade creditors of the Trust. "Senior Indebtedness" of the Trust is defined in the Debenture Indenture as the principal of and premium, if any, and interest on and other amounts in respect of all indebtedness of the Trust or any subsidiary of the Trust (whether outstanding as at the date of the Indenture or thereafter incurred), other than indebtedness evidenced by the Debentures and all other existing and future debentures or other instruments of the Trust which, by the terms of the instrument creating or evidencing the indebtedness, is expressed to be *pari passu* with, or subordinate in right of payment to, the Debentures. The Debentures will also be effectively subordinate to claims of creditors of the Trust's subsidiaries except to the extent the Trust is a creditor of such subsidiaries ranking at least *pari passu* with such other creditors.

The Debenture Indenture will provide that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings relative to the Trust, or to its property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding-up of the Trust, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of the Trust, then those holders of Senior Indebtedness, including any indebtedness to trade creditors, will receive payment in full before the holders of Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any of the Debentures or any unpaid interest accrued thereon. The Debenture Indenture will also provide that the Trust will not make any payment, and the holders of the Debentures will not be entitled to demand, institute proceedings for the collection of, or receive any payment or benefit (including, without any limitation, by set-off, combination of accounts or realization of security or otherwise in any manner whatsoever) on account of indebtedness represented by the Debentures (a) in a manner inconsistent with the terms (as they exist on the date of issue) of the Debentures or (b) at any time when an event of default has occurred under the Senior Indebtedness and is continuing and notice of such event of default has been given by or on behalf of the holders of Senior Indebtedness to the Debenture Trustee, unless the Senior Indebtedness has been repaid in full. No holder of a Debenture has the right to institute any act or proceeding to enforce the Debentures in a manner inconsistent with the terms of the Indenture.

Priority over Trust Distributions

The Trust Indenture provides that certain expenses of the Trust must be deducted in calculating the amount to be distributed to the Unitholders. Accordingly, the funds required to satisfy the interest payable on the Debentures, as well as the amount payable upon redemption or maturity of the Debentures or upon an Event of Default (as defined below), will be deducted and withheld from the amounts that would otherwise be payable as distributions to Unitholders except for distributions that have been publicly announced by the Trust.

Debentures May Be Issued in Series and Rank Pari Passu

The Debentures may be issued in one or more series with each series established by a supplement to the Indenture specifying, among other things, any limit to the aggregate principal amount of the Debentures of the series to be issued, the date or dates on which the principal of the Debentures of the series is payable, the rate or rates at which the Debentures of the series shall bear interest, the right, if any, of the Trust to redeem Debentures of the series and the period or periods and price and whether and under what circumstances and terms, the Debentures of the series will be convertible into Trust Units.

All issued and outstanding Debentures of the Trust are direct unsecured obligations of the Trust with each series of Debentures ranking *pari passu* with all other series of Debentures of the Trust and each Debenture of a series ranking *pari passu* with each Debenture of the same series of Debentures.

Change of Control of the Trust

Within 30 days following the occurrence of a change of control of the Trust involving the acquisition of voting control or direction over 66 2/3% or more of the Trust Units (a "**Change of Control**"), the Trust will be required to make an offer in writing to purchase all of the Debentures then outstanding (the "**Debenture Offer**"), at a price equal to 101% of the principal amount thereof plus accrued and unpaid interest (the "**Debenture Offer Price**"). The Debenture Indenture provides that a change of control does not include a merger, reorganization, combination or other similar transaction if the previous holders of Trust Units and securities convertible or carrying the right to acquire Trust Units hold at least 50% of the voting control or direction in such merged, reorganized, combined or other continuing entity.

The Debenture Indenture contains notification and repurchase provisions requiring the Trust to give written notice to the Debenture Trustee of the occurrence of a Change of Control within 30 days of such event together with the Debenture Offer. The Debenture Trustee will thereafter promptly mail to each holder of Debentures a notice of the Change of Control together with a copy of the Debenture Offer to repurchase all the outstanding Debentures.

If 90% or more of the aggregate principal amount of the Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered to the Trust pursuant to the Debenture Offer, the Trust will have the right and obligation to redeem all the remaining Debentures at the Debenture Offer Price. Notice of such redemption must be given by the Trust to the Debenture Trustee within 10 days following the expiry of the Debenture Offer, and as soon as possible thereafter, by the Debenture Trustee to the holders of the Debentures not tendered pursuant to the Debenture Offer.

Restrictions on Certain Transactions

The Debenture Indenture contains provisions to the effect that subject to the discussion under "Offers for Debentures" below, the Trust shall not enter into any transaction or series of transactions whereby all or substantially all of its undertaking, property or assets would become the property of any other person (herein called a "**Successor**") whether by way of reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise, unless, among other things prior to or contemporaneously with the consummation of such transaction the Trust and the Successor shall have executed such instruments and done such things as are necessary or advisable to establish that upon the consummation of such transaction the Successor will have assumed all the covenants and obligations of the Trust under the Debenture Indenture in respect of the Debentures and the Debentures will be valid and binding obligations of the Successor entitling the holders thereof, as against the Successor, to all the rights of Debenture holders under the Debenture Indenture.

Events of Default

The Debenture Indenture provides that an event of default ("**Event of Default**") in respect of the Debentures will occur if any one or more of the following described events has occurred and is continuing with respect of the Debentures: (a) failure for 10 days to pay interest on the Debentures when due; (b) failure to pay principal or premium, if any, on the Debentures when due, whether at maturity, upon redemption, by declaration or otherwise; (c) certain events of bankruptcy, insolvency or reorganization of the Trust under bankruptcy or insolvency laws; or (d) default in the observance or performance of any material covenant or condition of the Indenture and continuance of such default for a period of 30 days after notice in writing has been given by the Debenture Trustee to the Trust specifying such default and requiring the Trust to rectify the same. If an Event of Default has occurred and is continuing, the Debenture Trustee may, in its discretion, and shall upon receipt of a written request signed by holders of not less than 25% of the principal amount of Debentures then outstanding, declare the principal of and interest on all outstanding Debentures to be immediately due and payable. In certain cases, the holders of more than 50% of the principal amount of the Debentures then outstanding may, on behalf of the holders of all Debentures, by written request, instruct the Debenture Trustee to waive any Event of Default and/or cancel any such declaration upon such terms and conditions as such holders shall prescribe.

Covenants of the Trust

The Debenture Indenture includes covenants of the Trust with the Debenture Trustee to, among other things, pay principal, premium (if any) and interest to the holders of the Debentures on the date specified in the Debenture Indenture and respective supplemental indentures and to limit distributions to the holders of the Trust Units if at the time the directors of the Harvest Board resolve to make the said declaration, the directors of the Harvest Board has actual knowledge that the paying of said distribution on the payment date will result in an Event of Default.

Offers for Debentures

The Debenture Indenture contains provisions to the effect that if an offer is made for the Debentures which is a take-over bid for Debentures within the meaning of the *Securities Act* (Alberta) and not less than 90% of the Debentures (other than Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Debentures held by the holders of Debentures who did not accept the offer on the terms offered by the offeror.

Modification

The rights of the holders of the Debentures issued under the Debenture Indenture may be modified in accordance with the terms of the Debenture Indenture. For that purpose, among others, the Debenture Indenture will contain certain provisions which will make binding on all Debenture holders resolutions passed at meetings of the holders of Debentures by votes cast thereat by holders of not less than 66 2/3% of the principal amount of the Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66 2/3% of the principal amount of the Debentures then outstanding. In certain cases, the modification will, instead or in addition, require assent by the holders of the required percentage of Debentures of each particularly affected series.

Limitation on Issuance of Additional Debentures

The Debenture Indenture provides that the Trust shall not issue additional unsecured subordinated convertible debentures of equal ranking if the principal amount of all issued and outstanding convertible debentures of the Trust exceeds 25% of the Total Market Capitalization of the Trust immediately after the issuance of such additional convertible debentures. "Total Market Capitalization" will be defined in the Debenture Indenture as the total principal amount of all issued and outstanding debentures of the Trust which are convertible at the option of the holder into Trust Units of the Trust plus the amount obtained by multiplying the number of issued and outstanding Trust Units of the Trust and any outstanding exchangeable equity interests of the Trust (other than subordinated convertible debt) by the current market price of the Trust Units on the relevant date.

Normal Course Issuer Bid

Management of Harvest believes that, from time to time, the market price of its Trust Units and/or Debentures may not fully reflect their underlying value and that at such times the purchase of Trust Units and/or Debentures may be in the best interests of Harvest. Such purchases will increase the proportionate interest of, and may be advantageous to, all remaining holders of the Trust Units and Debentures. In addition, the purchases by Harvest may increase liquidity of the Trust Units and Debentures. Accordingly, on October 20, 2008, the Toronto Stock Exchange accepted Harvest's Notice of Intention to commence a Normal Course Issuer Bid (the "Bid") to purchase for cancellation up to a maximum of:

- 14,826,261 Trust Units,
- $94,000 aggregate principal amount of 9% Debentures Due 2009,
- $158,000 aggregate principal amount of 8% Debentures Due 2009,
- $3,706,000 aggregate principal amount of 6.5% Debentures Due 2010,
- $17,332,000 aggregate principal amount of 6.40% Debentures Due 2012,
- $37,844,000 aggregate principal amount of 7.25% Debentures Due 2013,
- $7,270,000 aggregate principal amount of 7.25% Debentures Due 2014, and
- $24,963,000 aggregate principal amount of 7.5% Debentures Due 2015.

The maximum number of Trust Units and Debentures approved for purchased pursuant to the Bid represents 10% of the issued and outstanding Trust Units and Debentures which were not held by insiders of the Trust on October 20, 2008. The Bid commenced on October 23, 2008 and will terminate on October 22, 2009 or such earlier time as the Bid is completed or terminated at the option of Harvest.

Purchases are to be made on the open market through the facilities of the TSX at the prevailing market price at the time of such purchase. The actual number of Trust Units and Debentures that may be purchased for cancellation and the timing of any such purchases will be determined by Harvest, subject to the following maximum daily purchase limits:

- 132,622 Trust Units,
- $1,000 aggregate principal amount of 9% Debentures Due 2009
- $1,000 aggregate principal amount of 8% Debentures Due 2009,
- $7,000 aggregate principal amount of 6.5% Debentures Due 2010,
- $20,000 aggregate principal amount of 6.40% Debentures Due 2012,
- $169,000 aggregate principal amount of 7.25% Debentures Due 2013,
- $44,000 aggregate principal amount of 7.25% Debentures Due 2014, and
- $196,000 aggregate principal amount of 7.5% Debentures Due 2015.

To date, we have not purchased any securities pursuant to this Normal Course Issuer Bid.

SUPPLEMENTAL CAPITAL STRUCTURE INFORMATION

The Trust Indenture provides that Harvest Operations may authorize the creation and issuance of debentures, notes and other evidence of indebtedness of the Trust and its subsidiaries from time to time on such terms and conditions to such persons and for such consideration as the Board of Directors of Harvest Operations may approve. As at December 31, 2008, Harvest Operations had a $1.6 billion Extendible Revolving Credit Facility ("**Secured Debt**") and US$250 million of $7^{7/8}$% Senior Notes (collectively, the "**Senior Debt**"). The Senior Debt are legal obligations of Harvest Operations and are guaranteed by the Trust and its subsidiaries. Payments on the Senior Debt have priority over payments to the Trust pursuant to the NPI Agreements, interest and principal payments on unsecured debt owing to the Trust as well as the distributions from the Trust's wholly-owned partnerships and trusts. Accordingly, in the event of a default or a failure to re-finance, distributions from the Trust to Unitholders may be reduced or suspended. However, Unitholders have no direct liability with respect to the Senior Debt.

A copy of the Extendible Revolving Credit Facility agreement (including amendments thereto) and $7^{7/8}$% Senior Note Indenture are filed as Material Contracts on SEDAR at www.sedar.com.

Extendible Revolving Credit Facility

This $1.6 billion Extendible Revolving Credit Facility is a secured covenant-based credit facility with a syndicate of financial institutions that is currently scheduled to mature in April 2010, subject to further extension by the lenders. Harvest has provided the lenders with a $2.5 billion first floating charge over all of its assets plus a first mortgage security interest on the refinery assets. As at December 31, 2008, $1,226.2 million was drawn on this facility. This credit facility requires standby fees on un-drawn amounts and interest on amounts borrowed at varying rates depending on Harvest's ratio of the drawn amount of under Extendible Revolving Credit Facility to its earnings before interest, taxes, depletion, amortization over the previous four quarters ("EBITDA") as more fully defined below.

In addition to the standard representations, warrants and covenants commonly contained in a credit facility, Harvest's Extendible Revolving 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 Unitholders in certain circumstances such as an event of default, and

(d) A limitation on the availability of borrowing pursuant to the Borrowing Base Covenant of the $7^{7/8}$% Senior Notes described below and also subject to the following quarterly financial covenants:

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

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

   (3) Drawn amount of Secured Debt to Capitalization 50% or less

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

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

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

Interest and financing charges,

Future income tax expense,

Depletion, depreciation, amortization and other,

Unrealized gains/losses on risk management contracts,

Unrealized currency exchange gains/losses, and

Non-cash unit based compensation expense

(f) Capitalization is the aggregate of the amounts drawn under the Extendible Revolving Credit Facility, the $7^{7/8}$% Senior Notes, the Debentures and the Unitholders' Equity, all as reported in Harvest consolidated balance sheet in accordance with Canadian generally accepted accounting principles.

With respect to these financial covenants, Harvest's December 31, 2008 financial ratios were as follows:

- Drawn amount of Secured Debt to EBITDA of 1.5 to 1.0
- Total amount of Senior Debt to EBITDA of 1.8 to 1.0
- Drawn amount of Secured Debt to Capitalization 25%
- Total amount of Senior Debt to Capitalization 31%

$7^{7/8}$% Senior Notes

On October 15, 2004, Harvest issued US$250 million of $7^{7/8}$% Senior Notes which mature on October 15, 2011 and contain the following financial covenants in addition to the standard representations, warrants and covenants:

(a) A limitation on additional indebtedness if such incurrence would result in an interest coverage ratio of less than 2.5 to 1.0,

(b) A limitation on additional secured debt if such incurrence would result in secured debt exceeding 65% of the present value of the future net revenues from its proved petroleum and natural gas reserves discounted at an annual rate of 10% (the "Borrowing Base"), and

(c) A limitation on the payment of distributions to Unitholders to an aggregate amount not to exceed an amount equal to $40 million plus 100% of the net cash proceeds from the issuance of Trust Units plus 80% of cash from operating activities before the settlement of asset retirement obligations and changes in non-cash working capital since the issuance of the $7^{7/8}$% Senior Notes.

With respect to these financial covenants, Harvest's December 31, 2008 financial covenant test were as follows:

- The interest coverage ratio was 6.1 times
- Total borrowing base was approximately $1.9 billion
- The aggregate of $40 million plus 100% of net cash proceeds from the issuance of Trust Units and 80% of cash from operating activities before the settlement of asset retirement obligations and changes in non-cash working capital totalled approximately $1.5 billion in excess of the distributions paid since the issuance of the $7^{7/8}$% Senior Notes.

Additional information on Harvest's Senior Debt is contained in Notes 10 and 11 to our audited consolidated financial statements for the year ended December 31, 2008 and in the "Liquidity and Capital Resources" discussion in our Management's Discussion and Analysis for the year ended December 31, 2008 both of which are filed on SEDAR at www.sedar.com.

MARKET FOR SECURITIES

The Trust Units are listed and traded on the TSX and the New York Stock Exchange ("**NYSE**"). The trading symbol on the TSX for the Trust Units is "HTE.UN", and on the NYSE is "HTE". The Trust has issued six series of unsecured subordinated convertible debentures which trade on the TSX under the symbols "HTE.DB" for the 9% Debentures Due 2009, "HTE.DB.A" for the 8% Debentures Due 2009, "HTE.DB.B" for the 6.5% Debentures Due 2010, "HTE.DB.E" for the 7.25% Debentures Due 2013, "HTE.DB.F" for the 7.25% Debentures Due 2014 and "HTE.DB.G" for the 7.50% Debentures Due 2015. In addition, pursuant to the Viking Arrangement, the Trust assumed the two outstanding series of convertible debentures that Viking had outstanding as of February 3, 2006. One of these two series, the 10.5% Debentures Due 2008 ("HTE.DB.C" and prior to the Viking Arrangement, "VKR.DB") matured on January 31, 2008 and the $24.3 million principal amount was settled on maturity with the issuance of 1,166,593 Trust Units. The other series assumed, the 6.40% Debentures Due 2012, continue to trade on the TSX under the symbol "HTE.DB.D".

The following sets forth the price range and consolidated trading volume of the Trust Units on the TSX and the NYSE for the periods indicated.

	TSX Price Range			NYSE Price Range		
	High	Low	Volume	High	Low	Volume
2008						
January	$23.56	$20.48	10,474,631	$23.24	$20.00	18,167,009
February	$26.00	$22.49	8,552,342	$25.70	$22.51	15,108,961
March	$24.13	$22.00	9,638,750	$24.49	$21.44	17,099,323
April	$24.94	$22.23	11,965,637	$24.82	$22.06	20,845,245
May	$25.67	$22.15	14,019,461	$26.08	$21.75	24,871,749
June	$25.77	$23.32	9,263,955	$25.28	$23.05	16,892,369
July	$24.60	$19.32	10,210,064	$24.30	$18.80	23,625,423
August	$21.75	$18.90	12,078,183	$20.55	$17.73	17,597,112
September	$21.12	$15.89	9,834,707	$20.01	$15.17	24,126,064
October	$17.69	$ 8.33	26,521,040	$16.69	$ 7.00	65,647,621
November	$14.09	$10.65	14,381,812	$11.55	$ 8.60	37,694,288
December	$12.68	$ 9.42	11,179,958	$10.17	$ 7.26	31,705,600
2009						
January	$11.91	$10.36	10,266,136	$10.10	$ 8.25	25,461,464
February	$10.57	$ 5.87	13,739,710	$ 8.55	$ 4.69	36,881,966
March (1-24)	$ 6.20	$ 3.87	13,917,303	$ 4.83	$ 3.00	32,423,870

The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the 9% Debentures Due 2009 as reported by the TSX for the periods indicated.

2008	High	Low	Close	Volume
January	No Trades	No Trades	No Trades	-
February	$172.00	$172.00	$172.00	100
March	No Trades	No Trades	No Trades	-
April	No Trades	No Trades	No Trades	-
May	No Trades	No Trades	No Trades	-
June	No Trades	No Trades	No Trades	-
July	No Trades	No Trades	No Trades	-
August	No Trades	No Trades	No Trades	-
September	$134.48	$134.48	$134.48	100
October	$102.00	$95.50	$95.50	1,200
November	$102.99	$102.00	$102.99	1,500
December	$101.89	$99.00	$99.00	650
2009				
January	$100.99	$98.70	$99.04	4,640
February	$100.29	$97.07	$100.00	230
March (1-24)	$100.05	$98.00	$100.05	1,150

The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the 8% Debentures Due 2009 as reported by the TSX for the periods indicated.

2008	High	Low	Close	Volume
January	$139.01	$130.77	$130.77	220
February	No Trades	No Trades	No Trades	-
March	$145.00	$130.04	$145.00	1,710
April	No Trades	No Trades	No Trades	-
May	$148.00	$145.00	$148.00	220
June	$155.00	$152.50	$155.00	790
July	No Trades	No Trades	No Trades	-
August	$135.00	$130.40	$130.40	100
September	$114.59	$103.00	$109.11	650
October	$102.90	$100.28	$100.28	360
November	$100.00	$93.01	$93.01	1,070
December	No Trades	No Trades	No Trades	-
2009				
January	$99.99	$97.00	$99.99	200
February	$100.00	$99.98	$100.00	230
March (1-24)	$100.00	$100.00	$100.00	80

The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the 6.5% Debentures Due 2010 as reported by the TSX for the periods indicated.

2008	High	Low	Close	Volume
January	$99.99	$97.00	$99.50	1,370
February	$101.75	$98.00	$100.75	1,540
March	$103.80	$99.50	$99.50	3,150
April	$101.00	$95.50	$101.00	5,000
May	$100.00	$97.40	$99.50	5,660
June	$101.00	$98.75	$100.25	16,440
July	$103.50	$100.00	$100.00	3,460
August	$100.75	$98.51	$100.75	2,450
September	$100.75	$97.00	$97.00	4,110
October	$90.00	$65.51	$74.00	5,170
November	$85.00	$77.00	$79.00	6,760
December	$81.00	$67.01	$80.00	6,220
2009				
January	$89.00	$78.01	$81.00	38,790
February	$85.00	$75.00	$75.00	3,810
March (1-24)	$80.00	$68.00	$80.00	6,720

The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the 6.40% Debentures Due 2012 as reported by the TSX for the periods indicated.

2008	High	Low	Close	Volume
January	$92.50	$86.00	$92.50	16,530
February	$92.49	$89.51	$91.99	15,050
March	$92.24	$90.01	$91.99	21,460
April	$93.99	$90.00	$90.02	16,600
May	$93.50	$87.02	$92.49	22,130
June	$96.00	$91.77	$94.00	19,820
July	$95.00	$87.01	$89.99	19,560
August	$93.95	$87.01	$90.02	10,380
September	$91.99	$71.00	$73.16	17,490
October	$76.50	$50.00	$57.00	38,210
November	$64.99	$43.51	$50.94	39,480
December	$49.00	$35.00	$43.00	74,920
2009				
January	$53.99	$43.00	$44.01	24,100

February	$45.00	$38.00	$39.99	42,950
March (1-24)	$45.99	$35.00	$43.01	22,110

The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the 7.25% Debentures Due 2013 as reported by the TSX for the periods indicated.

2008	High	Low	Close	Volume
January	$93.74	$89.00	$92.50	107,160
February	$98.25	$91.56	$96.75	63,000
March	$97.00	$92.76	$93.50	136,630
April	$94.00	$91.00	$91.25	110,635
May	$92.39	$90.00	$92.10	188,475
June	$93.85	$91.81	$92.50	249,470
July	$92.75	$89.00	$90.90	99,220
August	$91.00	$89.01	$90.65	122,096
September	$90.80	$76.00	$76.50	90,860
October	$77.50	$55.00	$57.98	76,860
November	$57.50	$45.25	$51.99	112,300
December	$52.69	$37.02	$43.99	94,600
2009				
January	$52.00	$41.50	$44.99	50,290
February	$45.00	$35.00	$37.49	48,420
March (1-24)	$42.00	$32.80	$41.11	52,095

The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the 7.25% Debentures Due 2014 as reported by the TSX for the periods indicated.

2008	High	Low	Close	Volume
January	$98.00	$88.01	$94.40	53,590
February	$104.80	$95.50	$101.45	32,320
March	$101.50	$95.07	$97.00	14,720
April	$99.95	$95.00	$96.00	143,000
May	$99.99	$95.00	$98.50	33,000
June	$100.25	$98.00	$99.25	24,840
July	$98.60	$91.51	$91.51	6,060
August	$93.57	$87.50	$93.57	10,360
September	$93.01	$79.00	$80.00	12,770
October	$80.00	$57.00	$59.40	26,180
November	$64.00	$53.00	$58.00	12,090
December	$57.25	$41.20	$50.00	5,560
2009				
January	$55.00	$47.51	$47.51	4,130
February	$50.00	$38.50	$39.02	7,410
March (1-24)	$44.00	$36.00	$44.00	9,010

The 7.50% Debentures Due 2015 issued on April 25, 2008 are listed for trading on the TSX and the following table sets forth the high, low and closing trading prices and the aggregate trading volume of the 7.50% Debentures Due 2015 as reported by the TSX for the periods indicated.

2008	High	Low	Close	Volume
April	$98.50	$97.15	$97.99	4,210
May	$100.00	$93.50	$97.00	691,410
June	$99.25	$96.25	$97.40	156,450
July	$97.75	$90.50	$92.00	65,440
August	$92.50	$90.00	$91.19	39,030
September	$91.50	$75.00	$78.50	39,240
October	$77.18	$51.00	$59.99	72,450
November	$64.00	$50.00	$55.95	58,860
December	$53.50	$38.00	$43.00	81,010
2009				

January	$51.00	$43.27	$45.00	103,580
February	$46.00	$35.01	$38.55	359,610
March (1-24)	$41.52	$35.00	$41.03	46,260

DIRECTORS AND OFFICERS OF HARVEST OPERATIONS CORP.

The names, province or state and country of residence, present positions and offices with Harvest Operations and principal occupations during the past five years of the directors and executive officers of Harvest Operations at December 31, 2008 are set out in the table below.

Name and Municipality of Residence	Position with Harvest Operations	No. of Trust Units Held (1)	Principal Occupation
John A. Brussa (4) Calgary, Alberta, Canada	Director since 2002(7)	371,564	Barrister and Solicitor; Partner of Burnet, Duckworth & Palmer LLP (a law firm).
M. Bruce Chernoff (4) Calgary, Alberta, Canada	Director(7), Chairman since 2002	6,443, 926(5)	Professional Engineer; Chairman of Harvest Operations; President and Director of Caribou Capital Corp. (a private investment management company) since June 1999. Chairman and Director of Blackwatch Energy Services Corp.
Verne G. Johnson (3) Calgary, Alberta, Canada	Director since 2002(7)	9,998	Independent businessman since January 2000.
Hector J. McFadyen(2) Calgary, Alberta, Canada	Director since 2002(7)	56,997	Independent businessman and Director of Hunting PLC (a public UK based international oil services company); Director of Computershare Trust Company of Canada (a private Canadian company that manages the administration of shareholder and employee records from public and private companies throughout North America).
Dale Blue(2) Mississauga, Ontario, Canada	Director since 2006(7)	27	Independent consultant with over thirty years experience in financial services; has served on numerous domestic and international Boards.
David J. Boone(3) Calgary, Alberta, Canada	Director since 2006(7)	8,755	Professional Engineer; President and CEO of Barrick Energy (the oil and gas division of Barrick Gold Corp.); prior thereto, President, Escavar Energy Inc. (a private oil and natural gas company), 2003 to mid-2008.
William Friley(4) Calgary, Alberta, Canada	Director since 2006(7)	3,999	President and Chief Executive Officer of Telluride Oil and Gas Ltd. (a private oil and natural gas company), President of Skyeland Oils Ltd. (a private oil and natural gas company), and Chairman of TimberRock Energy Corporation (a private oil and natural gas company); Lead Director of OFUM Oilsands Corp. (a private company) and Director of Silver Star Energy Services (a private company); Prior thereto, President and Chief Executive Officer of Triumph Energy Corporation (a public oil and natural gas company); Previously Director of Mustang Resources Inc. (a public oil and natural gas company); Past Chair of Canadian Association of Petroleum Producers.

Name and Municipality of Residence	Position with Harvest Operations	No. of Trust Units Held [1]	Principal Occupation
William D. Robertson[2] Calgary, Alberta, Canada	Director since 2008[7]	2,052	Fellow Chartered Accountant, (Retired) Partner of PricewaterhouseCoopers LLP where he acted as lead oil and gas specialist. 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. Currently, Mr. Robertson serves on the boards of several public companies in the energy sector.
John Zahary Calgary, Alberta, Canada	President & Chief Executive Officer, Director since 2008[7]	133,103[6]	Professional Engineer, President and Chief Executive Officer of Harvest Operations since February 2006. From May 11, 2004 was President and Chief Executive Officer of VHI; and prior thereto was President of Petrovera Resources.
Robert Fotheringham Calgary, Alberta, Canada	Chief Financial Officer	35,845	Chartered Accountant, Chief Financial Officer of Harvest Operations since February 2006; From June 2004 to February 2, 2006 was Vice President, Finance and Chief Financial Officer of VHI; and, from February 2003 to April 2004 was Chief Financial Officer of Inter Pipeline Fund.
Rob Morgan Calgary, Alberta, Canada	Chief Operating Officer - Upstream	36,758	Professional Engineer, Chief Operating Officer - Upstream of Harvest Operations since February 2, 2006. Prior thereto was Vice President, Operations and Corporate Development of VHI since June 2004; Manager, Planning at Canadian Natural Resources Limited (a public oil and natural gas company) from March 2004 to June 2004; Vice President Corporate Development, and Vice President Engineering of Petrovera Resources (a private oil and natural gas company) from May 1999 to March 2004.
Brad Aldrich St Louis, Missouri, USA	Chief Operating Officer - Downstream	20,000	Engineer, on November 26, 2007 appointed Chief Operating Officer - Downstream; from 2006 to June 2007 was President & Chief Operating Officer of Changing World Technologies; from 2005 to 2006 was Vice President of Thermodyne Holdings Corp.; and prior thereto was Vice President, Production Yukos Oil Company
Gary Boukall Calgary, Alberta, Canada	Vice President, Geosciences	13,714	Professional Geologist, on March 16, 2007 appointed Vice President, Geosciences of Harvest Operations; from December 2002 to March 2007 held various positions with Harvest Operations including Chief Geologist, Manager of Geology and Manager of Geosciences.

Name and Municipality of Residence	Position with Harvest Operations	No. of Trust Units Held [(1)]	Principal Occupation
James Sheasby Calgary, Alberta, Canada	Vice President, Engineering	4,823	Professional Engineer; on March 16, 2007 appointed to Vice President, Engineering of Harvest Operations; from February 2, 2006 to March 2007 was Manager, Engineering of Harvest Operations; from November 2005 to February 2, 2006 was Manager, Engineering of VHI; from November 2004 to October 2005 was Vice President, Engineering of Hygait Resources; from February 2004 to October 2004 was an Exploitation Engineer at Canadian Natural Resources Ltd.; and prior thereto was a Team Lead at Petrovera Resources
Neil Sinclair Calgary, Alberta, Canada	Vice President, Operations	11,393	On March 16, 2007 was appointed Vice President, Operations of Harvest Operations; from February 2, 2006 to March 2007 was Manager, Operations of Harvest Operations; from June 9, 2004 to February 2, 2006 was Manager, Operations of VHI; from February 2004 to June 2004 was Manager of Technical Services of Penn West Petroleum Ltd.; and prior thereto was Manager, Operations at Petrovera Resources
Phil Reist Calgary, Alberta, Canada	Vice President, Controller	9,873	Chartered Accountant; on March 16, 2007 was appointed Vice President, Controller of Harvest Operations; from February 2, 2006 to March 2007 was Controller of Harvest Operations; from September 2005 to February 2, 2006 was Controller of VHI; from March 2004 to June 2005 was Vice President, Controller of Penn West Petroleum Ltd.; and prior thereto was Vice President, Finance and Controller of Petrovera Resources
Les Hogan Calgary, Alberta, Canada	Vice President, Land	Nil	Landman; on December 3, 2007 was appointed Vice President, Land of Harvest Operations; from June 2002 to November 2007 held various positions including Vice President Land and Community Affairs at Pioneer Natural Resources Canada.
David J. Rain Calgary, Alberta, Canada	Corporate Secretary	68,623	Chartered Accountant; Corporate Secretary of Harvest Operations since June 2002 and since June 1999 was Vice President, Finance and Chief Financial Officer and a Director of Caribou Capital Corp. (an investment management company); from July 2004 to February 2, 2006 was Vice President and Chief Financial Officer of Harvest Operations; and prior thereto was Vice President, Finance and Chief Financial Officer of Petrobank Energy and Resources Ltd.
Steven Saunders Calgary, Alberta, Canada	Assistant Corporate Secretary and Director of Taxation	5,124	Chartered Accountant; on March 16, 2007, was appointed Assistant Corporate Secretary of Harvest Operations and relinquished the Treasurer role; on February 2, 2006 to March 2007 was Treasurer of Harvest Operations and since November 2004 also the Director of Taxation; and prior thereto was International Tax Analyst with EnCana Corporation
Dean Beacon Calgary, Alberta, Canada	Treasurer	1,553	On March 16, 2007 appointed Treasurer of Harvest Operations; and prior thereto was a Senior Advisor, Corporate Finance at Talisman Energy Inc.

Notes:

(1) Represents all Trust Units beneficially owned, controlled or directed, directly or indirectly as at March 24, 2009. Based upon information provided by the director or officer to the Trust.
(2) Member of the Audit Committee.
(3) Member of the Reserves, Safety and Environment Committee.
(4) Member of the Compensation and Corporate Governance Committee.
(5) Includes Trust Units held by entities controlled by Mr. Chernoff, and Trust Units held in RESP accounts for the benefit of Mr. Chernoff's children.
(6) Includes 11,466 Trust Units held by Mr. Zahary's spouse.
(7) The terms of office of all of the directors will expire at the next annual Unitholders' meeting of the Trust.

As at March 24, 2009, the directors and executive officers of Harvest Operations and their associates and affiliates, as a group, beneficially owned, or controlled or directed, directly or indirectly, approximately 7,238,127 Trust Units or approximately 4.5% of the outstanding Trust Units.

Corporate Cease Trade Orders or Bankruptcies

Mr. John A. Brussa was a director of Imperial Metals Limited, a corporation engaged in oil and natural gas and mining operations, in the year prior to that corporation implementing a plan of arrangement under the *Company Act* (British Columbia) and under the *Companies' Creditors Arrangement Act* (Canada), which resulted in the separation of its two businesses. The reorganization resulted in the creation of two public corporations: Imperial Metals Corporation and IEI Energy Inc. (subsequently renamed Rider Resources Ltd.). The plan of arrangement was completed in April 2002.

Mr. Verne G. Johnson was a director of Mystique Energy Inc., a corporation engaged in oil and gas operations that sought and was granted protection under the *Companies' Creditors Arrangement Act* (Canada) in April 2007. The corporation sold all of its assets under Court direction in July 2007 and repaid all outstanding debt and creditors.

Other than the items referenced above, to our knowledge, no director or executive officer of Harvest Operations is, or has been in the last ten years, a director, chief executive officer or chief financial officer of an issuer (including the Trust) that, (i) while that person was acting in that capacity was the subject of a cease trade order or similar order or an order that denied the issuer access to any exemptions under securities legislation, for a period of more than 30 consecutive days, (ii) was subject to an event that occurred while that person was acting in the capacity of director, chief executive officer or chief financial officer, which resulted, after that person ceased to be a director, chief executive officer or chief financial officer, in the issuer being the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under securities legislation, for a period of more than 30 consecutive days, or (iii) while that person was acting in the capacity or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Penalties or Sanctions or Personal Bankruptcy

No director, executive officer or Unitholder holding a sufficient number of Trust Units to affect materially the control of the Trust: (i) has been subject to, (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision; or (ii) has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangements or compromises with creditors, or had a receiver, receiver manager or trustee appointed to hold his or its assets.

Conflicts of Interest

Directors and officers of Harvest Operations may, from to time, be involved with the business and operations of other oil and gas issuers, in which case a conflict may arise (see "Risk Factors"). Properties will not be acquired from officers or directors of Harvest Operations or persons not at arm's length with such persons at prices which are greater than fair market value, nor will Properties be sold to officers or directors of Harvest Operations or persons not at arm's length with such persons at prices which are less than fair market value in each case as established by an opinion of an independent financial advisor and approved by the independent members of the Harvest Board. There may be circumstances where certain transactions may also require the preparation of a formal valuation and the affirmative vote of Unitholders in accordance with the requirements of Multilateral Instrument 61-101.

Circumstances may arise where members of the Harvest Board serve as directors or officers of corporations which are in competition with the interests of Harvest Operations and the Trust. No assurances can be given that opportunities identified by such board members will be provided to Harvest Operations and the Trust.

LEGAL AND REGULATORY PROCEEDINGS

There are no legal proceedings which the Trust or any subsidiary of the Trust is or was a party to, or that any of their property is or was the subject of during the year ended December 31, 2008, nor are there any proceedings known to Harvest to be contemplated that involves a claim for damages exceeding ten per cent of our current assets, other than methyl tertiary butyl ether ("**MTBE**") proceedings against North Atlantic in *The State of New Hampshire versus Amerada Hess Corp. et al*, in of more than 100 MTBE product liability litigation cases that have been consolidated for pre-trial purposes in this matter. The plaintiffs seek relief for alleged contamination of ground water from the various defendants' use of the gasoline additive MTBE. Although the plaintiffs have not made a particular monetary demand, they are asserting collective and joint liability against all defendants. All consolidated law suits are at a preliminary stage and, accordingly, it is too early in the legal process to reach any conclusion regarding the ability of the State of New Hampshire to properly assert jurisdiction over North Atlantic in the lawsuit or to reach any conclusions regarding the substance of the plaintiffs' claims. Accordingly, the evaluation of the risk of liability to North Atlantic is not determinable at this time and no amounts are accrued in the combined financial statements in respect of this matter. In addition, Harvest received an indemnity under the Purchase and Sale Agreement from the vendor of the shares of North Atlantic, Vitol Group B.V., in respect of this contingent liability.

There were no penalties or sanctions imposed against the Trust or any subsidiary of the Trust by a court relating to securities legislation or by a securities regulatory authority during the year ended December 31, 2008 or any other penalties or sanctions imposed by a court or regulatory body against the Trust or any subsidiary of the Trust that would likely be considered important to a reasonable investor in making an investment decision. No settlement agreements were entered into by the Trust or any subsidiary of the Trust with a court relating to securities legislation or with a securities regulatory authority during the year ended December 31, 2008.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and executive officers of the Trust, any person or company that beneficially owns, or controls or directs, directly or indirectly more than 10% of the outstanding Trust Units, or any known associate or affiliate of such persons or company, in any transaction within the three most recently completed financial years or during the current financial year.

TRANSFER AGENT AND REGISTRAR

Valiant Trust Company, at its principal offices in Calgary, Alberta, is the transfer agent and registrar of the Trust Units, 9% Debentures Due 2009, 8% Debentures Due 2009, 6.5% Debentures Due 2010, 7.25% Debentures Due 2013, 7.25% Debentures Due 2014, and 7.5% Debentures Due 2015. The transfer agent and registrar of the 10.5% Debentures due 2008 and 6.40% Debentures Due 2012 is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by the Trust within the most recently completed financial year, or before the most recently completed financial year but still in effect, are the following:

1. the Trust Indenture between Harvest Operations Corp. and Valiant Trust Company described in "Trust Indenture";

2. the Indenture between Harvest Energy Trust, Harvest Operations Corp. and Valiant Trust Company entered into in connection with the 9% Debentures Due 2009, 8% Debentures Due 2009, 6.5% Debentures Due 2010, 7.25% Debentures Due 2013, 7.25% Debentures Due 2014, and 7.50% Debentures Due 2015 and the Debenture Indenture between Viking Energy Royalty Trust and Computershare Trust Company of Canada entered into in connection with the 10.5% Debentures Due 2008 and 6.40% Debentures Due 2012 described in “General Description of Capital Structure – Debentures and the Debenture Indenture”;

3. the Indenture between Harvest Operations Corp., the Subsidiary Guarantors, Harvest Energy Trust and U.S. Bank National Association entered into in connection with the $7^{7/8}$% Senior Notes;

4. Amended and Restated Credit Agreement dated October 19, 2006;

5. the May 7, 2007 Amending Agreement to the Amended and Restated Credit Agreement; and

6. the Trust's Trust Unit Rights Incentive Plan and Unit Award Incentive Plan.

Copies of each of these documents have been filed on SEDAR at www.sedar.com.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Trust during, or related to, the Trust's most recently completed financial year other than McDaniel and GLJ, the Trust's Independent Reserve Engineering Evaluators and KPMG LLP, the Trust's auditors. As at the date hereof, none of the principals of McDaniel and GLJ as a group, directly or indirectly, owned more than 1% of the Units and KPMG LLP has advised Harvest's Audit Committee that they are independent with respect to the Trust within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Trust or of any associate or affiliate of the Trust except for John A. Brussa, a director of Harvest Operations, who is a partner at Burnet, Duckworth & Palmer LLP which law firm renders legal services to Harvest.

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a Canadian issuer listed on the New York Stock Exchange (the "**NYSE**"), we are not required to comply with most of the NYSE rules and listing standards and instead may comply with domestic requirements. As a foreign private issuer, we are only required to comply with three of the NYSE Rules (i) have an audit committee that satisfies the requirements of the *United States Securities Exchange Act of 1934*; (ii) the Chief Executive Officer must promptly notify the NYSE in writing after an executive officer becomes aware of any material non-compliance with the applicable NYSE Rules; and (iii) provide a brief description of any significant differences between our corporate governance practices and those followed by U.S. companies listed under the NYSE. The Trust has disclosed in the corporate governance section of its website at www.harvestenergy.ca that it does not have an internal audit function. Except as described, the Trust is in compliance with the NYSE corporate governance standards in all other significant respects.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of securities and interests of insiders in material transactions, where applicable, is contained in the Trust's Information Circular – Proxy Statement dated March 24, 2009 which relates to the Annual and Special Meeting of Unitholders to be held on May 19, 2009. Additional financial information is provided in Harvest's audited consolidated financial statements and notes thereto for the year ended December 31, 2008 and Harvest's management discussion and analysis for the year ended December 31, 2008 which may be found on SEDAR at www.sedar.com.

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Harvest Operations Corp. ("**Harvest Operations**") on behalf of Harvest Energy Trust (the "**Trust**") are responsible for the preparation and disclosure of information with respect to Harvest Operations' and the Trust's other subsidiaries' oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated Harvest Operations' and the Trust's other subsidiaries' reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves, Safety & Environment Committee (the "**RSE Committee**") of the board of directors of Harvest Operations has:

(a) reviewed Harvest Operations' procedures for providing information to the independent qualified reserves evaluators;

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

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

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

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

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

(c) the content and filing of this report.

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

(signed) "John Zahary"
John Zahary
President & CEO

(signed) "Rob Morgan"
Rob Morgan
Vice President, Engineering & COO

(signed) "David Boone"
David Boone
Director and Chairman of the RSE Committee

(signed) "Verne Johnson"
Verne Johnson
Director and Member of the RSE Committee

March 27, 2009

APPENDIX B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

To the Board of directors of Harvest Operations Corp. (the "**Harvest Operations**"):

1. We have evaluated Harvest Operations' and Harvest Energy Trust's other subsidiaries' reserves data as at December 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.

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

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

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

5. The following table sets forth the estimated future net revenue (before deductions of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs, and calculated using a discount rate of 10 percent, included in the reserves data of Harvest Operations evaluated by us for the year ended December 31, 2008. This table also identifies the respective portions thereof that we have evaluated and reported on to Harvest Operations' Management and Board of directors.

			Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate)($M)			
Independent Qualified Reserves Evaluator or Auditor	Preparation Date of Evaluation Report	Location of Reserves	Audited	Evaluated	Reviewed	Total
McDaniel and Associates Consultants Ltd.	March 13, 2009	Canada	-	1,449,155	-	1,449,155
GLJ Petroleum Consultants Ltd.	March 9, 2009	Canada	-	2,445,133	-	2,445,133
Totals			-	3,894,288	-	3,894,288

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

7. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective dates.

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

Executed as to our report referred to above:

(Signed) McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

March 13, 2009

(Signed) GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

March 17, 2009

APPENDIX C

HARVEST OPERATIONS CORP. AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the board of directors is attached hereto as Appendix "D". The members of the Audit Committee are Dale Blue, Hector McFadyen, and William Robertson.

Composition of the Audit Committee

The Board of Directors has determined that each member of the Audit Committee is an "independent" director and "financially literate" in accordance with National Instrument 52-110. In considering criteria for the determination of financial literacy, the Board of Directors looked at the ability to read and understand a balance sheet, an income statement and cash flow statement of a public company as well as the director's past experience in reviewing or overseeing the preparation of financial statements.

Relevant Education and Experience

Name (Director Since)	Principal Occupation & Biography
Mr. Dale Blue (February 2006) <u>Other Canadian Public Board of Director Memberships</u> None	Mr. Blue received a Bachelor of Arts degree in economics from the University of Manitoba and has over thirty years experience in the financial services industry and has held senior positions with Chase Manhattan Bank of Canada and Chase Manhattan Bank in New York. He has also served on the Board of Directors of numerous Canadian public companies and various private companies.
Mr. Hector McFadyen (December 2002) <u>Other Canadian Public Board of Director Memberships</u> None	Mr. McFadyen has a Masters of Arts degree in economics from the University of Calgary and a Bachelor of Arts degree in economics from Sir George Williams University and has accumulated over 35 years of oil and natural gas industry experience primarily with a senior producer based in Alberta with significant international business interests where he served as a member of the senior management team. He currently serves as a Director of Hunting PLC (a public UK based international oil services company) and privately-held Computershare Trust Company of Canada.
Mr. William D. Robertson (August 2008) <u>Other Canadian Public Board of Director Memberships</u> Inter Pipeline Fund Cinch Energy Corp.	Mr. Robertson is a Fellow Chartered Accountant and was formerly the lead oil and gas specialist at Price Waterhouse and PriceWaterhouseCoopers in Calgary. After enjoying a 36-year career with the firm, Mr. Robertson retired from practice in 2002. Prior to this, he served on the CIM Petroleum Society Standing Committee on Reserve Definitions, the Financial Advisory Committee of the Alberta Securities Commission, the working sub committee of the Alberta Securities Commission on Oil and Gas Reporting and the Council of the Institute of Chartered Accountants of Alberta. Mr. Robertson graduated with a Bachelor of Commerce degree from the University of Alberta.

Pre-Approval of Policies and Procedures

All non-audit or special services performed by any independent accountants must be first approved by the Audit Committee. All remuneration provided to the Trust's auditor and any independent accountants are also approved by the Audit Committee. The Trust'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.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by the Trust's external auditor in each of the last two fiscal years for audit services (audit and review of Harvest's annual financial statements and review of quarterly financial statements), were $935,000 in 2008 and $1,042,650 in 2007.

Audit and Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance related services by the Trust's external auditor that are reasonably related to the performance of the audit or review of the Trust's financial statements that are not reported under "Audit Fees" above were $75,000 in 2008 and $369,000 in 2007. These fees are primarily related to prospectus comfort letters and French translation fees.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by the Trust's external auditor for regular tax compliance, tax advice and tax planning were nil in 2008 and 2007.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for products and services provided by the Trust's auditors other than services reported above were nil in 2008 and nil in 2007.

APPENDIX D

HARVEST OPERATIONS CORP. AUDIT COMMITTEE MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Harvest Operations Corp. ("**Harvest Operations**") 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 are as follows:

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

2. to provide better communication between directors and external auditors;

3. to enhance the external auditor's independence;

4. to increase the credibility and objectivity of financial reports; and

5. to strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

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 "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. The Board shall appoint the Committee Chair, who shall be an unrelated director.

3. 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.

Mandate and Responsibilities of Committee

1. It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors 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:

   (a) identifying, monitoring and mitigating business risks; and

   (b) 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:

   (a) 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;

   (b) reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

   (c) reviewing accounting treatment of unusual or non-recurring transactions;

   (d) ascertaining compliance with covenants under loan agreements;

   (e) reviewing disclosure requirements for commitments and contingencies;

   (f) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

   (g) reviewing unresolved differences between management and the external auditors; and

   (h) obtain explanations of significant variances with comparative reporting periods.

4. The Committee is to review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**") 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 assess the accuracy of those procedures.

5. With respect to the appointment of external auditors by the Board, the Committee shall:

   (a) recommend to the Board the external auditors to be nominated;

   (b) recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee;

   (c) on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Trust to determine the auditors' independence;

   (d) when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

   (e) review and pre-approve any non-audit services to be provided to Harvest or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. 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 auditors (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 auditors 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:

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

   (b) 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 auditors 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.

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. 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 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 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 Harvest Operations 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. 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.

9. 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 Operations.

10. 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 close of the next annual meeting of Unitholders following appointment as a member of the Committee.

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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of the financial condition and results of operations of Harvest Energy Trust should be read in conjunction with our audited consolidated financial statements and accompanying notes for the years ended December 31, 2008 and 2007. The information and opinions concerning our future outlook are based on information available at March 2, 2009.

In this MD&A, reference to "Harvest", "we", "us" or "our" refers to Harvest Energy Trust and all of its controlled entities on a consolidated basis. All references are to Canadian dollars unless otherwise indicated. Tabular amounts are in thousands of dollars unless otherwise stated. Natural gas volumes are converted to barrels of oil equivalent ("boe") using the ratio of six thousand cubic feet ("mcf") of natural gas to one barrel of oil ("bbl"). Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf to 1 bbl is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. In accordance with Canadian practice, petroleum and natural gas revenues are reported on a gross basis before deduction of Crown and other royalties. In addition to disclosing reserves under the requirements of National Instrument 51-101, we also disclose our reserves on a company interest basis which is not a term defined under National Instrument 51-101. This information may not be comparable to similar measures by other issuers.

NON-GAAP MEASURES

Throughout this MD&A we have referred to certain measures of financial performance that are not specifically defined under Canadian GAAP. Cash G&A and Operating Netbacks are non-GAAP measures used extensively in the Canadian energy trust sector for comparative purposes. Cash G&A are G&A expenses excluding the effect of our unit based compensation plans, while Operating Netbacks are always reported on a per boe basis, and include gross revenue, royalties, operating expenses, and transportation and marketing expenses. Gross Margin is also a non-GAAP measure and 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. Earnings From Operations is also a non-GAAP measure and is commonly used in the petroleum and natural gas and refining industries to reflect operating results before items not directly related to operations.

FORWARD-LOOKING INFORMATION

This MD&A highlights significant business results and statistics from our consolidated financial statements for the year ended December 31, 2008 and the accompanying notes thereto. In the interest of providing our Unitholders and potential investors with information regarding Harvest, including our assessment of our future plans and operations, this MD&A contains forward-looking statements that involve risks and uncertainties. Such risks and uncertainties include, but are not limited to, risks associated with conventional petroleum and natural gas operations; risks associated with refining and marketing operations; the volatility in commodity prices and currency exchange rates; risks associated with realizing the value of acquisitions; general economic, market and business conditions; changes in environmental legislation and regulations; the availability of sufficient capital from internal and external sources and such other risks and uncertainties described from time to time in our regulatory reports and filings made with securities regulators.

Forward-looking statements in this MD&A include, but are not limited to, the forward looking statements made in the "Outlook" section as well as statements made throughout with reference to production volumes, refinery throughput volumes, royalty rates, operating costs, commodity prices, administrative costs, price risk management activity, acquisitions and dispositions, capital spending, reserve estimates, distributions, access to credit facilities, capital taxes, income taxes, cash from operating activities, and regulatory changes. For this purpose, any statements that are contained herein that are not statements of historical fact may be deemed to be forward-looking statements. Forward-looking statements often contain terms such as "may", "will", "should", "anticipate", "expects", and similar expressions.

Readers are cautioned not to place undue reliance on forward-looking statements as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. Although we consider such information reasonable at the time of preparation, it may prove to be incorrect and actual results may differ materially from those anticipated. We assume no obligation to update forward-looking statements should circumstances, estimates or opinions change, except as required by law. Forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

Consolidated Financial and Operating Highlights – 2008

- Cash from operating activities of $655.9 million, relatively unchanged from $641.3 million in the prior year, as a $321.6 million improvement in the contribution from upstream operations was substantially offset by a $174.5 million increase in the cash settlements on price risk management contracts, an $81.4 million drop in contribution from downstream operations and a $19.1 million realized loss on currency exchange transactions as compared to a gain of $53.6 million in the prior year.
- Upstream operations contributed $945.9 million of cash reflecting average daily production of 55,932 boe with strong commodity prices more than offsetting a strengthening Canadian dollar, lower production and higher operating costs.
- Upstream production was bolstered with the acquisition of 2,650 boe/d of producing assets in the Third Quarter for cash consideration of $167.6 million, representing a cost per flowing barrel of approximately $63,000.
- Capital spending of $271.3 million in our upstream business, plus $128.8 million of net acquisitions, replaced our 2008 production with finding and development costs, including changes in future development costs, of $25.97 per boe of proved reserves and $29.87 per boe for proved plus probable reserves.
- Downstream operations contributed $83.6 million of cash reflecting sound operating performance more than offset by generally lower refining margins as high commodity prices during the first three quarters increased our cost of purchased energy and lower commodity prices in the Fourth Quarter resulted in an inventory write-down.
- Capital expenditures in our downstream operations totaled $56.2 million, including the commissioning of our $30.1 million visbreaker expansion project in November, which is expected to upgrade approximately 1,500 bbls/d of high sulphur fuel oil (“HSFO”) to distillate yield.
- Record high commodity prices resulted in $200.8 million of cash settlements on our price risk management contracts with $225.2 million of net cash settlements during the first three quarters offset by $24.4 million of settlements in our favour during the Fourth Quarter.
- Balance sheet liquidity was improved with the issuance of $250 million principal amount of 7.5% Convertible Unsecured Subordinated Debentures for net proceeds of $239.5 million in April 2008.
- Declared distributions totaling $551.3 million ($3.60 per Trust Unit) reflecting an 84% payout ratio based on cash from operating activities and 81% payout ratio if asset retirement expenditures and non-capital working capital are excluded from the cash flow.

SELECTED INFORMATION

The table below provides a summary of our financial and operating results for the years ended December 31, 2008, 2007 and 2006.

	Year Ended December 31		
($000s except where noted)	**2008**	2007	2006
Revenue, net[1]	**5,489,364**	4,069,600	1,380,825
Cash From Operating Activities	**655,887**	641,313	507,885
Per Trust Unit, basic	**$ 4.29**	$ 4.63	$ 5.00
Per Trust Unit, diluted	**$ 4.05**	$ 4.30	$ 4.84
Net Income (Loss)[2]	**212,019**	(25,676)	136,046
Per Trust Unit, basic	**$ 1.39**	$ (0.19)	$ 1.34
Per Trust Unit, diluted	**$ 1.39**	$ (0.19)	$ 1.33
Distributions declared	**551,325**	610,280	468,787
Distributions declared, per Trust Unit	**$ 3.60**	$ 4.40	$ 4.53
Distributions declared as a percentage of Cash From Operating Activities	**84%**	95%	92%
Bank debt	**1,226,228**	1,279,501	1,595,663
$7^{7/8}$% Senior Notes	**298,210**	241,148	291,350
Convertible Debentures[3]	**827,759**	651,768	601,511
Total long-term financial debt[3]	**2,352,197**	2,172,417	2,488,524
Total assets	**5,745,407**	5,451,683	5,745,558
UPSTREAM OPERATIONS			
Daily Production			
Light to medium oil (bbl/d)	**25,093**	27,165	27,482
Heavy oil (bbl/d)	**12,162**	14,469	13,904
Natural gas liquids (bbl/d)	**2,624**	2,412	2,247
Natural gas (mcf/d)	**96,315**	97,744	96,578
Total daily sales volumes (boe/d)	**55,932**	60,336	59,729
Operating Netback ($/boe)	**47.89**	29.89	30.54
Cash capital expenditures	**271,312**	300,674	376,881
Business and property acquisitions, net	**128,773**	138,156	2,467,097
DOWNSTREAM OPERATIONS			
Average daily throughput (bbl/d)	**103,497**	98,617	86,890
Average Refining Margin (US$/bbl)	**7.16**	10.05	9.32
Cash capital expenditures	**56,162**	44,111	21,411

(1) Revenues are net of royalties.

(2) Net Income (Loss) includes a future income tax expense of $108.6 million (2007 – an expense of $65.8 million; 2006 – a recovery of $2.3 million) and an unrealized net gain from risk management activities of $185.9 million (2007 - net losses of $147.8 million; 2006 – net gains of $52.2 million) for the year ended December 31, 2008. Please see Notes 18 and 20 to the Consolidated Financial Statements for further information.

(3) Includes current portion of Convertible Debentures.

(4) Downstream operations acquired on October 19, 2006.

REVIEW OF OVERALL PERFORMANCE

Harvest is an integrated energy trust with our petroleum and natural gas business focused on the operation and further development of assets in western Canada (our "upstream operations") and our refining and marketing business focused on the safe operation of a medium gravity sour crude oil hydrocracking refinery and a retail and wholesale petroleum marketing business both located in the Province of Newfoundland and Labrador (our "downstream operations"). Our earnings and cash flow from operating activities are largely determined by the realized prices for our crude oil and natural gas production as well as refined product crack spreads, including the effects of changes in the U.S. dollar to Canadian dollar exchange rate. Recently, changes in crude oil and natural gas prices and the exchange rate between U.S. dollars and Canadian dollars have moved together with changes in the currency exchange rate partially offsetting changes in crude oil and natural gas prices.

During 2008, cash from operating activities totaled $655.9 million, a $14.6 million increase as compared to $641.3 million in the prior year. While cash generated from our upstream operations of $945.9 million in 2008 was a significant improvement from the $624.3 million in the prior year, the cash generated in our downstream operations of $83.6 million was approximately half the $165.0 million generated in the prior year. The $321.6 million improvement in our upstream operations reflects the year-over-year strength in commodity prices as well as a tightening of heavy crude oil differentials in western Canada. The reduced contribution from our downstream operations should be considered in light of the generally weaker refined product crack spreads in 2008 as well as the impact of significantly lower commodity prices in the Fourth Quarter resulting in inventory write-downs of $35.3 million. The average exchange rate between the Canadian dollar and U.S. dollar was relatively unchanged year-over-year with the 2008 year-end exchange rate of Cdn$1.00 to US$0.80 reflecting a significant strengthening of the U.S. dollar in the last half of 2008 which bolstered our realized crude oil prices and refined product crack spreads, both of which are denominated in U.S. dollars.

Our upstream operations averaged production of 55,932 boe/d in 2008 as compared to 60,336 boe/d in the prior year, reflecting a 7% reduction. Our production in 2008 reflects a modest 4% decline as compared to the 58,416 boe/d averaged in the Fourth Quarter of 2007 as our reduced capital program in 2008 and net acquisitions substantially stabilized our production. In 2007, we benefited from a $148.5 million drilling effort in the First Quarter boosting production to an average of 62,024 boe/d for the quarter as compared to capital expenditures of $79.6 million in the First Quarter of 2008. In 2008, we shifted our efforts to the re-pressurization of a few of our larger oil reservoirs rather than further development drilling and are expecting longer term more stable benefits, as compared to the flush production and accelerated declines associated with some drilling programs. Our operating costs of $300.9 million in 2008 are unchanged from the prior year as the overheated Alberta oilfield services industry did not weaken until late in the year with continued weakening expected in 2009. Our operating netback of $47.89 per boe represents a 60% increase over the prior year and is primarily attributed to higher commodity prices and tightening heavy crude oil differentials in western Canada.

During the Third Quarter of 2008, we completed two acquisitions for an aggregate cash consideration of $167.6 million to acquire approximately 1,645 bbls/d of light oil and 6,200 mcf/d of natural gas which represents an acquisition cost of approximately $63,000 per flowing boe. The principal asset acquired was a large pool of medium gravity oil of which approximately 7% of the original oil in place has been recovered and it is anticipated that with a combination of additional drilling and reservoir management, the recoveries from this pool can be substantially improved. In addition to numerous minor acquisitions/dispositions, we disposed of 481 boe/d of natural gas and natural gas liquids production for $36.8 million, representing proceeds of approximately $76,000 per flowing boe.

Reserve additions in our upstream operations replaced our production during 2008 with our proved plus probable reserves at December 31, 2008 totaling 219.9 million boe substantially unchanged from 220.9 million boe at the end of 2007. Including changes in future development costs, our 2008 finding and development costs averaged $25.97 per boe of proved reserves as compared to $28.44 per boe in the prior year and a three year average of $27.27 per boe while our finding and development costs averaged $29.87 per boe for proved plus probable reserves as compared to $28.10 per boe in the prior year and a three year average of $28.00 per boe. Including changes in future development costs, our 2008 finding, development and acquisition costs averaged $27.90 per boe of proved reserves as compared to $26.98 per boe in the prior year and a three year average of $28.78 per boe while on a proved plus probable basis, our costs were $28.84 per boe in 2008 as compared to

$22.97 per boe in the prior year and a three year average of $25.47 per boe, respectively. Proved plus probable reserve additions are 13.7 million boe attributed to our 2008 capital program, enhanced oil recovery plans and new undeveloped reserves which, when coupled with the 5.8 million boe acquired during the year, substantially offsets our 2008 production. Relative to our 2008 netback price of $47.89, our finding and development costs represent a recycle ratio of 1.6 while our finding, development and acquisition costs represent a recycle ratio of 1.7.

During 2008, our downstream operations generated $83.6 million of cash as compared to $165.0 million in the prior year with the reduced contribution primarily the result of an $86.8 million drop in gross margin. The drop in North American demand for gasoline that began in mid-2007 continued through 2008 with the slowing US economy and record high prices curtailing consumer driving. As a result, the gasoline crack spread weakened significantly from the US$28.76 averaged during the Second Quarter of 2007 culminating in a negative spread during the Fourth Quarter of 2008. Similarly, the prices for high sulphur fuel oil ("HSFO") during the first half of 2008 did not proportionately reflect increases in crude oil prices resulting in a significant deterioration of the HSFO crack spread which averaged US$38.75 less than the West Texas Intermediate ("WTI") benchmark price of US$123.98/bbl during the Second Quarter of 2008 as compared to an average of US$26.52/bbl less than the WTI benchmark for the entire year. In contrast, the strong global demand for distillate products improved the refining margins for heating oil, diesel and jet fuel. Overall, our refining margin in 2008 was US$7.16 per barrel of throughput, a drop of $2.89 per barrel from the prior year.

Our refinery throughput averaged 103,497 bbls/d during 2008 with First Quarter throughput of approximately 112,000 bbls/d somewhat tempered by a four day unplanned outage. Throughput in May through August was reduced to approximately 95,500 bbls/d to optimize margins by minimizing the production of HSFO and reduced to approximately 102,800 bbls/d from September through December due to fouling of heat exchangers. Average daily throughput in 2008 represents a utilization factor of 90% as compared to the refinery's 115,000 bbls/d nameplate capacity. As compared to the prior year with $34.5 million of turnaround and catalyst costs incurred during an extensive shutdown in the Fourth Quarter, our refinery operations incurred $5.6 million of turnaround and catalyst costs during a partial turnaround of the visbreaker unit in 2008. Our refinery operating costs totaled $78.9 million ($2.08 per bbl of throughput) in 2008 as compared to $83.9 million ($2.33 per bbl of throughput) in the prior year while our cost of purchased energy was $131.9 million ($3.48 per bbl) in the current year as compared to $92.3 million ($2.57 per bbl) in 2007 which when aggregated totals $5.56 per barrel of throughput for 2008 as compared to $4.90 in the prior year, a net increase of $0.66 per barrel.

In 2008, the strength in commodity prices resulted in cash settlements paid of $225.2 million on our price risk management contracts during the first nine months of 2008, offset somewhat by $24.4 million received during the Fourth Quarter of the year as commodity prices weakened significantly.

In April 2008, we raised $239.5 million of net proceeds with the issuance of $250 million principal amount of 7.5% Convertible Unsecured Subordinated Debentures and applied the net proceeds to reduce borrowings under our Extendible Revolving Credit Facility. As the disruptions in the capital markets continued in 2008, we have deferred our request to extend the maturity date of our credit facility beyond April 2010 in an effort to maintain the cost of our bank borrowing as well as retain our $1.6 billion of credit capacity.

In 2008, we declared distributions to Unitholders totaling $551.3 million ($3.60 per Trust Unit) as compared to $610.3 million ($4.40 per Trust Unit) in 2007. We have maintained a monthly distribution of $0.30 per Trust Unit since November 2007 and in light of the significant reduction in commodity prices, we have declared a distribution of $0.05 per Trust Unit for Unitholders of record on March 23, 2009 and payable on April 15, 2009. In the near term, substantially all of our cash flow from operating activities will be directed to enhancing Unitholder value through capital expenditures focused on maintaining our productive capacity as well as low risk profit/growth initiatives with the remaining cash directed towards improving our balance sheet liquidity by repaying bank borrowings.

Business Segments

The following table presents selected financial information for our two business segments:

	Year Ended December 31					
	2008			2007		
(in $000s)	**Upstream**	**Downstream**	**Total**	Upstream	Downstream	Total
Revenue[(1)]	**1,294,769**	**4,194,595**	**5,489,364**	971,044	3,098,556	4,069,600
Earnings From Operations[(2)]	**498,786**	**14,125**	**512,911**	169,423	92,270	261,693
Capital expenditures	**271,312**	**56,162**	**327,474**	300,674	44,111	344,785
Total assets[(3)]	**3,933,632**	**1,775,688**	**5,745,407**	3,952,337	1,482,904	5,451,683

(1) Revenues are net of royalties.

(2) This is a non-GAAP measure; please refer to "Non-GAAP Measures" in this MD&A.

(3) Total assets on a consolidated basis as at December 31, 2008 include $36.1 million (2007 - $16.4 million) relating to the fair value of risk management contracts.

Our upstream and downstream operations are each discussed separately in the sections that follow. Additionally, we have included a section entitled "Risk Management, Financing and Other" that discusses, among other things, our cash flow risk management program.

UPSTREAM OPERATIONS

2008 Highlights

- Operating cash flow of $945.9 million, an improvement of $321.6 million over the prior year, reflecting the year-over-year strength of crude oil prices as well as a tightening of quality differentials.
- Average production of 55,932 boe/d as compared to production of 60,336 boe/d in the prior year reflects higher decline rates in 2007 and a reduction in 2008 capital spending.
- Operating costs of $300.9 million were unchanged from the prior year, representing $14.70/boe in the current year as compared to $13.66/boe in the prior year.
- Operating netback of $47.89/boe, representing an $18.00/boe (60%) increase over the prior year, attributed to substantially higher commodity prices.
- Completion of two acquisitions for aggregate cash consideration of $167.6 million, to acquire 2,650 boe/d of production representing an average cost per flowing barrel of approximately $63,000 comprised of 1,645 bbls/d of light oil and 6,200 mcf/d of natural gas, offset by divestments of $46.5 million and 640 boe/d.
- Capital spending of $271.3 million included the drilling of 247 wells (150.3 on a net basis) with a 100% success rate plus $128.8 million in net acquisitions, replaced 2008 production with finding and development costs, including changes in future development costs, of $25.97 per boe of proved reserves and $29.87 per boe for proved plus probable reserves.

Summary of Financial and Operating Results

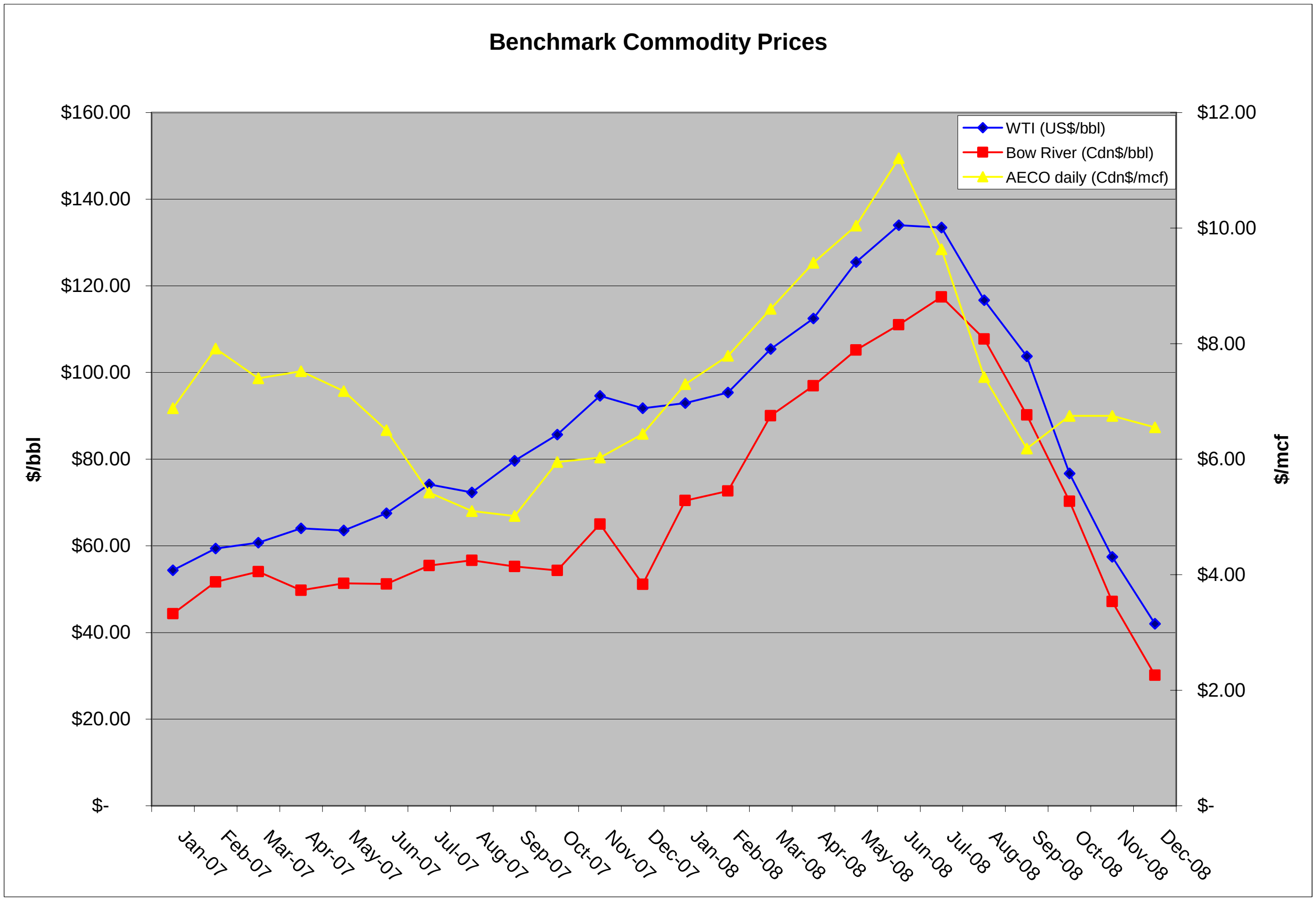
(in $000s except where noted)	Year Ended December 31 **2008**	2007	Change
Revenues	**1,543,214**	1,184,457	30%
Royalties	**(248,445)**	(213,413)	16%
Net revenues	**1,294,769**	971,044	33%
Operating expenses	**300,890**	300,918	0%
General and administrative	**32,868**	34,615	(5%)
Transportation and marketing	**13,490**	11,946	13%
Depreciation, depletion, amortization and accretion	**448,735**	454,142	(1%)
Earnings From Operations(1)	**498,786**	169,423	194%
Cash capital expenditures (excluding acquisitions)	**271,312**	300,674	(10%)
Property and business acquisitions, net of dispositions	**128,773**	138,158	(7%)
Daily sales volumes			
Light to medium oil (bbl/d)	**25,093**	27,165	(8%)
Heavy oil (bbl/d)	**12,162**	14,469	(16%)
Natural gas liquids (bbl/d)	**2,624**	2,412	9%
Natural gas (mcf/d)	**96,315**	97,744	(1%)
Total (boe/d)	**55,932**	60,336	(7%)

(1) This is a non-GAAP measure; please refer to "Non-GAAP Measures" in this MD&A.

Commodity Price Environment

Benchmarks	Year Ended December 31 **2008**	2007	Change
West Texas Intermediate crude oil (US$ per barrel)	**99.65**	72.31	38%
Edmonton light crude oil ($ per barrel)	**102.02**	76.25	34%
Bow River blend crude oil ($ per barrel)	**84.10**	53.36	58%
AECO natural gas daily ($ per mcf)	**8.14**	6.45	26%
Canadian / U.S. dollar exchange rate	**0.943**	0.935	1%

The following graph summarizes benchmark commodity prices for our upstream production for the period of January 2007 to December 2008:



During 2008, the average WTI benchmark price was 38% higher than the prior year. The average Edmonton light crude oil price ("Edmonton Par") also increased from the prior year to average $102.02 in 2008, an increase of 34%. The increase in Edmonton Par has been less than the increase in WTI due to weaker demand for light crude oil in western Canada as a result of refineries converting to heavier crude blends coupled with the modest strengthening of the Canadian dollar relative to the U.S. dollar in 2008.

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. During 2008, the Bow River heavy oil differential relative to Edmonton Par tightened to an average of $17.92/bbl (or 17.6%) compared to $22.89/bbl (or 30.0%) in 2007. On a per barrel basis, heavy oil differentials tightened throughout the year as production shortfalls and increased refinery demand for heavier grades of oil put upward pressure on pricing.

	2008				2007			
Differential Benchmarks	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Bow River Blend differential to Edmonton Par ($/bbl)	**14.07**	**16.48**	**21.50**	**19.63**	29.51	23.87	21.12	17.06
Bow River Blend differential as a % of Edmonton Par	**22.2%**	**13.5%**	**17.1%**	**20.2%**	34.2%	30.0%	29.4%	25.4%

Compared to the prior year, the average AECO daily natural gas price was 26% higher during the year ended December 31, 2008. Natural gas prices have strengthened in 2008 relative to 2007 due to a general strengthening of commodity prices.

Realized Commodity Prices[1]

The following table summarizes our average realized price by product for 2008 and 2007.

	Year Ended December 31		
	2008	2007	Change
Light to medium oil ($/bbl)	**89.72**	64.09	40%
Heavy oil ($/bbl)	**77.22**	46.71	65%
Natural gas liquids ($/bbl)	**75.16**	62.26	21%
Natural gas ($/mcf)	**8.60**	6.94	24%
Average realized price ($/boe)	**75.39**	53.78	40%

[1] Realized commodity prices exclude the impact of price risk management activities.

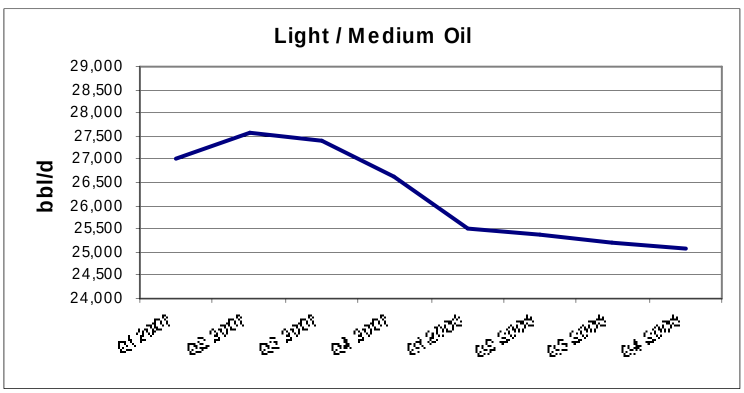
Our realized price for light to medium oil sales increased by $25.63/bbl (or 40%) compared to the prior year, reflecting the $25.77/bbl (or 34%) increase in Edmonton Par pricing. Harvest's heavy oil price increased by $30.51/bbl (or 65%) compared to the prior year, reflecting the $30.74/bbl (or 58%) increase in the Bow River price. Our average realized price for our natural gas production increased by $1.66/mcf (or 24%) compared to the prior year, reflecting the $1.69/mcf (or 26%) increase in AECO daily pricing over the year.

Sales Volumes

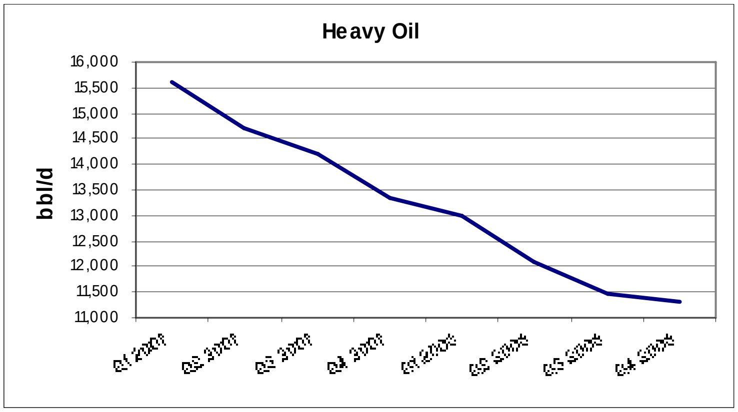
The average daily sales volumes by product were as follows:

	Year Ended December 31				
	2008		2007		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)[1]	**25,093**	**45%**	27,165	45%	(8%)
Heavy oil (bbl/d)	**12,162**	**22%**	14,469	24%	(16%)
Natural gas liquids (bbl/d)	**2,624**	**5%**	2,412	4%	9%
Total liquids (bbl/d)	**39,879**	**72%**	44,046	73%	(9%)
Natural gas (mcf/d)	**96,315**	**28%**	97,744	27%	(1%)
Total oil equivalent (boe/d)	**55,932**	**100%**	60,336	100%	(7%)

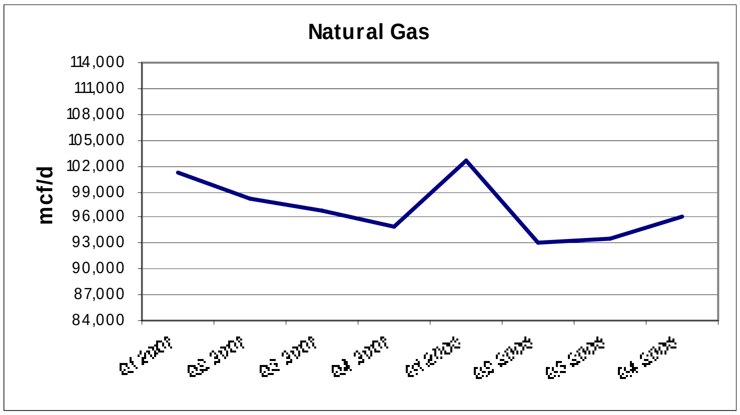
[1] Harvest classifies our oil production, except that produced from Hay River, as light to medium and heavy according to NI 51-101 guidance. The oil produced from Hay River has an average API of 24° (medium grade) and is classified as a light to medium oil, notwithstanding that, it benefits from a heavy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



Harvest's average daily production of light/medium oil in 2008 was 25,093 bbl/d, a 2,072 bbl/d or 8% reduction from the prior year. The 8% reduction is mainly attributed to a lower lever of drilling activity in 2008 and the initial flush production from wells completed in early 2007 stabilized at lower rates by the end of 2007. Light/medium production in 2008 has continued to remain relatively consistent as compared to the 2007 exit rate of production as increased water cuts and production lost to downtime have been substantially offset by new wells drilled in 2008 and the production from acquisitions completed during the Third Quarter. Production at our largest area, Hay River, has remained constant over the past year reflecting our increased water injection in early 2008 which improved recovery.



Our heavy oil production has decreased steadily over the past twelve months resulting in a 16% reduction with year-to-date production of 12,162 bbl/d as compared to 14,469 bbl/d in 2007. This reduction is largely the result of cold and wet weather related operational problems in the first half of 2008. Additionally, increased water cuts on our larger producing wells in the west central Saskatchewan and Lloydminster areas were only partially offset by new wells drilled in the year.



Our 2008 natural gas production decreased by 1% relative to 2007, averaging 96,315 mcf/d. Harvest's 2008 average daily production is lower than in 2007 due to continued declines and production disruptions throughout the Fourth Quarter of 2007 and Second Quarter 2008 offset by incremental production resulting from our 2008 winter drilling program, acquisitions completed in the Third Quarter of 2008, and improved run time on our largest producing wells in the Fourth Quarter of 2008.

Revenues

	Year Ended December 31		
(000s)	**2008**	2007	Change
Light to medium oil sales	**$ 824,014**	$ 635,470	30%
Heavy oil sales	**343,717**	246,674	39%
Natural gas sales	**303,303**	247,499	23%
Natural gas liquids sales and other	**72,180**	54,808	32%
Total sales revenue	**1,543,214**	1,184,451	30%
Royalties	**(248,445)**	(213,413)	16%
Net Revenues	**$ 1,294,769**	$ 971,038	33%

Our revenue is impacted by changes to production volumes, commodity prices and currency exchange rates. Our 2008 total sales revenue of $1,543.2 million is $358.8 million higher than the prior year, of which $442.4 million is attributed to higher realized prices offset by a $83.6 million negative variance in respect of lower production volumes. The price increase reflects the 34% increase in Edmonton Par pricing and the 26% increase in AECO daily natural gas pricing in 2008 as compared to 2007, while our decreased production volume is attributed to decline rates, particularly in 2007, and a reduction in 2008 capital spending.

As discussed earlier, light to medium oil sales revenue for 2008 was $188.5 million higher than the prior year due to a $235.4 million favourable price variance offset by a $46.9 million unfavourable volume variance. Heavy oil sales revenue of $343.7 million in 2008 was $97.0 million higher than in the prior year due to a $135.8 million favourable price variance offset by a $38.8 million unfavourable volume variance. Natural gas sales revenue increased by $55.8 million in 2008 compared to 2007 due to a $58.8 million favourable price variance offset by a $3.0 million unfavourable volume variance.

During 2008, natural gas liquids and other sales revenue increased by $17.4 million compared to the prior year resulting from a $12.4 million favourable price variance and a $5.0 million favourable volume variance. Generally, the natural gas liquids volume variance will be aligned with our production of natural gas while the price variances will be aligned with the prices realized for our oil production. The positive volume variance is attributed to a few natural gas wells drilled near the end of 2007 and throughout 2008, which yielded significant natural gas liquids.

Royalties

We pay 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.

Throughout 2008, net royalties as a percentage of gross revenue were 16.1% (2007 - 18.0%) and aggregated to $248.4 million (2007 - $213.4 million). Our royalty rate for the year was slightly lower than the expected rate of 17% due to various credits received throughout the year.

Operating Expenses

	Year Ended December 31				
	2008		2007		Per BOE
(000s except per boe amounts)	**Total**	**Per BOE**	Total	Per BOE	Change
Operating expense					
Power and fuel	**$ 80,162**	**$ 3.92**	$ 64,053	$ 2.91	35%
Well Servicing	**52,561**	**2.57**	59,500	2.70	(5%)
Repairs and maintenance	**51,462**	**2.51**	50,244	2.28	10%
Lease rentals and property taxes	**27,953**	**1.37**	23,803	1.08	27%
Processing and other fees	**15,073**	**0.74**	17,556	0.80	(8%)
Labour – internal	**23,785**	**1.16**	22,757	1.03	13%
Labour – contract	**17,128**	**0.84**	15,511	0.70	20%
Chemicals	**15,968**	**0.78**	14,910	0.68	15%
Trucking	**11,297**	**0.55**	11,833	0.54	2%
Other	**5,501**	**0.26**	20,751	0.94	(72%)
Total operating expense	**$ 300,890**	**$ 14.70**	$ 300,918	$ 13.66	8%
Transportation and marketing expense	**$ 13,490**	**$ 0.66**	$ 11,946	$ 0.54	22%

Our 2008 operating costs totaled $300.9 million, unchanged from 2007. On a per barrel basis, operating costs have increased to $14.70/boe as compared to $13.66/boe in the prior year, an 8% increase substantially attributed to reduced production volumes. The largest components of operating expense are power and fuel costs, well servicing, and repairs and maintenance costs. Well servicing and repairs and maintenance costs continue to reflect the high demand for oilfield services, although with reduced activity compared to the prior year, these costs have remained relatively stable.

Power and fuel costs, comprised primarily of electric power costs, represented approximately 27% of our total operating costs during 2008. The average Alberta electric power price of $89.95/MWh in the year was 35% higher than the average 2007 price of $66.84/MWh and this increase is reflected in our 35% per boe increase in power and fuel costs compared to the prior year. To mitigate our exposure to electric power price fluctuations we had electric power price risk management contracts in place which resulted in a gain of $10.0 million compared to a gain of $3.1 million in the prior year. The risk management contracts for electric power costs ended in December 2008 and accordingly our electricity usage in Alberta will be exposed to market prices beginning January 1, 2009. The following table details the electric power costs per boe before and after the impact of our price risk management program.

	Year Ended December 31		
(per boe)	**2008**	2007	Change
Electric power and fuel costs	**$ 3.92**	$ 2.91	35%
Realized gains on electricity risk management contracts	**(0.49)**	(0.14)	250%
Net electric power and fuel costs	**$ 3.43**	$ 2.77	24%
Alberta Power Pool electricity price (per MWh)	**$ 89.95**	$ 66.84	35%

Transportation and marketing expense for 2008 was $13.5 million or $0.66/boe, an increase of 22% per boe from $11.9 million or $0.54 per boe in 2007. These costs relate primarily to delivery of natural gas to Alberta's natural gas sales hub, the AECO Storage Hub, and to a lesser extent, our costs of trucking clean crude oil to pipeline receipt points. As a result, the total dollar amount of costs fluctuates in relation with our natural gas production volumes while the cost per boe typically remains relatively constant. The increased transportation and marketing expense in 2008 is primarily due to increased clean oil trucking costs associated with the two acquisitions completed in the Third Quarter.

Operating Netback

	Year Ended December 31	
(per boe)	**2008**	2007
Revenues	**$ 75.39**	$ 53.78
Royalties	**(12.14)**	(9.69)
Operating expense	**(14.70)**	(13.66)
Transportation and marketing expense	**(0.66)**	(0.54)
Operating netback[1]	**$ 47.89**	$ 29.89

[1] This is a non-GAAP measure; please refer to "Non-GAAP Measures" in this MD&A.

Harvest's operating netback represents the net amount realized on a per boe basis after deducting directly related costs. In 2008, our operating netback increased by $18.00/boe or 60% over the prior year. The increase in our operating netback is primarily attributed to a $21.61/boe increase in realized commodity prices, reflecting the increase in Edmonton Par, Bow River and AECO pricing over the prior year, offset by an increase in royalties of $2.45/boe resulting from higher realized prices.

General and Administrative ("G&A") Expense

	Year Ended December 31		
(000s except per boe)	**2008**	2007	Change
Cash G&A	**$ 33,643**	$ 31,892	5%
Unit based compensation expense (recovery)	**(775)**	2,723	(128%)
Total G&A	**$ 32,868**	$ 34,615	(5%)
Cash G&A per boe ($/boe)	**$ 1.64**	$ 1.45	13%

For the year ended December 31, 2008, Cash G&A costs increased by $1.8 million (or 5%) compared to the prior year, reflecting higher employee costs in a continued tight market for technically qualified staff in the western Canadian petroleum and natural gas industry. Generally, approximately 75% of our Cash G&A expenses are related to salaries and other employee related costs.

Our unit based compensation plans provide employees with the option of settling outstanding awards with cash. As a result, unit based compensation expense is determined using the intrinsic method, being the difference between the Trust Unit trading price and the strike price of the unit awards adjusted for the proportion that is vested. The market price of our Trust Units was $20.63 at December 31, 2007 and on December 31, 2008, the price was $10.50. Total unit based compensation expense decreased $3.5 million in 2008 compared to 2007 as the market price of Harvest Trust Units decreased by $10.13 per Trust Unit in 2008 which was greater than the $5.60 per Trust Unit decrease in 2007.

Depletion, Depreciation, Amortization and Accretion Expense

	Year Ended December 31		
(000s except per boe)	**2008**	2007	Change
Depletion, depreciation and amortization	**$ 414,969**	$ 420,184	(1%)
Depletion of capitalized asset retirement costs	**15,135**	15,621	(3%)
Accretion on asset retirement obligation	**18,631**	18,337	2%
Total depletion, depreciation, amortization and accretion	**$ 448,735**	$ 454,142	(1%)
Per boe	**$ 21.92**	$ 20.62	6%

Our overall depletion, depreciation, amortization and accretion ("DDA&A") expense for the year ended December 31, 2008 was $5.4 million lower compared to the prior year. The decrease is attributed to lower production volumes partially offset by slightly higher finding, development and acquisition costs that have increased our depletion rate compared to the same periods of the prior year.

Capital Expenditures

	Year Ended December 31	
(000s)	**2008**	2007
Land and undeveloped lease rentals	**$ 7,762**	$ 2,785
Geological and geophysical	**6,782**	6,058
Drilling and completion	**164,628**	146,941
Well equipment, pipelines and facilities	**81,680**	134,423
Capitalized G&A expenses	**10,235**	8,353
Furniture, leaseholds and office equipment	**225**	2,114
Development capital expenditures excluding acquisitions and non-cash items	**271,312**	300,674
Non-cash capital additions (recoveries)	**(251)**	371
Total development capital expenditures excluding acquisitions	**$ 271,061**	$ 301,045

In 2008, approximately 61% of our development capital expenditures were incurred to drill 247 gross wells with a success rate of 100%, compared to 182 gross wells with a success rate of 98% in 2007. While we continued to focus our drilling activity on oil opportunities (68% of net wells drilled) given the strong oil price environment through most of the year, our natural gas drilling in central Alberta resulted in some particularly successful wells. At Chedderville, we benefited from our 2006 exploration discovery with the drilling of 3 additional wells into this prolific Mannville channel. Additional pipeline infrastructure was completed by the end of the year and the wells were brought on stream bringing our production from this once undeveloped area to approximately 1,800 boe/d.

Over 80% of our 2008 drilling activity focused on our Markerville, Lloydminster/Hayter, southeast Saskatchewan, southeast Alberta and Rimbey properties. In Markerville we drilled 63 gross wells focusing on infill opportunities in our Edmonton sands shallow gas play as well as deeper targets in the Ostracod and Ellerslie channel systems. At Lloydminster/Hayter, we drilled 34 gross wells, primarily horizontal wells targeting infill locations in both the Lloydminster and Dina sandstone formations. In southeast Saskatchewan, we drilled 45 gross horizontal wells pursuing light oil accumulations in both the Souris Valley and Tilston formations with a 100% success rate. A horizontal test well into the Bakken formation provided us with information to further assess the Bakken potential on Harvest's Bakken rights of approximately 12,000 net acres. In southeast Alberta, we drilled 40 gross wells including the transferring of our horizontal well experience in Lloydminster to the development of a new heavy oil play in the Sunburst sandstone formation at Murray Lake where we drilled 4 horizontal wells. At Rimbey, we continued to pursue primarily gas opportunities by drilling 21 gross wells to continue our successful exploration activities pursuing Ostracod channel sands as well as shallow Edmonton sands opportunities.

Our enhanced oil recovery ("EOR") efforts continue. At Hay River, rather than executing a large drilling program, we focused on enhancing our infrastructure and water injection to better manage the performance of our Bluesky reservoir. By increasing injection in early 2008, we were able to maintain our production levels throughout 2008 without drilling any new wells, our December 2008 production was 1,600 boe/d ahead of our original expectations.

At Bellshill Lake, an independent engineering study, as well as field trials, confirmed that increased water injection would reduce our production decline rate and result in an overall improved recovery from this large Ellerslie medium gravity oil pool. In 2008, we completed the installation of a water transfer line from our south Bellshill pool to bring incremental produced water to our main Bellshill Lake pool which has allowed us to further increase the volume of water injection in the Fourth Quarter of 2008.

At Suffield, we launched an enhanced water flood pilot with the installation of a water transfer line from our main Batus facility to our Lark oil pool. Suffield produces heavy gravity oil from Basal Quartz sandstone reservoirs and produced water collected from a number of separate oil pools (including Lark) was not re-distributed to the pools resulting in reduced reservoir pressure as fluids were produced over time. By redistributing water from Batus to the other pools, we will be able to access incremental oil reserves as we "re-charge" the reservoirs. Our main Batus reservoir will also benefit as we will be reducing the amount of "over-injection" which can result in this heavier oil being bypassed in favor of the more mobile water. Injection was initiated in the Third Quarter of 2008.

At Wainwright, we completed the majority of our laboratory testing and completed the acquisition of our polymer injection skid with injection scheduled to begin late in the First Quarter of 2009. The polymer injection represents the first phase of our pilot testing the enhanced recovery impact on this medium gravity Sparky oil pool. We will be initially testing the benefit of polymer injection alone, to be followed up with an Alkaline Surfactant Polymer pilot should the test results be favorable.

The $81.7 million of well equipment, pipelines and facilities expenditures during 2008 includes the equipping of wells drilled during the year, and also a number of infrastructure initiatives to optimize the production performance of our asset base. Approximately $9 million was invested at various properties to ensure the integrity of our transportation and processing infrastructure. At Chedderville, we completed an expansion to our gathering infrastructure for approximately $1 million to allow new wells to be brought on stream, and to fully optimize the production from our original discovery well. At southeast Saskatchewan, we installed a free water knockout vessel at our Kenossee pool for total capital of approximately $1 million to allow production to be optimized from our infill and step out drilling program. Approximately $8 million was part of our EOR implementation at Bellshill Lake, Suffield, Hay River and Wainwright as noted above.

The following summarizes Harvest's participation in gross and net wells drilled during 2008:

	Total Wells		**Successful Wells**		**Abandoned Wells**	
Area	**Gross**[(1)]	**Net**	**Gross**	**Net**	**Gross**	**Net**
Southeast Saskatchewan	45.0	35.5	45.0	35.5	-	-
Southeast Alberta	40.0	15.5	40.0	15.5	-	-
Red Earth	12.0	11.3	12.0	11.3	-	-
Suffield	12.0	12.0	12.0	12.0	-	-
Lloydminster/Hayter	34.0	31.8	34.0	31.8	-	-
Rimbey	21.0	7.3	21.0	7.3	-	-
Markerville	63.0	26.9	63.0	26.9	-	-
Northwest Alberta	10.0	3.8	10.0	3.8	-	-
Other Areas	10.0	6.2	10.0	6.2	-	-
Total	247.0	150.3	247.0	150.3	-	-

(1) Excludes 18 additional wells that we have an overriding royalty interest in.

Our 2008 capital program, along with our acquisitions and divestitures, replaced our production on a proved plus probable basis with 2008 year end reserves of 219.9 million boe, substantially unchanged from 220.9 million boe at the end of 2007. Including changes in future development costs, our 2008 finding and development costs averaged $25.97 per boe of proved reserves while our finding, development and acquisition costs averaged $27.90 per boe of proved reserves as compared to $28.44/boe and $26.98/boe, respectively, in the prior year and a three year average of $27.27/boe and $28.78/boe, respectively. Based on the forecast prices and costs of our independent reservoir engineers as at December 31, 2008, the net present value of our future net revenues from proved reserves using a 10% discount rate is $2,941.8 million and $3,893.8 million from proved plus probable reserves. With 2008 netback price of $47.89/boe in 2008, our finding and development costs result in a recycle ratio of 1.6 while our finding, development and acquisition costs result in a recycle ratio of 1.7. Based on our 2008 production of 20.5 million boe, our 2008 year end proved reserves represent a reserve life index of 7.5 years while our proved plus probable reserves represent a reserve life index of 10.8 years.

Acquisitions and Divestitures

In late July 2008, we acquired a private oil and natural gas company for cash consideration of $36.8 million. The associated production was approximately 390 bbl/d of light oil in an area immediately adjacent to our existing operations in Red Earth plus 2,300 mcf/d of natural gas from a shallow gas play in north central Alberta. An independent engineering report prepared effective April 1, 2008 estimated proved and probable reserves of 1,800 mboe.

In early September 2008, we acquired conventional oil and gas properties in the Peace River Arch area of northern Alberta with approximately 1,900 boe of daily production (66% oil and 24% natural gas) in exchange for cash consideration of $130.8 million plus some minor natural gas interests which produced approximately 85 boe/d during the first half of 2008. During the first half of 2008, the acquired properties averaged production of approximately 1,255 bbl/d of light gravity oil and natural gas liquids plus 3,900 mcf/d of natural gas. An independent engineering report prepared effective December 31, 2007 estimated proved reserves at 7,260 mboe and proved plus probable reserves at 9,899 mboe.

During the Third Quarter, we disposed of various non-operated properties in the Pouce Coupe area in exchange for cash consideration of $36.8 million plus some freehold mineral interests in southeast Saskatchewan. These properties had average daily production of approximately 2,800 mcf/d of natural gas and 14 boe/d of natural gas liquids.

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, 2008, we had $677.6 million of goodwill on our balance sheet related to our upstream segment, of which $0.8 million was added during 2008 with our purchase of a private oil and natural gas company. 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. Although commodity prices decreased significantly in the second half of 2008 no goodwill impairment charges have been made due to the historical cost of the oil assets, which were acquired based on oil prices consistent or lower compared to prices prevalent in the market today.

Asset Retirement Obligation (“ARO”)

In connection with property acquisitions and development expenditures, we record the fair value of the ARO as a liability in the same year the expenditures occur. The associated asset retirement costs are capitalized as part of the carrying amount of the assets and are depleted and depreciated over our estimated net proved reserves. Once the initial ARO is measured, it is adjusted at the end of each period to reflect the passage of time as well as changes in the estimated future cash flows of the underlying obligation. Our asset retirement obligation increased by $63.8 million during 2008 as a result of accretion expense of $18.6 million, new liabilities recorded of $7.2 million, and upward revisions in estimates of $49.4 million, offset by $11.4 million of actual asset retirement expenditures incurred.

DOWNSTREAM OPERATIONS

2008 Highlights

- Cash from downstream operations totaled $83.6 million (2007 - $165.0 million) with sound operating performance more than offset by generally lower refining margins, higher costs for purchased energy and, in the Fourth Quarter, an inventory write-down due to significantly lower commodity prices.
- An average refining margin of US$7.16/bbl reflects a US$2.89 decrease over the prior year primarily attributed to lower margins on gasoline and high sulphur fuel oil ("HSFO") products partially offset by improved margins on distillate products and higher discounts on feedstock, all relative to the WTI benchmark price.
- Refinery throughput averaged 103,497 bbls/d, representing a 90% utilization rate, with throughput limited from May through August in an effort to optimize refining margins by minimizing the production of HSFO and from September through December due to fouling of heat exchangers.
- Refining operating costs of $2.08/bbl of throughput as compared to $2.33/bbl in the prior year reflects increased throughput and cost containment efforts resulting in a relatively stable level of spending at $78.9 million.
- Cost of purchased energy increased to $3.48/bbl of throughput as compared to $2.57/bbl in the prior year reflecting a significantly higher commodity price environment during the first three quarters of 2008, while turnaround and catalyst costs reflect a modest visbreaker turnaround in 2008 as compared to an extensive shutdown in 2007.
- Capital spending totaled $56.2 million as compared to $44.1 million in the prior year with $30.1 million incurred for the visbreaker expansion project commissioned in November 2008.

Summary of Financial and Operational Results

	Year Ended December 31		
(in $000's except where noted below)	**2008**	2007	Change
Revenues	**4,194,595**	3,098,556	35%
Purchased feedstock for processing and products purchased for resale[4]	**3,850,507**	2,667,714	44%
Gross margin[1]	**344,088**	430,842	(20%)
Costs and expenses			
Operating expense	**98,736**	102,476	(4%)
Purchased energy expense	**131,878**	92,328	43%
Turnaround and catalyst expense	**5,645**	34,486	(84%)
Marketing expense and other	**20,753**	34,970	(41%)
General and administrative expense	**1,875**	1,713	9%
Depreciation and amortization expense	**71,076**	72,600	(2%)
Earnings From Operations[1]	**14,125**	92,269	(85%)
Cash capital expenditures	**56,162**	44,111	27%
Feedstock volume (bbl/day)[2]	**103,497**	98,617	5%
Yield (000's barrels)			
Gasoline and related products	**12,068**	11,515	5%
Ultra low sulphur diesel and jet fuel	**15,668**	14,406	9%
High sulphur fuel oil	**9,952**	9,843	1%
Total	**37,688**	35,764	5%
Average refining margin (US$/bbl)[3]	**7.16**	10.05	(29%)

[1] These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.
[2] Barrels per day are calculated using total barrels of crude oil feedstock and vacuum gas oil.
[3] Average refining margin is calculated based on per barrel of feedstock throughput.
[4] Purchased feedstock for processing and products purchased for resale includes inventory write-downs of $35.3 million in the Fourth Quarter of 2008.

Overview of Downstream Operations

Our downstream operations are comprised of an 115,000 bbls/d medium gravity sour crude oil hydrocracking refinery and a retail and wholesale petroleum marketing business both located in the Province of Newfoundland and Labrador. Our petroleum marketing business is comprised of the retail and wholesale distribution of gasoline, diesel, jet and other transportation fuels as well as home heating fuels and related appliances and the revenues from our marine services including tugboat revenues.

The financial performance of our refinery reflects its throughput, feedstock selection, operating effectiveness, refining margins and operating costs. Our refining margin is dependent on the sales value of the refined products produced and the cost of crude oil feedstock purchased as well as the yield of refined products from various crude oil feedstocks. We continuously evaluate the market and relative refinery values of several different crude oils and vacuum gas oils to determine the optimal feedstock mix. We analyze our refining margin on each refined product and our sales revenue relative to benchmark prices for the refined product and the WTI benchmark price. With respect to feedstock costs, we analyze our price discounts relative to the WTI benchmark price and segregate crude oil sources by country of origin.

We purchase substantially all of our refinery feedstock and sell our distillate and gasoline products, with the exception of products sold in Newfoundland through our petroleum marketing division, to Vitol Refining S.A. ("Vitol") pursuant to the Supply and Offtake Agreement. Effective January 20, 2008, our HSFO is sold to a wholly-owned affiliate of one of the world's largest integrated energy companies; prior to this, our HSFO had been sold to Vitol. During the year ended December 31, 2008, approximately 67% of our refined product sales were to Vitol.

The Supply and Offtake Agreement with Vitol contains pricing terms that reflect market prices based on an average ten day delay which results in our purchases from and sales to Vitol being priced on future prices as compared to pricing at the time of delivery. With the exception of the sales to Vitol, our refined products are sold at prices that reflect market prices at the time that the product is delivered to the purchaser. For more information on the Supply and Offtake Agreement with Vitol, see the description in our Annual Information Form for the year ended December 31, 2007 as filed on SEDAR at www.sedar.com.

For the year ended December 31, 2008, our refining gross margin was $287.6 million as compared to $386.7 million in the prior year, a decrease of $99.1 million. The decrease in refining gross margin is primarily due to weaker gasoline and HSFO margins which resulted in negative price variances of $224.9 million and $66.5 million, respectively, partially offset by improved distillate margins and improved discounts to WTI on our feedstock which resulted in positive price variances of $92.3 million and $121.7 million, respectively.

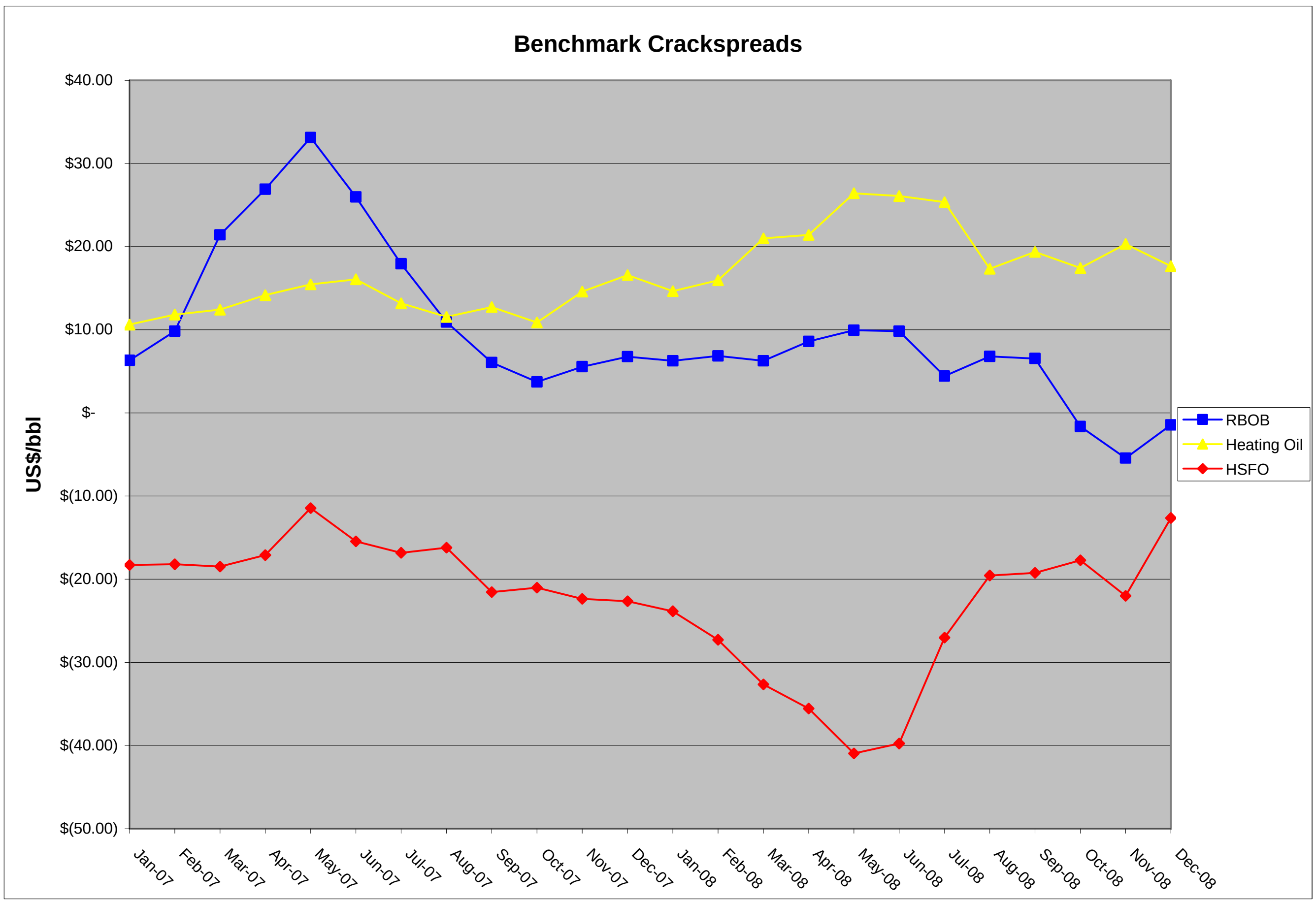
For the year ended December 31, 2008, our marketing division earned a gross margin of $56.5 million as compared to $44.1 million in the prior year, an increase of 28% primarily due to a significant increase in the price of sulphur, which is sold through a profit sharing agreement with a third party processor and contributed $8.5 million in 2008 as compared to $0.3 in 2007.

Refining Benchmark Prices

The following average benchmark prices and currency exchange rates are the reference points from which we discuss our refinery's financial performance:

	Year Ended December 31		
	2008	**2007**	**Change**
WTI crude oil (US$/bbl)	**99.65**	72.31	38%
Brent crude oil (US$/bbl)	**98.38**	72.67	35%
Basrah Official Sales Price Discount (US$/bbl)	**(7.40)**	(6.84)	8%
RBOB gasoline (US$/bbl/gallon)	**104.40/2.49**	86.86/2.07	20%
Heating Oil (US$/bbl/gallon)	**119.89/2.85**	85.65/2.04	40%
High Sulphur Fuel Oil (US$/bbl)	**73.13**	54.02	35%
Canadian / U.S. dollar exchange rate	**0.943**	0.935	1%

The following graph summarizes the crack spreads between the respective benchmark prices for refined products and WTI for the period of January 2007 to December 2008:



During 2008, the Heating Oil Crack Spread averaged US$20.24/bbl, an increase of US$6.90/bbl over the US$13.34/bbl averaged in the prior year, as strong demand for distillate products in North America, Europe and Asia improved margins. The RBOB Gasoline Crack Spread averaged US$4.75/bbl in 2008, a drop of US$9.80/bbl from the US$14.55/bbl averaged in the prior year, as North American demand for gasoline continued to weaken subsequent to June 2007 due to slowing economic activity and consumer response to the record setting prices for gasoline in the summer of 2008. Similarly, the HSFO Crack Spread differential averaged US$26.52/bbl less than WTI in 2008, an increase of US$8.23/bbl from the average differential of US$18.29/bbl less than WTI in the prior year, as margins in the Second Quarter of 2008 were particularly weak.

During 2008, the Canadian/U.S. dollar exchange rate averaged 0.943, an increase of 0.008 from the prior year. The relative strength of the Canadian dollar resulted in a nominal decrease in our cash flows from downstream operations in 2008, as refined product and crude oil prices are denominated in U.S. dollars.

Summary of Gross Margin

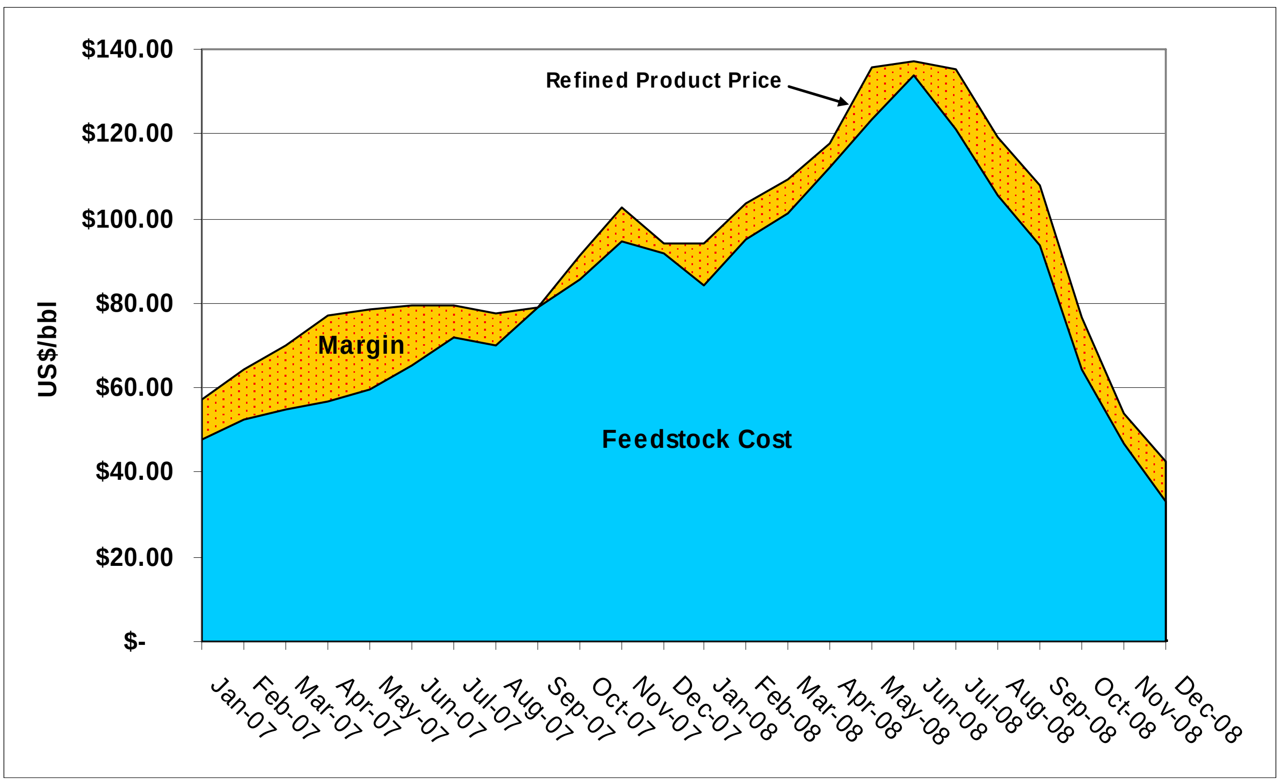
The following table summarizes our downstream gross margin for the years ended December 31, 2008 and 2007 segregated between refining activities and petroleum marketing and other related businesses.

	Year Ended December 31					
	2008			2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Sales revenue[1]	**4,092,555**	**670,686**	**4,194,595**	2,982,655	504,375	3,098,556
Cost of feedstock for processing and products for resale[1]	**3,804,952**	**614,201**	**3,850,507**	2,595,907	460,281	2,667,714
Gross margin[2]	**287,603**	**56,485**	**344,088**	386,748	44,094	430,842
Average refining margin (US$/bbl)	**7.16**			10.05		

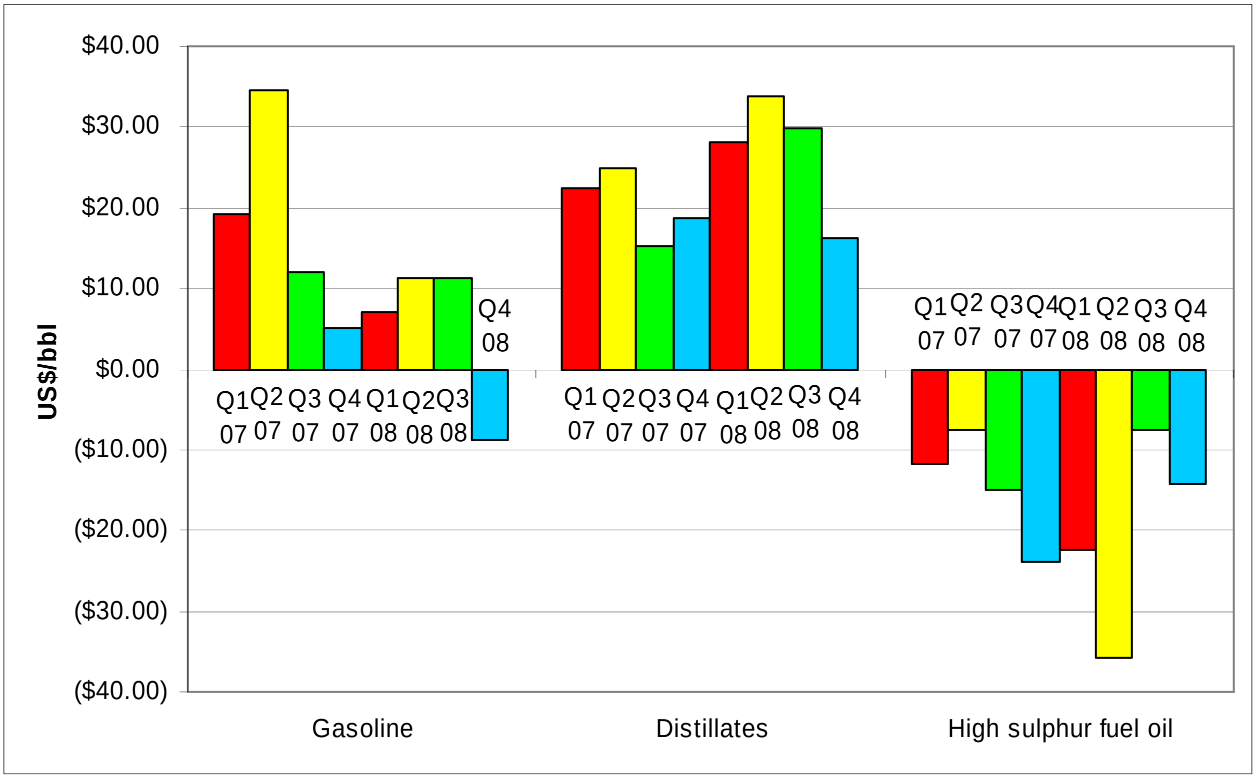
[1] Downstream sales revenue and cost of products for processing and resale are net of intra-segment sales of $568.6 million for the year ended December 31, 2008 (2007 - $388.5 million) reflecting the refined products produced by the refinery and sold by the Marketing Division.
[2] This is a non-GAAP measure; please refer to "Non-GAAP Measures" in this MD&A.

Refining Gross Margin

The following graph summarizes our average refining margin relative to the cost of feedstock for the period of January 2007 to December 2008:



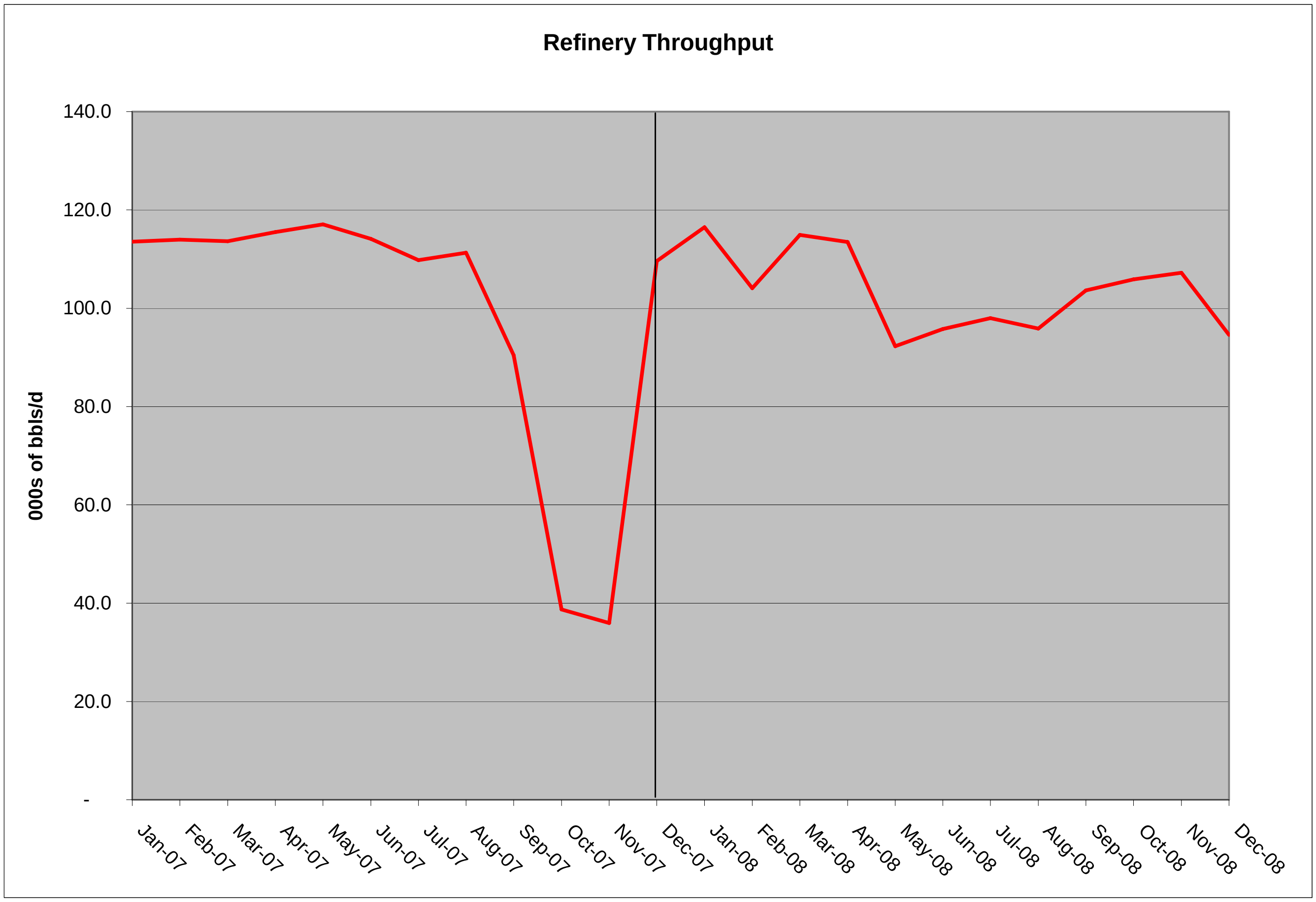
The following chart summarizes our refining margin by refined product over the same time period by quarter:



Crack spreads on gasoline and HSFO peaked during the first half of 2007, resulting in an average refining margin of US$13.69 per bbl with the distillate refining margin averaging US$23.52 per bbl. However, during the second half of 2007 and the first half of 2008 as feedstock costs continued to rise, crack spreads on gasoline and HSFO declined considerably from their peak, and were only partially offset by improved crack spreads on distillate products, which resulted in our average refining margin dropping to US$4.16 per bbl and US$7.36 per bbl for the six month periods ended December 31, 2007 and June 30, 2008, respectively. During the second half of 2008, although feedstock costs decreased significantly, crack spreads on gasoline continued to deteriorate, particularly in the Fourth Quarter when gasoline crack spreads were negative, resulting in an average refining margin of US$6.95 per bbl.

Refinery Throughput

The throughput of our refinery for the period of January 2007 to December 2008 is illustrated below in thousands of barrels of feedstock per day:



During 2008, our feedstock was comprised of 93,697 bbl/d of medium sour crude oil and 9,800 bbl/d of vacuum gas oil ("VGO") as compared to 87,060 bbl/d of crude oil and 11,557 bbl/d of VGO in the prior year. Our aggregate total throughput in 2008 was 103,497 bbls/d, a 4,880 bbls/d increase over the prior year reflecting a utilization rate of 90% relative to an 115,000 bbls/d nameplate capacity. While the refinery experienced limited planned or unplanned downtime in 2008, our throughput was intentionally reduced from May through August in an effort to improve overall gross margin by reducing feedstock to eliminate the production of vacuum tower bottoms ("VTB's") in excess of our visbreaker unit capacity, thereby eliminating the need to downgrade middle distillate valued streams to blend the excess VTB's into lower valued HSFO. Throughput during September through December was reduced due to fouling in heat exchangers, including an online partial exchanger cleaning in December. The remaining exchangers will be cleaned during the ISOMAX catalysts replacement planned for April 2009. During the Fourth Quarter of 2007, we completed a turnaround of the crude unit and vacuum tower and positioned the refinery for uninterrupted operations in 2008 except for the visbreaker turnaround in the Fourth Quarter of 2008.

Refinery Sales Revenue

A comparison of our refinery yield, product pricing and revenue for the years ended December 31, 2008 and 2007 is presented below:

	Year Ended December 31					
	2008			2007		
	Refinery Revenues	**Volume**	**Sales Price**(1)	Refinery Revenues	Volume	Sales Price(1)
	(000's of Cdn $)	(000s of bbls)	(US$ per bbl/ US$ per US gal)	(000's of Cdn $)	(000s of bbls)	(US$ per bbl/ US$ per US gal)
Gasoline products	**1,327,599**	**12,830**	**97.58/2.32**	1,088,215	11,726	86.77/2.07
Distillates	**2,006,406**	**15,661**	**120.81/2.88**	1,339,388	14,245	87.91/2.09
High sulphur fuel oil	**758,550**	**9,651**	**74.12**	555,052	9,740	53.28
	4,092,555	**38,142**	**101.18**	2,982,655	35,711	78.09
Inventory adjustment		**(454)**			53	
Total production		**37,688**			35,764	
Yield (as a % of Feedstock) (2)		**100%**			99%	

(1) Average product sales prices are based on the deliveries at our refinery loading facilities.

(2) After adjusting for changes in inventory held for resale.

Our refinery sales revenue is dependent on the selling price of the refined products produced as well as the yield of refined products produced from the crude oil and other feedstocks. Although our yield can be altered slightly by adjusting refinery operations to react to market conditions and seasonal demand, product yields are primarily impacted by the type of crude oil feedstock processed and refinery performance. For the year ended December 31, 2008, our refinery yield was comprised of 32% gasoline products, 42% distillates and 26% HSFO compared to 32%, 40% and 28% for the same products respectively during 2007. The shift in product yield in 2008 from HSFO to distillates is primarily attributed to feedstock selection, process unit optimization and reduced throughput.

Our average sales price for our refined products relative to the average WTI price in the current year was US$4.25/bbl lower than in the prior year. In 2008, our average sales price was US$101.18/bbl (a premium of US$1.53/bbl over WTI) as compared to an average selling price of US$78.09/bbl in the prior year (a premium of US$5.78bbl over WTI). This reduction in premium represents a $171.9 million price variance in 2008.

During 2008, the average sales price of our gasoline products of US$97.58/bbl was a US$2.07/bbl discount to the average WTI price as compared to a US$14.46/bbl premium over WTI realized in 2007 representing a $224.9 million decrease in gross margin as compared to the prior year. This US$16.53 drop in our gasoline refining margin relative to WTI reflects generally weaker demand for gasoline in North America.

During 2008, the average sales price for our distillate products of US$120.81/bbl was a US$21.16/bbl premium over the average WTI price as compared to a US$15.60/bbl premium over WTI realized in 2007 representing a $92.3 million increase in gross margin as compared to the prior year. During 2008, the international demand for distillate products was strong supporting improved distillate margins. During 2008, we received US$7.9 million of incremental revenue from delivering approximately 7.5 million barrels of distillate products to Europe pursuant to our profit sharing arrangement with Vitol.

During 2008, the average sales price of our HSFO of US$74.12/bbl was a US$25.53/bbl discount to average WTI price as compared to a US$19.03/bbl discount in 2007 representing a $66.5 million reduction in gross margin as compared to the prior year. The US$5.56/bbl improvement in our distillate pricing relative to WTI and the shift in product yield from HSFO to distillates was insufficient to fully offset the US$16.53/bbl and US$6.50/bbl margin reductions for gasoline products and HSFO, respectively.

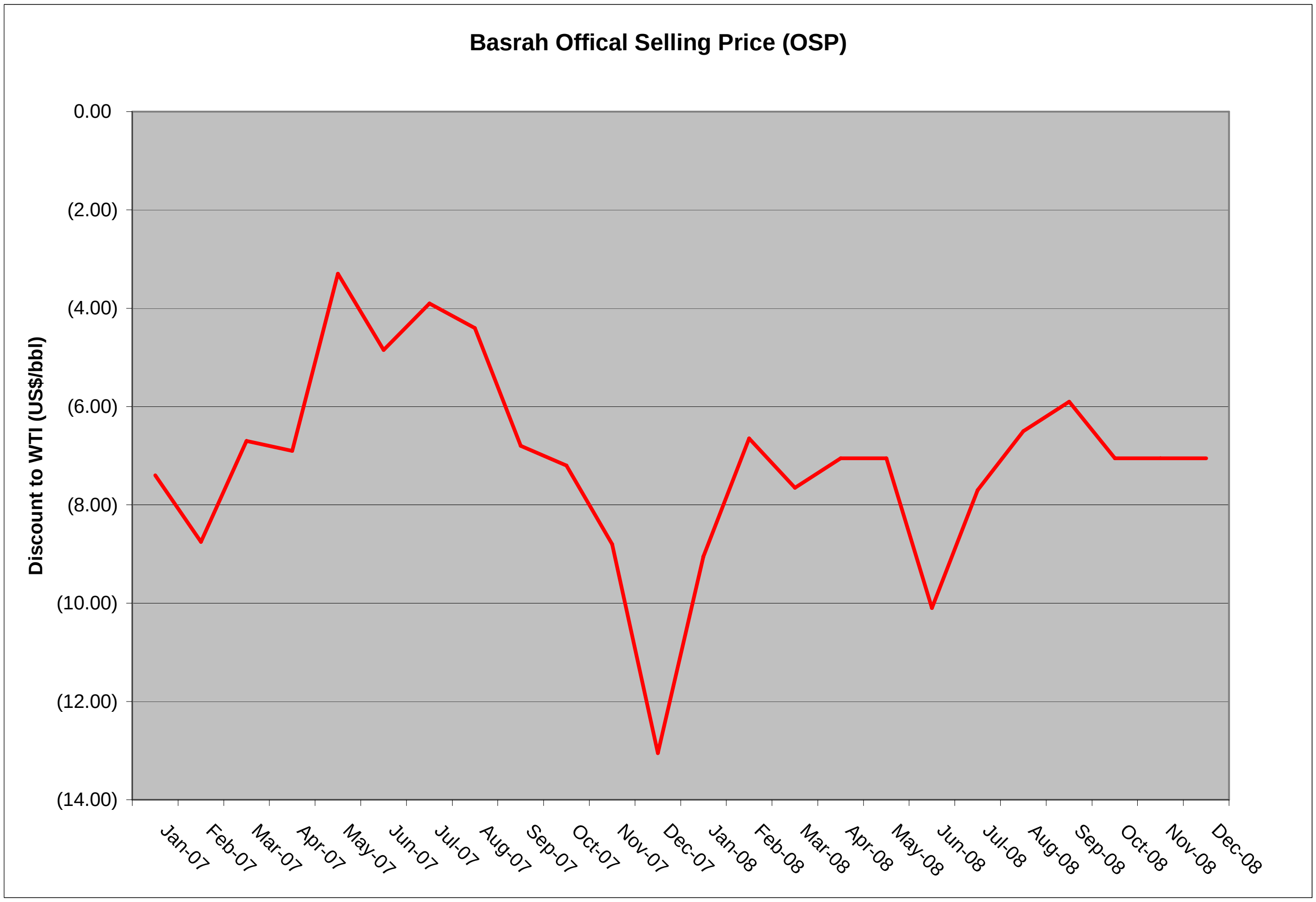
Refinery Feedstock

The volatility of WTI prices throughout 2008 makes it difficult to compare the economics of crude types when our consumption of crude type varies from month to month and costs are aggregated over the year. Further, our refinery competes for international waterborne crude oils and VGOs and the WTI benchmark price generally reflects a land-locked North American price with limited access to the international markets. A comparison of crude oil and VGO feedstock processed for the years ended December 31, 2008 and 2007 is presented below:

	Year Ended December 31					
	2008			2007		
	Cost of Feedstock	**Volume**	**Cost per Barrel** [1]	Cost of Feedstock	Volume	Cost per Barrel [1]
	(000's of Cdn $)	(000s of bbls)	(US$/bbl)	(000's of Cdn $)	(000s of bbls)	(US$/bbl)
Iraqi	**1,963,882**	**21,218**	**87.28**	1,608,356	23,230	64.74
Russian	**614,187**	**5,973**	**96.97**	237,449	3,367	65.94
Venezuelan	**676,777**	**7,102**	**89.86**	362,868	5,180	65.50
Crude Oil Feedstock	**3,254,846**	**34,293**	**89.50**	2,208,673	31,777	64.99
Vacuum Gas Oil	**396,676**	**3,586**	**104.31**	354,858	4,218	78.66
	3,651,522	**37,879**	**90.90**	2,563,531	35,995	66.59
Net inventory adjustment [2]	**(8,990)**			(36,378)		
Additives and blendstocks	**127,136**			68,754		
Inventory write-down [3]	**35,284**			-		
	3,804,952			2,595,907		

[1] Cost of feedstock includes all costs of transporting the crude oil to refinery in Newfoundland.
[2] Inventories are determined using the weighted average cost method.
[3] Inventory write-downs are calculated on a product by product basis using the lower of cost or net realizable value.

Changes to the cost of our feedstock reflect numerous factors beyond changes in WTI price, including the quality of the crude oil processed, the mix of crude oil types, the costs of transporting the crude oil to our refinery, the ten day delay in pricing pursuant to the Supply and Offtake Agreement and for Iraqi crude oil purchased, the Official Selling Price ("OSP") as set by the Oil Marketing Company of the Republic of Iraq. The discount of Iraqi crude oil relative to the WTI benchmark price is influenced by the quality of the crude oil as well as by the demand from other purchasers who may not be North American based. On a monthly basis, the OSP discount is announced as a discount to the WTI benchmark price for North American deliveries. Since our acquisition of North Atlantic in October 2006, the OSP has fluctuated from a low of US$3.30 in May 2007 to a high of US$13.05 in December 2007. The following graph illustrates the volatility of the OSP for Basrah Light since January 2007 which, relative to our US$7.16 average refining margin for 2008, is a significant factor to our downstream financial performance:



Although the OSP discount may change between the date of loading in Iraq and its consumption a few months later at our refinery, the OSP discount applicable at the time of loading does not change for our purchase. For example, the OSP discount of US$7.05 in April 2008 was a component of the cost of our feedstock processed in June and July recognizing the 30 to 45 days required to load in Iraq, in transit time and unloading at our refinery. While we are able to "operationally hedge" the WTI component of our feedstock costs between the date we purchase crude oil and our processing of the crude oil we are not able to hedge or otherwise manage the basis risk associated with the medium sour crude oils we typically process.

The cost of our crude oil feedstock averaged US$89.50/bbl during 2008 representing a US$10.15/bbl discount from WTI as compared to a cost of US$64.99/bbl and a discount of US$7.32/bbl in the prior year. While the increased discount to WTI aggregates to a $102.9 million improved gross margin, the year-over-year US$27.34 increase in the average WTI price added $994.2 million to our crude oil feedstock cost during 2008. The US$89.50/bbl average cost of crude oil feedstock during the year represents a 38% increase over the average cost in the prior year, which impacts Vitol's working capital required and increases our "Time Value of Money" charges paid to Vitol as part of the Supply and Offtake Agreement.

The average cost of purchased VGO during 2008 was US$104.31/bbl representing a premium of US$4.66/bbl relative to the WTI benchmark price as compared to US$78.66/bbl and a US$6.35/bbl premium in the prior year. The higher premium in 2007 is attributed to supply and demand disruptions in that year in the very tightly balanced VGO market. We processed 3.6 million barrels of VGO during the year, as such the US$1.69/bbl lower premium aggregates to a $6.4 million decrease in feedstock costs and a corresponding increase in gross margin compared to 2007.

The benchmark refining crack spreads closely track refining margins if the accounting for feedstock is on a last-in-first-out ("LIFO") basis. Our financial statements account for feedstock on a weighted average cost basis which is in accordance with Canadian generally accepted accounting principles. In a stable commodity price environment, weighted average cost and LIFO accounting results should not be significantly different from market benchmarks and individual refinery results. In a rapidly declining commodity price environment, such as the Fourth Quarter of 2008, the result is that the cost of crude oil feedstock consumed under weighted average cost is higher than on a LIFO basis due to the time lag between crude feedstock purchase and processing. For Harvest, the Supply and Offtake Agreement requires Vitol to hold all crude oil feedstock inventory and substantially all gasoline and distillate inventories and requires Vitol to provide the crude oil feedstock to us at current market prices, resulting in our exposure to falling commodity prices being limited to the inventory we hold, which is primarily work in process material and HSFO inventory. Accordingly, during the Fourth Quarter our refining margins were negatively impacted by write-downs of $35.3 million on our work in progress and HSFO inventories. This write-down is relatively modest compared to the $319.7 million in inventory and in transit commitment held by Vitol to operate our refinery at December 31, 2008, which was a decrease of $540.2 million from the $859.9 million held by Vitol on September 30, 2008.

Operating Expenses

The following summarizes the operating costs from the refinery and marketing division for the years ended December 31, 2008 and 2007:

	Year Ended December 31					
	2008			2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Operating expense	**78,907**	**19,829**	**98,736**	83,935	18,541	102,476
Turnaround and catalyst	**5,645**	**-**	**5,645**	34,486	-	34,486
Purchased energy	**131,878**	**-**	**131,878**	92,328	-	92,328
	216,430	**19,829**	**236,259**	210,749	18,541	229,290

The largest component of refining operating expense is wages, salaries and benefits which totaled $49.6 million during 2008 (2007 - $51.3 million) while the other significant components were maintenance and repair costs of $13.2 million (2007 - $11.9 million), insurance of $5.7 million (2007 - $6.6 million) and professional services of $5.1 million (2007 - $5.7 million). Refining operating expenses were $2.08/bbl during the year as compared to $2.33/bbl in 2007 reflecting increased throughput and a reduction in total refining operating expenses. The marketing division's operating expenses have increased by $1.3 million primarily due to scheduled tug boat maintenance in June 2008.

Turnaround and catalyst expenditures of $5.6 million (2007 - $34.5 million) relate to planned equipment certifications scheduled during the shutdown to implement the visbreaker unit project modifications.

Purchased energy, consisting of low sulphur fuel oil and electricity, is required to provide heat and power to refinery operations. Our purchased energy for the year ended December 31, 2008 was $3.48/bbl of throughput as compared to $2.57/bbl for 2007. In 2008, we purchased approximately 1,599,000 barrels of fuel oil at an average price of US$72.79/bbl as compared to approximately 1,398,000 barrels purchased in 2007 at an average price of US$55.68/bbl. The $39.6 million increase in the cost of purchased fuel oil is due to a $27.3 million increased price variance and an $11.9 million increase in volume consumed. Our electricity costs remained substantially unchanged during the year at $9.9 million as compared to $9.6 million in the prior year.

Marketing Expense and Other

During the year ended December 31, 2008, marketing expense was comprised of $3.4 million (2007 - $3.4 million) of marketing fees (based on US$0.08/bbl) to acquire feedstock and $26.0 million (2007 - $31.6 million) of "Time Value of Money" charges both pursuant to the terms of the Supply and Offtake Agreement. The decreased "Time Value of Money" charge is mainly the result of a lower LIBOR rate in 2008 which was partially offset by a larger crude oil inventory investment due to the higher commodity prices. In the Fourth Quarter of 2008, marketing expense and other includes $8.7 million in one time accrual reversals related to prior periods. As at December 31, 2008, Harvest had commitments totaling approximately $319.7 million in respect of future crude oil feedstock purchases and related transportation from Vitol.

Capital Expenditures

Capital spending for the year ended December 31, 2008 totaled $56.2 million (2007 - $44.1 million). The largest component of our 2008 downstream capital program relates to the expansion and improvement of our visbreaker. The total costs associated with this project were $32.2 million of which approximately $30.1 million was incurred in 2008; the project was completed in mid-November. The increased capacity will upgrade approximately 1,500 bbls/d of HSFO into middle distillate valued streams.

Depreciation and Amortization Expense

The following summarizes the depreciation and amortization expense for the years ended December 31, 2008 and 2007:

	Year Ended December 31					
	2008			2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Tangible assets	**62,383**	**2,555**	**64,938**	64,251	2,071	66,322
Intangible assets	**4,749**	**1,389**	**6,138**	4,781	1,497	6,278
	67,132	**3,944**	**71,076**	69,032	3,568	72,600

The process units are amortized over an average useful life of 20 to 30 years. The intangible assets, consisting of engineering drawings, customer lists and fuel supply contracts, are amortized over a period of 20 years, 10 years and the term of the expected cash flows respectively.

Goodwill

At December 31, 2008, we had $216.2 million of goodwill on our balance sheet related to the October 2006 acquisition of our downstream business segment. As our downstream assets are held in a self-sustaining subsidiary with a U.S. dollar functional currency, our goodwill is adjusted at each balance sheet date to reflect the period end foreign exchange rate. We assess our goodwill for impairment on an annual basis unless events or changes in circumstances warrant more frequent testing. To assess goodwill for potential impairment we compare the estimated fair value of the business segment at the balance sheet date to the recorded net book value. If the estimated fair value exceeds the net book value, no further evaluation is required. Management uses judgment in determining the estimated fair value using internal assumptions and external information to compute the present value of expected future cash flows using discount rates commensurate with the risks involved.

Our fair value estimate at December 31, 2008 assumes the completion of $300 million of planned debottlenecking projects and the related throughput, yield, and energy efficiency improvements. Estimated future refining margins were based on forward curve pricing at December 31, 2008 for the first two years of our projection and were assumed to be constant for subsequent years. Our selected discount rate is based on the long-term risk-free interest rate at December 31, 2008 and adjusted for an appropriate credit spread based on estimated current capital market expectations. We calculated the expected future cash flows for each of the next five years in our fair value model and have computed a terminal value to reflect cash flows to be earned in the years thereafter. At December 31, 2008, the estimated fair value of our downstream business segment exceeded its carrying value, and accordingly, no goodwill impairment was identified.

Related Party Transactions

During the year ended December 31, 2008, Vitol purchased $320.9 million (2007 - $354.8 million) of crude oil pursuant to the terms and conditions of the Supply and Offtake Agreement from a company in which a director of Harvest holds a minority equity interest. On December 21, 2008, the director disposed the interest in the company and as such, subsequent to this date, this company no longer represents a related party.

RISK MANAGEMENT, FINANCING AND OTHER

Cash Flow Risk Management

Harvest employs an integrated approach to cash flow risk management strategies whereby the our cash flow from producing crude oil in western Canada is financially integrated with our requirement to purchase crude oil feedstock for our Downstream operations even though the crude oil produced in western Canada does not physically flow to our refinery in Newfoundland. As a result, our 2009 cash flow at risk is comprised of approximately 33,000 bbls/d of refined product price exposure, 82,000 bbls/d of refined product crack spread exposure and 84,000 mcf/d of western Canadian natural gas price exposure.

Our cash flow risk management program includes a detailed analysis of the impact of changes in crude oil prices, natural gas prices, the U.S./Canadian dollar exchange rate and certain refined product prices. While the strong commodity prices experienced throughout the first three quarters of 2008 resulted in record operating cash flow from our upstream operations, they also resulted in $225.2 million of realized losses on our price risk management contracts. As commodity prices declined in the Fourth Quarter of 2008, we realized $24.4 million of gains on our risk management contracts. The table below provides a summary of the gains and losses realized on our price risk management contracts for the years ended December 31, 2008 and 2007:

	Year Ended December 31		
(000s)	**2008**	2007	Change
Crude oil	**$ (36,625)**	$ (41,462)	(12%)
Refined product	**(174,129)**	-	n/a
Natural gas	**(381)**	6,299	(106%)
Currency exchange rates	**401**	5,725	(93%)
Electric Power	**9,952**	3,147	216%
Total	**$ (200,782)**	$ (26,291)	664%

During 2008, our net realized loss on price risk management contracts increased to $200.8 million, primarily due to the losses on our refined product pricing contracts of $174.1 million, as lower settlements on crude oil and increased gains on electric power contracts were substantially offset by lower gains on our currency exchange and natural gas contracts

With respect to our crude oil production, we had pricing contracts in place for 10,000 bbl/d during the first half of 2008 at an average price of US$60.00/bbl with 73% participation on prices above US$60.00. We had a further 6,000 bbl/d contracted during the second half of 2008, which capped the WTI price at US$87.53 and provided a floor of US$62.00. As WTI averaged US$99.65 in 2008, cash settlements on these crude oil contracts aggregated to $36.6 million, with losses of $41.2 million during the first three quarters, offset by gains of $4.6 million in the Fourth Quarter.

In respect of refined products, we had pricing contracts in place for 12,000 bbl/d of NYMEX heating oil and 8,000 bbl/d of Platts heavy fuel oil throughout 2008. The cash settlements of these contracts aggregated to $128.0 million and $49.3 million, respectively, during the year. In addition, we had contracts in place on 6,000 bbl/d of NYMEX heating oil crack spread, which were settled with cash payments of $12.9 million; 2,000 bbl/d of Platts heavy fuel oil crack spread, which settled with cash received by Harvest of $5.1 million; and 6,000 bbl/d of NYMEX RBOB gasoline crack spread, which were settled with cash received by Harvest of $10.9 million during the year. In total, during the first three quarters of 2008, we realized losses on our refined product contracts totaling $195.7 million, offset by gains of $21.6 million in the Fourth Quarter.

With respect to currency exchange rates, we had contracted to fix the exchange rate during the first six months of 2008 on US$8.3 million per month averaging Cdn$1.11 per US $1.00 and throughout 2008 we had an exchange rate collar in place that collared an exchange rate of Cdn$1.00 to Cdn$1.055 per US$1.00 on a further US$10 million per month. The settlements on the fixed rate contract resulted in $5.2 million received by Harvest during the first six months of 2008 while the exchange rate collar settled with payments of $4.8 million by Harvest.

During 2008, the settlement of our fixed price power contracts for 35 MWh at $56.69 per MWh resulted in $10.0 million received by Harvest as the Alberta electric power prices averaged $89.95 per MWh during the period. The fixed price contract ended in December 2008.

As of December 31, 2008, the mark-to-market value on our refined product contracts was $36.1 million, while the mark-to-market deficiency on our natural gas contracts was $0.2 million. We had no contracts for WTI, currency exchange rate and electrical power at the end of December 2008. Further details on our financial instruments and risk management contracts are included in Note 20 to the audited consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com.

As of December 31, 2008, we had risk management contracts in place for 12,000 bbl/d of NYMEX heating oil and 8,000 bbl/d of Platts heavy fuel oil from January 2009 through June 2009 and a negligible amount of natural gas contracts through to the end of 2009. These contracts are more fully described in the "Outlook" section of this MD&A.

Interest Expense

	Year Ended December 31		
(000s)	**2008**	2007	Change
Interest on short term debt			
Bank loan	**$ -**	$ 1,275	(100%)
Convertible Debentures	**295**	2,498	(88%)
Amortization of deferred finance charges – short term debt	**-**	1,811	(100%)
	295	5,584	(95%)
Interest on long-term debt			
Bank loan	**51,855**	70,204	(26%)
Convertible Debentures	**69,159**	56,740	22%
$7^{7/8}$% Senior Notes	**22,662**	22,561	0%
Amortization of deferred finance charges – long term debt	**2,699**	2,696	0%
	146,375	152,201	(4%)
Total interest expense	**$ 146,670**	$ 157,785	(7%)

Interest expense, including the amortization of related financing costs, decreased $11.1 million (7%) compared to the prior year as interest on our bank borrowings has decreased by $19.6 million due to lower borrowing costs, while total interest expense on Convertible Debentures has increased as a result of our 2008 Convertible Debenture offering.

The interest on our $1.6 billion Extendible Revolving Credit Facility is at a floating rate based on 70 basis points over bankers' acceptances for Canadian dollar borrowings. During the year, interest charges on bank loans reflected an effective interest rate of 4.12%. Further details on our credit facilities are included under "Liquidity and Capital Resources" and Note 10 to the audited consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com.

The interest on our Convertible Debentures totaled $69.5 million during 2008, representing a $10.2 million increase over the prior year. The increase is due to the April 25th issuance of $250 million face value of 7.5% Convertible Debentures due 2015. Details on the Convertible Debentures outstanding are fully described in Note 12 to the audited consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com. Interest on the Convertible Debentures is based on the effective yield of the debt component of the Convertible Debentures, and as a result, the interest expense recorded is greater than the cash interest paid.

The interest on our $7^{7/8}$% Senior Notes totaled $22.7 million for the year ended December 31, 2008. Similar to our Convertible Debentures, interest expense is based on the effective yield, and as a result, the interest expense recorded is greater than the cash interest paid.

Included in short and long term interest expense is the amortization of the discount on the $7^{7/8}$% Senior Notes, the accretion on the debt component balance of the Convertible Debentures to face value at maturity, as well as the amortization of commitment fees and legal costs incurred for our credit facility, all totaling $2.7 million for the year ended December 31, 2008.

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 $7^{7/8}$% Senior Notes as well as any other U.S. dollar cash balances. Realized foreign exchange losses of $19.1 million for 2008, have resulted from the settlement of U.S. dollar denominated transactions. In 2007 we refinanced our U.S. dollar denominated bank loans with Canadian bank borrowings, realizing a foreign exchange gain of $47.1 million in respect of this loan. Since December 31, 2007, the Canadian dollar has weakened compared to the U.S dollar from near parity to a rate of 1.218 at December 31, 2008, resulting in a year-to-date unrealized foreign exchange loss of $11.7 million. Of this unrealized loss, $55.4 million relates to the $7^{7/8}$% Senior Notes, offset by $43.9 million of unrealized foreign exchange gains attributed to downstream transactions.

Our downstream operations are considered a self-sustaining operation with a U.S. dollar functional currency. The foreign exchange gains and losses incurred by our downstream operations relate to Canadian dollar transactions converted to U.S. dollars as their functional currency is U.S. dollars. The cumulative translation adjustment recognized in other comprehensive income represents the translation of our downstream operation's U.S. dollar functional currency financial statements to Canadian dollars using the current rate method. During 2008, the weakening of the Canadian dollar relative to the U.S. dollar resulted in a $284.7 million net cumulative translation gain (2007 – net loss of $243.6 million) as the stronger U.S. dollar results in an increase in the relative value of the net assets in our downstream operations.

Future Income Tax

Following the enactment of Bill C-52 in June 2007, we recorded a $177.7 million future income tax charge in our Second Quarter 2007 results reflecting the taxing of the temporary differences between the book value and tax basis of assets held by our Mutual Fund Trust and our other "flow through" entities. The principal source of temporary differences for our corporate entities is in respect of our property, plant and equipment and the recognition for accounting purposes of the mark-to-market value of our price risk management contracts while for our Mutual Fund Trust and other "flow through" entities, the temporary differences arise due to our net profits royalty interests. With respect to the future income tax provision for our Mutual Fund Trust and other "flow through" entities, the provision is based on the expected temporary differences and applicable income tax rates as at January 1, 2011 when the impact of Bill C-52 becomes effective and this provision will change to reflect changes in estimates of the temporary differences and legislated changes to income tax rates to be in effect on January 1, 2011.

During 2008, we recorded a $108.6 million future income tax charge reflecting the net impact of the exempt income earned by our "flow through" entities and a significant change to our estimate of the expected temporary differences of our "flow through" entities on January 1, 2011. Currently, income earned by our "flow through" entities in respect of net profits royalty interests and interest on inter-entity debt between our operating entities and our Mutual Fund Trust is exempt from income taxes as income tax liability is transferred to our Unitholders with the payment of distributions.

At the end of 2008, we had a net future income tax provision on our balance sheet of $204.0 million comprised of a $372.6 million future liability provision for our Mutual Fund Trust and other "flow through" entities and an offsetting future income tax asset of $168.6 million for our corporate entities as compared to a net future income tax provision of $86.6 million comprised of a $270.5 million provision and a $183.9 million net asset at the end of the prior year.

At the end of 2008, we estimated our unclaimed capital expenditures to be:

Tax Classification (in millions)	Trust	Upstream Operations	Downstream Operations	Total
Canadian Oil & Gas Property Expenditures	$ 514.9	$ 377.9	$ -	$ 892.8
Canadian Development & Exploration Expenditures	-	309.8	-	309.8
Unclaimed Capital Costs	-	465.0	380.0	845.0
Non-capital losses and other	28.9	778.4	272.4	1,079.7
Total	$ 543.8	$ 1,931.1	$ 652.4	$ 3,127.3

Income Tax Reassessment

In January 2009, the Canada Revenue Agency ("CRA") issued a Notice of Reassessment to Harvest Energy Trust in respect of its 2002 through 2004 taxation years claiming past taxes, interest and penalties totaling $6.2 million. The CRA has adjusted taxable income to include the net profits interest revenue to an accrual basis whereas our income tax filings have been prepared on a cash basis. Management and our legal advisors believe the reassessment by the CRA has not properly applied a provision of the Income Tax Act (Canada) that entitles income from a property to be included in taxable income in the year in which the payment is received. In addition to presenting the merit of our position to the CRA, we have filed a Notice of Objection with the CRA and expect that the matter will be referred to a judicial proceeding.

In 2005, the Harvest Energy Trust tax return was prepared on a cash basis with no taxes payable and if prepared on an accrual basis of reporting consistent with the 2002 through 2004 taxation years as reassessed by the CRA, there would be taxes owing of approximately $40 million. In 2006, the Harvest Energy Trust tax return was prepared using an accrual basis of reporting for the Net Profits Interest payments and included the incremental payments required to align the prior years' cash basis of reporting with no taxes payable.

As both management and our legal advisors believe the Income Tax Act (Canada) entitles income from a property to be reported on a cash basis prior to 2007, we expect the outcome of the CRA reassessments will be resolved with no taxes paid for taxation years 2002 through 2006. Accordingly, the amount of this contingent liability has not been accrued for the year ended December 31, 2008.

Update on the Taxation of Royalty Trusts

Following the October 31, 2006 announcement to apply a tax to the distributions from certain publicly traded mutual fund trusts, the Government of Canada introduced Bill C-52 and Bill C-28 to implement the changes. On June 22, 2007, Bill C-52 was enacted which implemented the proposals to tax publicly traded mutual fund trusts and as a result, we recorded a $177.7 million future income tax net charge in our Second Quarter 2007 results reflecting the taxing of the temporary differences between the book value and the tax basis of our assets held by our Mutual Fund Trust and our other "flow through" entities. On December 14, 2007, Bill C-28 was enacted to implement reductions in the federal corporate income tax rates from 20.5% to 19.5% in 2008 with further reductions scheduled resulting in a 15% rate as of January 1, 2012 and we adjusted our future income tax provisions accordingly.

During 2008, the Government of Canada introduced legislation to adjust the deemed provincial tax rate component for the tax on distributions from publicly traded mutual fund trusts to reflect the provincial allocation of business activity as well as legislation to enable income trusts and royalty trusts to convert to publicly traded corporations without adverse Canadian income tax consequences and also accelerated the normal growth guideline contained in Bill C-52. However, neither of these proposed legislative changes became law due to federal elections and the proroguing of Parliament deferring the process.

We continue to review and evaluate the impact of the enacted changes as well as the proposed changes and while there has been no decision at this time, we are more likely to convert to a corporation while retaining the income tax advantages until 2011.

Contractual Obligations and Commitments

We have 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. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. We also have contractual obligations and commitments that are of a less routine nature as disclosed in the following table:

	Maturity				
Annual Contractual Obligations *(000s)*	**Total**	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt[2]	**$ 1,530,728**	$ -	$ 1,530,728	$ -	$ -
Interest on long-term debt[4]	**104,781**	52,612	52,169	-	-
Interest on Convertible Debentures[3]	**325,818**	65,269	127,864	105,386	27,299
Operating and premise leases	**24,348**	7,868	13,074	2,840	566
Purchase commitments[5]	**36,537**	36,537	-	-	-
Asset retirement obligations[6]	**1,203,785**	14,214	30,790	26,958	1,131,823
Transportation [7]	**6,679**	2,744	3,202	733	-
Pension contributions[8]	**43,526**	6,900	14,217	14,791	7,618
Feedstock commitments	**319,746**	319,746	-	-	-
Total	**$ 3,595,948**	$ 505,890	$ 1,772,044	$ 150,708	$ 1,167,306

(1) As at December 31, 2008, we have entered into financial contracts for downstream production of refined products with average deliveries of approximately 20,000 bbl/d for the first half of 2009.
(2) Assumes that the outstanding Convertible Debentures either convert at the holders' option or are redeemed for Trust Units at our option.
(3) Assumes no conversions and redemption by Harvest for Trust Units at the end of the second redemption period. At the Trust's option the interest on Convertible Debentures can be settled in Trust Units.
(4) Assumes constant foreign exchange rate.
(5) Relates to drilling commitments, AFE commitments and downstream purchase commitments.
(6) Represents the undiscounted obligation by period.
(7) Relates to firm transportation commitment on the Nova pipeline.
(8) Relates to the expected contributions for employee benefit plans.

We have a number of operating leases for moveable field equipment, vehicles and office space and our commitments under those leases are noted in our annual contractual obligations table above. The leases require periodic lease payments and are recorded as either operating costs or G&A. We also finance our annual insurance premiums, whereby a portion of the annual premium is deferred and paid monthly over the balance of the term.

Off Balance Sheet Arrangements

As at December 31, 2008 and December 31, 2007, we have no off balance sheet arrangements in place.

Change In Accounting Policies

Effective January 1, 2008, we have adopted the requirements of the Canadian Institute of Chartered Accountants ("CICA") Section 3862 Financial Instruments – Disclosures, Section 3863 Financial Instruments – Presentation, and Section 1535 Capital Disclosures. The additional disclosures required as a result of adopting these new standards can be found in the notes to our consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com.

In June 2007, the CICA issued Section 3031 – Inventories, which replaces the existing standard for inventories. This standard provides additional disclosure requirements for inventories, and requires that inventories be valued at the lower of cost and net realizable value. The standard was effective for Harvest on January 1, 2008. Application of this standard did not have a material impact on our financial statements.

DISTRIBUTIONS TO UNITHOLDERS

We declare monthly distributions to Unitholders in light of our expectations of cash from operating activities and capital expenditure plans as well as debt repayment requirements. We typically declare monthly distributions for the quarter and with a longer term view of the commodity price environment, use our balance sheet to provide a stable stream of distributions from a business operating in a commodity price environment that may be volatile from time to time. Our distributions will generally exceed the net income reported in our financial statements as a result of significant non-cash charges recorded in our income statement which have no impact on cash from operating activities. Our net income will fluctuate significantly from our cash flow from operating activities.

The following table summarizes our cash from operating activities, net income (loss), distributions declared and proceeds from our distribution reinvestment programs as well as distributions as percentage of cash from operating activities for the past two years:

	Year Ended December 31		
(000s except per trust unit amounts)	**2008**	2007	Change
Cash from Operating Activities	**$ 655,877**	$ 641,313	2%
Net Income (Loss)	**$ 212,019**	$ (25,676)	926%
Distributions declared	**$ 551,325**	$ 610,280	(10%)
Per trust unit	**$ 3.60**	$ 4.40	(18%)
Distribution reinvestment proceeds	**$ 137,974**	$ 178,489	(23%)
Distributions as a percentage of cash from operating activities	**84%**	95%	(11%)

In 2008, our distributions exceeded our net income by $339.3 million with non-cash charges of $519.8 million for depletion, depreciation, amortization and accretion (“DDA&A”), a $108.6 million charge in respect of future income tax expense and an $11.7 of unrealized currency exchange losses offset by $185.9 million of unrealized gains on price risk management contracts. Our provision of $519.8 million in respect of DDA&A is based primarily on a unit-of-production amortization of our historic costs of property, plant and equipment and does not accurately represent the fair value or replacement cost of the assets. During 2007, our distributions to Unitholders exceeded our loss by $636.0 million with non-cash charges of $526.7 million for depletion and depreciation, $147.8 million in respect of unrealized price risk management contracts and a $65.8 million of future income provision somewhat offset by $55.7 million of unrealized currency exchange gains. During 2008, distributions declared represented 84% of cash from operating activities as compared to 95% in the prior year, both of which are in excess of our 55% to 80% annual target.

As we declare distributions, management, together with the Board of Directors, assess the level of our monthly distributions in light of commodity price expectations, currency exchange rates, upstream production and downstream throughput projections, operating cost forecasts, debt leverage and spending plans. On November 12, 2008 with the WTI benchmark price trading at approximately US$60.00, we declared a $0.30 distribution for the next four months to be paid on December 15, 2008, January 15, 2009, February 17, 2009 and March 16, 2009. Subsequent to this declaration, the severity of the global economic slowdown and drop in commodity prices exceeded expectations and as a result, the distributions declared in the Fourth Quarter of 2008 represent approximately 141% of our cash from operating activities before adjustment for non-cash working capital and asset retirement expenditures. With capital spending of $107.3 million in the Fourth Quarter of 2008, we have relied on other sources to fund distributions and with expectations of approximately $120 million of capital spending in the First Quarter of 2009, we will likely be relying on other sources to fund a significant portion of our distributions in the First Quarter of 2009.

After having maintained a monthly distribution of at least $0.30 from February 2006 through March 2009, we have declared a $0.05 per Trust Unit distribution for Unitholders of record on March 23, 2009 and payable on April 15, 2009 due to the challenging economic conditions; low commodity prices, capital expenditures in the First Quarter of 2009 and balance sheet liquidity. This measure is part of a business strategy to direct substantially all of our future cash flow to a combination of capital expenditures to maintain our productive capacity and improve our liquidity by reducing bank borrowings. As a result of the ongoing turmoil in global credit markets, there is also a heightened need to focus on renewing/extending our Extendible Revolving Credit Facility maturing in April 2010 under which we are currently borrowing approximately $1,250 million. We expect that with a lower level of bank borrowing, the renewal/extension of our credit facility should be less strained. Currently, debt covenants in our credit facility agreement and $7^{7/8}$Senior Note indenture that could limit our distributions are not expected to restrict distributions in the foreseeable future.

Premium Distribution, Distribution Reinvestment and Optional Trust Unit Purchase Plan

We have a Premium Distribution, Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "DRIP") that entitles eligible Unitholders to direct their distributions to the purchase of additional Trust Units at 95% of the average market price, as defined in the DRIP. Alternatively, eligible Unitholders may elect under the premium distribution plan to have their distributions invested in new Trust Units and exchanged through the DRIP broker for a premium distribution equal to 102% of the amount that the Unitholder would otherwise have received, subject to proration and withholding tax reductions in certain circumstances. Only Canadian resident Unitholders are eligible to participate in the premium distribution plan at this time.

During 2008, Unitholders elected to direct $138.0 million of distributions to either the distribution reinvestment plan or the premium distribution plan resulting in the issuance of 7,655,414 Trust Units as compared to $178.5 million and 6,809,987 Trust Units in the prior year. The optional trust unit purchase plan was not used in either 2008 or 2007.

LIQUIDITY AND CAPITAL RESOURCES

Harvest is an integrated energy trust with a declining asset base in our upstream operations and a "near perpetual" asset in our downstream operations. As well as future petroleum and natural gas prices, our upstream operations rely on the successful exploitation of our existing reserves, future development activities and strategic acquisitions to replace existing production and add additional reserves. With a prudent maintenance program, our downstream assets are expected to have a long life with additional growth in profitability available by upgrading the HSFO currently produced, enhancing our refining capability to handle a lower cost feedstock and/or expanding our refining throughput capacity. Future development activities and modest acquisitions in our upstream business as well as the maintenance program in our downstream business will likely be funded by our 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 Trust Units and incremental debt. To the extent that we finance acquisitions and growth initiatives from cash flow from operating activities, the amount of our distributions to Unitholders may be reduced. Should equity capital markets or incremental debt not be available to us, our ability to make the necessary expenditures to maintain or expand our assets may be impaired and result in reductions to future distributions paid to Unitholders. In our upstream business, it is not possible to distinguish between expenditures to maintain productive capacity and spending to increase productive capacity due to the numerous factors impacting reserve reporting and the natural decline in reservoirs and accordingly, maintenance capital is not disclosed separately.

During 2008, global economic conditions changed significantly from an expectation of strong economic growth in the first half of the year to a more broadly based credit crunch with a tightening of capital availability and higher borrowing costs during the second half of the year. As global economic conditions changed so did commodity prices with the NYMEX futures for WTI priced at US$100 per barrel in January, climbing to an all-time record of US$147 in July and then falling to approximately US$40 by the end of the year as significant economies fell into recession and the growth in developing economies slowed sharply. This has resulted in a significant reduction in the trading value of our Trust Units and has resulted in our access to capital markets becoming more difficult. These conditions have also significantly impacted our cash flow from operating activities as well as opportunities to improve our balance sheet leverage.

During 2008, cash flow from operating activities was $655.9 million including the $9.9 million increase in non-cash working capital. We declared distributions of $551.3 million ($413.3 million net of our distribution re-investment plans), required $327.5 million for capital expenditures and a further $128.8 million for our acquisition and disposition activity resulting in a net cash requirement of $213.7 million. At the end of 2008, our bank borrowings totaled $1,226.2 million, a reduction of $53.3 million over the prior year as the $239.5 million of net proceeds from the issuance of $250 million principal amount of 7.5% Convertible Unsecured Subordinated Debentures in April more than offset the net cash requirement from capital investing and distributions to Unitholders in excess of cash provided by operating activities.

For the year ended December 31, 2007, cash flow from operating activities was $641.3 million after providing $17.4 million for an increased investment in non-cash working capital with distributions to Unitholders of $610.3 million declared ($431.8 million net of Unitholder participation in our distribution re-investment plans) and $482.9 million of capital expenditures and acquisitions (net of divestitures) resulting in a net cash requirement of $273.4 million. With net proceeds of $576.0 million from the issuance of $230 million of principal amount of 7.25% Convertible Unsecured Subordinated Debentures and 13,449,250 Trust Units, drawing under our credit facilities were reduced by $302.6 million during 2007.

During the Fourth Quarter of 2008, cash flow from operating activities was $183.7 million, including an additional $89.0 million provided by a reduction in non-cash working capital. Cash flow from operating activities before changes in non-cash working capital totaled $94.8 million as compared to $71.4 million in the Fourth Quarter of 2007. After declaring distributions of $140.6 million (a $109.2 million cash requirement after Unitholder participation in our distribution reinvestment plans) and $107.3 million for capital expenditures, the net cash requirement of $32.8 million was funded by an increase in bank borrowings.

During 2008, the principal change in our capital structure was our issuance in April of $250 million principal amount of 7.5% Convertible Debentures Due 2015 with the net proceeds of $239.5 million. With lesser impact, we elected to settle the maturity of $24.3 million principal amount of 10.5% Convertible Debentures on January 31, 2008 with the issuance of 1,116,593 Trust Units rather than settling the obligation with cash and during 2008, we issued 7,655,414 Trust Units pursuant to Harvest's Premium Distribution™, Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "DRIP Plans") raising $138.0 million.

The following table summarizes our capital structure as at December 31, 2008 and 2007:

	As At December 31	
(in millions)	**2008**	2007
DEBT		
Extendible Revolving Credit Facility	**$1,226.2**	$1,279.5
7 7/8 % Senior Notes Due 2011 (US$250 million)[(1)]	**304.5**	247.8
Convertible Debentures, at principal amount [(2)]	**916.7**	691.2
Total Debt	**2,447.4**	2,218.5
Unitholders' Equity, at book value less equity component of convertible debentures		
157,200,701 issued at December 31, 2008	**2,559.2**	
148,291,170 issued at December 31, 2007		2,445.8
TOTAL CAPITALIZATION	**$5,006.6**	$4,664.3

(1) Face value converted at the period end exchange rate.

(2) See Note 12 of the Consolidated Financial Statements for the years ended December 31, 2008 and 2007 filed on SEDAR at www.sedar.com.

At the end of 2008, we had $373.8 million of unutilized borrowing capacity under our $1.6 billion Extendible Revolving Credit Facility. This syndicated covenant-based secured facility matures in April 2010 unless extended, which would require each lender to consent with respect to their individual commitments. In light of the credit crunch, we deferred requesting an extension in 2008 as some lenders may have chosen to not extend and extending lenders would have likely required increased fees and credit spreads, as well as a reduced level of commitment. At December 31, 2008, our secured debt to annualized EBITDA was 1.5 to 1.0, total debt (excluding convertible debentures) to annualized EBITDA was 1.8 to 1.0, while the secured debt to total capitalization was 25% and total debt (excluding convertible debentures) to total capitalization was 31%. For a complete description of our covenant-based credit agreement, see Note 10 to our audited consolidated financial statements for the year ended December 31, 2008 and our credit agreement filed on SEDAR at www.sedar.com.

Our cash flow risk management program includes our entering into numerous pricing contracts. We have limited our counterparties to the lenders in our Extendible Revolving Credit Facility as the security provided in our credit agreement extends to our pricing contracts and this eliminates the requirement for margin calls and the pledging of collateral as well as limits the negotiation of events of default, all of which contribute to ensuring that these contracts improve our liquidity rather than exacerbate credit concerns.

In October 2004, Harvest Operations Corp., a wholly-owned subsidiary of Harvest, issued US$250 million of principal amount $7^{7/8}$% Senior Notes and they remain outstanding at December 31, 2008. These $7^{7/8}$% Senior Notes are unsecured, require semi-annual payments of interest and mature on October 15, 2011. The most restrictive covenant of the $7^{7/8}$% Senior Notes limits the incurrence of additional indebtedness if such issuance would result in an interest coverage ratio, as defined, of less than 2.5 to 1.0 and in respect of the incurrence of secured indebtedness, limits the amount to less than 65% of the present value of future net revenues from our proved petroleum and natural gas reserves discounted at an annual rate of 10%. At the end 2008, 65% of the present value of the future net revenues from our proved petroleum and natural gas reserves discounted at an annual rate of 10% is approximately $1.9 billion.

Our $7^{7/8}$% Senior Notes are rated by both Standard and Poor’s Ratings Services (“S&P”) and Moody’s Investors Service (‘Moody’s”) who have assigned a corporate rating of “B” and “B3”, respectively, and have rated the $7^{7/8}$% Senior Notes as “CCC+” and “Caa1”, respectively. These ratings reflect Harvest’s relatively high financial leverage and inability to fund meaningful growth (or debt reduction) from internal cash flows while maintaining a significant level of distributions to Unitholders. Recently, S&P have revised its ratings outlook from stable to negative reflecting an expectation of lower upstream production and weakened financial metrics as a result of low hydrocarbon prices. In 2007, Moody’s had also cautioned that their stable outlook assumes that commodity prices and refining margins remain supportive and that the leverage is reduced before market conditions soften.

At the end of 2008, we had $916.7 million of principal amount of Convertible Debentures issued in seven series with $39.6 million of principal amount due prior to the end of 2011 and $877.1 million of principal amount due beyond 2011. As the conversion price of the outstanding Convertible Debentures ranges from $13.85 to $46.00, we do not expect a significant amount of conversion activity until the trading value of our Trust Units appreciates from its current trading range. The most restrictive term of the Convertible Debentures limits the issuance of additional Convertible Debentures if the principal amount of all issued and outstanding Convertible Debentures immediately after the issuance exceed 25% of the total market capitalization, being an aggregate of the principal amount of all issued and outstanding Convertible Debentures plus an amount equal to the current market price of all of the issued and outstanding Trust Units. At December 31, 2008, our total market capitalization was approximately $2.6 billion which would limit the issuance of any further Convertible Debentures.

During 2008, the trading value of our Trust Units ranged from a high of $26.00 in February to a low of $8.33 in October. During October, the volume of units traded and drop in trading price is generally attributed to the precipitous drop in crude oil and natural gas prices to a level that will likely result in abnormally low cash flows and the deterioration of business fundamentals beyond the normal cyclical fluctuations. The following summarizes the trading value of our Trust Units during 2008 and the first two months of 2009:

	Trading Price		
Month	**High**	**Low**	**Volume**
Canadian Trading			
January 2008	$ 23.56	$ 20.48	10,474,631
February 2008	$ 26.00	$ 22.49	8,552,342
March 2008	$ 24.13	$ 22.00	9,638,750
April 2008	$ 24.94	$ 22.23	11,965,637
May 2008	$ 25.67	$ 22.15	14,019,461
June 2008	$ 25.77	$ 23.32	9,263,955
July 2008	$ 24.60	$ 19.32	10,210,064
August 2008	$ 21.75	$ 18.90	12,078,183
September 2008	$ 21.12	$ 15.89	9,834,707
October 2008	$ 17.69	$ 8.33	26,521,040
November 2008	$ 14.09	$ 10.65	14,381,812
December 2008	$ 12.68	$ 9.42	11,179,958
January 2009	$ 11.91	$ 10.36	10,266,136
February 2009	$ 10.57	$ 5.87	13,739,710
U.S. Trading (in US$)			
January 2008	$ 23.24	$ 20.00	18,167,009
February 2008	$ 25.70	$ 22.51	15,108,961
March 2008	$ 24.49	$ 21.44	17,099,323
April 2008	$ 24.82	$ 22.06	20,845,245
May 2008	$ 26.08	$ 21.75	24,871,749
June 2008	$ 25.28	$ 23.05	16,892,369
July 2008	$ 24.30	$ 18.80	23,625,243
August 2008	$ 20.55	$ 17.73	17,597,112
September 2008	$ 20.01	$ 15.17	24,126,064
October 2008	$ 16.69	$ 7.00	65,647,621
November 2008	$ 11.55	$ 8.60	37,694,288
December 2008	$ 10.17	$ 7.26	31,705,600
January 2009	$ 10.10	$ 8.25	25,461,464
February 2009	$ 8.55	$ 4.69	36,881,966

We are authorized to issue an unlimited number of Trust Units and at the end of 2008, approximately 71% of our Unitholders were non-residents of Canada which is relatively unchanged from 66% at the end of 2007. As of February 28, 2009, we had 159,240,909 Trust Units outstanding, 7,995,016 of Unit Appreciation Rights granted (of which 2,032,922 were vested) and 649,357 awards issued under the Unit Awards Incentive Plan (of which 273,771 were vested).

On October 20, 2008, we announced that the Toronto Stock Exchange had accepted our intention to commence a Normal Course Issuer Bid to purchase for cancellation at prevailing market prices up to 14,826,261 Trust Units as well as up to $91.4 million principal amount of Convertible Debentures. To date, we have not purchased any securities pursuant to this Normal Course Issuer Bid.

We have entered into a Supply and Offtake Agreement with Vitol, an international crude oil trader, that initially required the ownership of the crude oil feedstock and substantially all of the refined product inventory at the refinery be retained by Vitol and granted Vitol the right and obligation to provide and deliver crude oil feedstock to the refinery as well as the right and obligation to purchase substantially all refined products produced by the refinery. This arrangement provides Harvest with financial support for its crude oil purchase commitments as well as working capital financing for its inventories of crude oil and substantially all refined products held for sale. For a more complete description of this Supply and Offtake Agreement, see the description of the Supply and Offtake Agreement in our Annual Information Form for the year ended December 31, 2007 filed on SEDAR at www.sedar.com. Currently, the Supply and Offtake Agreement may be terminated by either Vitol or Harvest with six months prior notice. Pursuant to the Supply and Offtake Agreement, we estimate that Vitol held inventories of VGO, crude oil feedstock (both delivered and in-transit) valued at approximately $319.7 million at the end of 2008 which would have otherwise have been assets of Harvest as compared to $843.6 million at the end of 2007.

As provided for in the Supply and Offtake Agreement and effective January 20, 2008, we entered into an independent fuel oil offtake arrangement with a wholly-owned affiliate of one of the world's largest integrated energy companies for the sale of all of our HSFO production for a period of one year with a one year renewal option requiring mutual consent. This arrangement required that we provide financing for our inventories of HSFO which at December 31, 2008 totaled $6.7 million.

Through a combination of cash from operating activities, available undrawn credit capacity and the working capital provided by the Supply and Offtake Agreement with Vitol, it is anticipated that we will have enough liquidity to fund future operations and forecasted capital expenditures although cash from operating activities used to fund ongoing operations may reduce the amount of future distributions paid to Unitholders.

SUMMARY OF FOURTH QUARTER RESULTS

	Three months ended December 31						
	2008			2007			
	Upstream	**Downstream**	**Total**	Upstream	Downstream	Total	Change
Revenues	**238,550**	**690,152**	**928,702**	308,022	624,512	932,534	0%
Royalties	**(35,963)**	**-**	**(35,963)**	(53,410)	-	(53,410)	(33%)
Net revenues	**202,587**	**690,152**	**892,739**	254,612	624,512	879,124	2%
Less:							
Purchased product for resale and processing	**-**	**629,994**	**629,994**	-	579,766	579,766	9%
Operating expenses	**82,161**	**53,395**	**135,556**	76,100	81,271	157,371	(14%)
Transportation and marketing	**3,258**	**(5,805)**	**(2,547)**	2,347	7,895	10,242	(125%)
Cash G&A	**8,299**	**440**	**8,739**	7,844	441	8,285	5%
Unit based compensation expense	**(2,197)**	**(79)**	**(2,276)**	(3,553)	48	(3,505)	(35%)
Total G&A	**6,102**	**361**	**6,463**	4,291	489	4,780	35%
Depreciation, depletion and accretion	**119,339**	**20,638**	**139,977**	115,176	17,746	132,922	5%
Net income per segment	**(8,273)**	**(8,431)**	**(16,704)**	56,698	(62,654)	(5,957)	180%
Realized gains (losses) on risk management contracts			**24,434**			(17,375)	(241%)
Unrealized gains (losses) on risk management contracts			**192,252**			(122,739)	(257%)
Interest and other financing charges			**(37,324)**			(36,959)	1%
Currency exchange (loss) gain			**(8,510)**			10,856	(178%)
Large corporation tax and other tax			**552**			1,059	(48%)
Future income tax (expense) recovery			**(76,060)**			57,530	(232%)
Net income (loss)			**78,640**			(113,585)	(169%)
Per Trust Unit, basic			**0.50**			(0.77)	(165%)
Per Trust Unit, diluted			**0.50**			(0.77)	(165%)
Cash From Operating Activities			**183,740**			87,998	109%
Per Trust Unit, basic			**1.18**			0.60	97%
Per Trust Unit, diluted			**1.10**			0.60	83%
Distributions declared			**140,646**			144,681	(3%)
Distributions declared, per Trust Unit			**0.90**			0.98	(8%)
Distributions declared as a percentage of Cash From Operations			**77%**			164%	(87%)
UPSTREAM OPERATIONS							
Daily Production							
Light / medium oil (bbl/d)			**25,088**			26,640	(6%)
Heavy oil (bbl/d)			**11,306**			13,354	(15%)
Natural gas liquids (bbl/d)			**2,770**			2,595	7%
Natural gas (mcf/d)			**96,079**			94,961	1%
Total daily sales volume (boe/d)			**55,177**			58,416	(6%)
Operating Netback(1) ($/BOE)							
Revenue			**46.99**			57.32	(18%)
Royalties			**(7.08)**			(9.94)	(29%)
Operating expense			**(16.19)**			(14.16)	14%
Transportation expense			**(0.64)**			(0.44)	45%
Operating Netback(1)			**23.08**			32.78	(30%)
Cash capital expenditures			**82,975**			30,643	171%
DOWNSTREAM OPERATIONS							
Average daily throughput (bbl/d)			**102,500**			61,717	66%
Aggregate throughput (mbbl)			**9,430**			5,678	66%
Average Refining Margin (US$/bbl)			**3.93**			6.00	(35%)
Cash capital expenditures			**24,317**			16,889	44%

(1) This is a non-GAAP measure, please refer to “Non-GAAP Measure” in this MD&A.

During the Fourth Quarter of 2008, cash from operating activities totaled $183.7 million, a $95.7 million increase as compared to $88.0 million in the prior year. The increase is primarily due to an $89.0 million reduction in working capital as compared to a $16.6 million reduction in the prior year and $24.4 million in realized gains on risk management contracts as compared to realized losses of $17.4 million in the prior year. Cash generated from our upstream operations of $108.9 million, reflects a decrease of $59.3 million as compared to $168.2 million in the prior year, primarily due to a 30% decrease in operating netbacks and a 6% decrease in production volumes. Cash generated from our downstream operations increased to $10.6 million during the Fourth Quarter of 2008, as compared to a $44.9 million cash deficiency in the prior year, reflecting the impact of the planned turnarounds in 2007, partially offset by lower refining margins in the current period.

Upstream Operations

Our 2008 Fourth Quarter revenues decreased $69.5 million compared to the prior year as a result of our realized commodity prices decreasing by $10.33/boe (18%) due to lower crude oil prices and a decrease in production volumes of 3,239 boe/d as compared to the prior period due to normal decline and a reduction in 2008 capital spending. Light/medium oil sales revenue for the three month period ended December 31, 2008 was $53.3 million (31%) lower than in same period in the prior year due to an unfavourable price variance of $43.2 million and an unfavourable volume variance of $10.1 million. Heavy oil revenues for the three months ended December 31, 2008 decreased by $15.9 million (26%) due to an unfavourable price variance of $6.7 million and an unfavourable volume variance of $9.2 million. Natural gas sales revenue increased by $5.3 million (9%) for the three months ended December 31, 2008 over the same period in 2007, which reflects a favourable price variance of $4.6 million and a favourable volume variance of $0.7 million.

For the three months ended December 31, 2008, our net royalties as a percentage of revenue were 15.1% ($36.0 million) as compared to 17.3% ($53.4 million) in the same period in 2007. Our royalty rate for the Fourth Quarter of 2008 was lower than in the same period in 2007, due to favourable one-time credits received during the period.

Operating expenses increased by $6.1 million (8%) for the three months ended December 31, 2008 as compared to the same period in the prior year, which reflects a $5.7 million increase in power and fuel costs, comprised primarily of electric power costs. The average Alberta electric power price of $95.17/MWh in the Fourth Quarter of 2008 was 54% higher than the average price of $61.76/MWh in the same period in 2007.

Transportation and marketing expense increased by $0.9 million to $3.3 million for the three months ended December 31, 2008, due to increased clean oil trucking costs associated with the two acquisitions completed in the Third Quarter of 2008.

For the three months ended December 31, 2008, cash G&A increased by $0.5 million (6%) compared to the same period in the prior year reflecting increased costs to retain technically qualified staff in the western Canadian petroleum and natural gas industry.

Capital spending in the Fourth Quarter of 2008 increased by $52.3 million to $83.0 million as compared to the prior year. The increase in spending is primarily due to increased drilling activity as we drilled 82 wells (48.0 net) in the Fourth Quarter of 2008 as compared to drilling 21 wells (10.0 net) in the Fourth Quarter of 2007.

Downstream Operations

Our 2008 Fourth Quarter gross margin increased by $15.4 million to $60.2 million as compared to $44.8 million in the same period in the prior year, reflecting increased throughput offset by lower refining margins. In the Fourth Quarter of 2008, refinery throughput averaged 102,500 bbl/d compared to 61,717 bbl/d in the prior year reflecting the impact of planned turnarounds in 2007. However, throughput was below the refinery's nameplate capacity of 115,000 bbls/d in the Fourth Quarter of 2008 due to our managing the fouling in heat exchangers, including an online partial exchanger cleaning in December. While throughput increased, our 2008 Fourth Quarter average refining margin decreased by US$2.07/bbl to US$3.93/bbl from US$6.00/bbl in the Fourth Quarter of 2007 reflecting negative gasoline crack spreads in the Fourth Quarter of 2008 and a $35.3 million write-down on inventories, which were partially offset by increased discounts relative to the WTI benchmark on our feedstock costs.

The cost of feedstock was US$48.34/bbl in the Fourth Quarter, a decrease of US$43.76/bbl compared to the prior year due to the significant quarter over quarter decrease in WTI.

Operating costs averaged $2.00/bbl of throughput for the Fourth Quarter of 2008 as compared to $3.61/bbl in the same period in the prior year. The decrease is due to turnaround activity in the prior year reducing throughput.

Capital spending increased by $7.4 million to $24.3 million in the Fourth Quarter of 2008 as compared the prior year due to spending $13.7 million to complete of our visbreaker project in November 2008.

Corporate

Interest expense increased by $0.4 million for the three months ended December 31, 2008 relative to the same period in the prior year. The increase is attributed to a $5.6 million increase in interest expense on our Convertible Debentures, with the issuance of $250 million of principle amount of 7.5% Convertible Debentures in April; a $1.2 million increase in interest expense on our U.S. dollar Senior notes, due to the strengthening of the U.S. dollar; offset by a $6.4 million decrease in interest expense on our bank borrowings, due to lower interest rates.

In the Fourth Quarter of 2008, we realized a $24.4 million gain and a $192.3 million unrealized gain on our risk management contracts as compared to a realized loss of $17.4 million and a $122.7 million unrealized loss in the same period in 2007. The realized and unrealized gains in the Fourth Quarter of 2008 is due the significant decrease in commodity prices in the period.

In the Fourth Quarter of 2008, we realized an $11.8 million loss on currency exchange transactions and an unrealized $3.3 million gain on currency translation, as compared to a $4.7 million realized gain and a $6.2 million unrealized gain in the same period in 2007. The realized losses in the Fourth Quarter of 2008 are primarily the result of our downstream operations settling trade payables as the Canadian dollar weakened, which accounted for $8.1 million of the total $11.8 million realized loss. The unrealized gain in the Fourth Quarter of 2008 relates to an increase in the net assets of our downstream operation on translation to Canadian dollars, offset by an increase in the value of our U.S. dollar denominated Senior Notes.

SUMMARY OF QUARTERLY RESULTS

The following table and discussion highlights our Fourth Quarter of 2008 relative to the preceding seven quarters:

	2008				2007			
(000s except where noted)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue, net of royalties	**$ 892,739**	$ 1,597,195	$ 1,622,079	$ 1,377,352	$ 879,124	$ 1,031,514	$ 1,133,450	$ 1,025,512
Net income (loss)	**$ 78,640**	$ 295,788	$ (162,063)	$ (346)	$ (113,585)	$ 11,811	$ 6,248	$ 69,850
Per Trust Unit, basic(1)	**$ 0.50**	$ 1.93	$ (1.07)	$ -	$ (0.77)	$ 0.08	$ 0.05	$ 0.55
Per Trust Unit, diluted(1)	**$ 0.50**	$ 1.73	$ (1.07)	$ -	$ (0.77)	$ 0.08	$ 0.05	$ 0.55
Cash from operating activities	**$ 183,740**	$ 133,493	$ 210,534	$ 128,119	$ 87,998	$ 191,049	$ 251,218	$ 111,048
Per Trust Unit, basic	**$ 1.18**	$ 0.87	$ 1.39	$ 0.85	$ 0.60	$ 1.31	$ 1.88	$ 0.87
Per Trust Unit, diluted	**$ 1.10**	$ 0.84	$ 0.83	$ 0.83	$ 0.60	$ 1.22	$ 1.67	$ 0.84
Distributions per Unit, declared	**$ 0.90**	$ 0.90	$ 0.90	$ 0.90	$ 0.98	$ 1.14	$ 1.14	$ 1.14
Total long-term financial debt	**$ 2,352,196**	$ 2,284,664	$ 2,105,998	$ 2,209,451	$ 2,172,417	$ 2,097,187	$ 1,987,352	$ 2,436,018
Total assets	**$ 5,745,407**	$ 5,659,227	$ 5,637,879	$ 5,574,528	$ 5,451,683	$ 5,585,651	$ 5,613,333	$ 5,800,346

(1) The sum of the interim periods does not equal the total per year amount as there were large fluctuations in the weighted average number of Trust Units outstanding in each individual quarter.

Net revenues are comprised of revenues net of royalties from our upstream operations as well as sales of refined products from our downstream operations. Revenues throughout 2007 remained relatively stable until the Fourth Quarter of 2007 when the refinery throughput decreased due to a planned shutdown for more than half the quarter. Throughout the first three quarters of 2008, net revenues have been the highest in Harvest's history due to strong commodity prices; however the significant decrease in commodity prices in the Fourth Quarter of 2008 resulted in a significant decrease in net revenues.

The growth in cash from operating activities is closely aligned with the trend in commodity prices for our upstream operations, reflects the cyclical nature of the downstream segment, and is significantly impacted by changes in working capital. In the Fourth Quarter of 2008, cash from operating activities has increased from the previous quarter reflecting decreased working capital requirements in our downstream business, partially offset by a $37.30/boe decrease in our upstream operating netback and a $6.54/bbl decrease in refining margins, both due to the decrease in the demand for commodities as the economy slowed.

Net income reflects both cash and non-cash items. Changes in non-cash items, including future income tax, DDA&A expense, unrealized foreign exchange gains and losses, unrealized gains on risk management contracts and Trust Unit right compensation expense cause net income to vary significantly from period to period. In the Second Quarter of 2007 Bill C-52 was enacted, which imposed a new tax on distributions from publicly traded income trusts resulting in a $177.7 million future income tax expense in the quarter. In the Fourth Quarter of 2007 Bill C-28 implemented reductions in the federal corporate income tax rates which will also apply to the tax on distributions from publicly traded mutual fund trusts, resulting in a $57.5 million future income tax recovery in the quarter. In the First Quarter of 2008, future income tax recovery of $21.8 million was recorded as a result of the reversal of temporary timing differences between depreciation recorded over the amount of tax pool claims; an additional recovery of $95.2 million was recorded in the Second Quarter of 2008; an expense of $149.5 million was recorded in the Third Quarter of 2008; and an expense of $76.1 million was recorded in the Fourth Quarter. Changes in the fair value of our risk management contracts have also contributed to the volatility in net income (loss) over the preceding eight quarters. For these reasons, our net income (loss) does not reflect the same trends as net revenues or cash from operating activities, nor is it expected to.

Total assets over the last eight quarters have remained relatively stable. The stability reflects moderate acquisition activity offset by a reduction in net book value associated with depletion and depreciation charges. Total long term financial liabilities have also remained relatively stable over the last eight quarters, reflecting moderate acquisition activity, offset by the issuance of Trust Units in the First and Second Quarters of 2007, and a net cash surplus of cash from operating activities over distributions to Unitholders.

OUTLOOK

We anticipate that 2009 will be a challenging year with the global economic slowdown and financial crisis continuing to limit liquidity in the financial markets and causing reduction in demand for commodities including gasoline and distillate products in North America and Europe. These factors will impact our performance and we have taken action to minimize the impact with sizable reductions to our capital spending plans and a “belt tightening” of expenses. In light of reduced availability of liquidity/credit and significantly reduced cash flow with lower commodity prices, we intend to be responsible and disciplined in our approach to capital expenditures to maintain our productive capacity and reduce debt.

For our upstream operations, our original capital spending plan approved spending of $250 million including the Enhanced Oil Recovery (“EOR”) projects identified in late 2007 focusing on reservoir management. In early 2009, we revised our upstream spending plan to $170 million including $110 million in the First Quarter of the year. We are continuing most of the drilling program scheduled for the First Quarter as a large percentage of the program is at Hay River where the projects remain attractive at current prices and the area is only accessible in the winter months. There are a few wells planned for southeast Saskatchewan and Cheddarville for the First Quarter of 2009 that will proceed while substantially all other drilling activity planned has been curtailed. As commodity prices continued to weaken in late 2008 and early 2009, we have re-focused our spending on projects that remain economically viable with a shift to light to medium oil prospects.

During the last three quarters of 2009, our drilling commitments will continue to be subjected to a rigorous evaluation reflecting the current commodity price outlook as well as considering the impact of costs which are expected to soften following spring break-up. However, spending on our EOR projects will continue in our larger oil reservoirs at Hay River, Bellshill Lake, Wainwright and Suffield with planned spending of $20 million. We expect our EOR projects to reduce decline rates for an extended period with improved recoveries due to maintaining reservoir pressures and the bolstering of traditional water flood projects with the introduction of chemical enhancements, such as alkaline surfactant polymers. Our continued focus on reservoir management and reduced drilling activity will likely result in a relatively stable production profile throughout 2009 with the front-end loaded Hay River production providing a "step change" to our Second Quarter production as compared to the Fourth Quarter of 2008.

We anticipate that our upstream production will average approximately 35,000 bbls/d of liquids and 90,000 mcf/d of natural gas (approximately 50,000 boe/d), with a strong Second Quarter reflecting the drilling results from Hay River. Light and medium gravity oil, including natural gas liquids, is expected to represent approximately 53% of our total production in 2009 with heavy oil and natural gas accounting for 19% and 28%, respectively. We will continue to focus on operating costs and G&A costs and pursue opportunities to reduce costs given the less active investment environment. For 2009, we are projecting our operating costs to be approximately $15.50 per boe as compared to $14.70 per boe in 2008, an increase of $0.80 per boe primarily due to reduced production volumes. We anticipate general and administrative costs to be approximately $1.50 per boe.

In our downstream operations, our capital spending will be directed to maintenance activities and incremental discretionary investments to improve reliability, increase throughput, enhance margins and reduce operating costs. While initial spending plans totaled $62 million, our revised plan of $50 million for 2009 includes predominately turnaround and reliability projects. We are now anticipating a 35-day shutdown of the hydrocracker unit for refurbishing and catalyst replacement during April, including a 21-day shutdown of the entire refinery, at a planned cost of $45 million with the expected benefit of improved distillate yields and a 1,000 bbls/d increase to the hydrocracker unit capacity. As a result of reduced cash flow, we will continue to evaluate discretionary investments at a measured pace such that we will be positioned to advance these enhancement projects quickly when the commodity price environment and credit/capital markets improve. The $2 billion refinery expansion project discussed in 2008, while still an attractive growth initiative in the appropriate economic climate, has been deferred with no further capital committed.

For 2009, we anticipate that the refinery's daily throughput will average approximately 106,000 bbl/d of feedstock with a refined product yield of 45% distillates, 29% gasoline and 26% HSFO reflecting an increased yield of distillates of approximately 1,500 bbl/d with the completion of the visbreaker expansion project in the Fourth Quarter of 2008. Similar to the Fourth Quarter of 2008, during the First Quarter of 2009 our crude oil and hydrocracker rates will continue to be limited by fouled exchangers and end of life catalyst, and both of these issues will be addressed during the planned April shutdowns. We expect that operating costs and purchased energy costs will aggregate to $5.75 per bbl of throughput with a currency exchange rate of US$0.80 per Canadian dollar. The cash flow contribution from our marketing activities in the Province of Newfoundland and Labrador is expected to add approximately $24 million of incremental cash flow to the downstream operations.

As discussed in the Cash Flow Risk Management section of this MD&A, we have entered into refined product pricing contracts that represent approximately 68% of our WTI price exposure and 18% of our refined product crack spread exposure during the first half of 2008. The heating oil price contracts provides downside protection on the price of 12,000 bbl/d to market prices plus US$13.93 per bbl when prices are lower than US$72.59 and provides a price of US$86.52 when the market price is between US$72.59 and US$86.52 with our upside participation limited to US$98.73 per bbl. Similarly, on the price of 8,000 bbl/d of fuel oil, we have price protection equivalent to market prices plus US$7.63 per bbl when prices are lower than US$49.75 and provide a price of US$57.38 when the market price is between US$49.75 and US$57.38 with our upside participation limited to US$65.89 per bbl. Beyond June 30, 2009, we have no price risk management contracts in place.

We manage our exposure to fluctuations in interest rates by maintaining a mix of short and longer term financing with the short term financing typically carrying floating interest rates and longer term financing (our $7^{7/8}$% Senior Notes and Convertible Debentures) carrying fixed rates of interest. Our Extendible Revolving Credit Facility, which had a balance of

$1,226.2 million at December 31, 2008, requires interest payments based on floating rates and accordingly, approximately 50% of our interest rate exposure is floating. Currently, our most significant exposure to increasing interest rates is through the renewal/extension of our credit facilities or the issuance of additional longer term financings as the credit spreads have increased substantially since our most recent renewal or issuance.

Our most pressing financial issues are the renewal of our credit facility with a syndicate of fourteen banks, including Canada's six largest chartered banks, followed by the maturity of the $7^{7/8}$% Senior Notes on October 15, 2011. Currently, we have $373.8 million of undrawn capacity and in the First Quarter of 2009, the drawn portion is likely to increase by approximately $150 million. We anticipate that in light of the tightened credit markets, the significant slowdown in the global economy and current commodity prices, the renewal of our credit facility may result in more onerous terms. Although lenders are currently committed to our existing credit facility until its maturity, we will likely renew credit commitments with many of our lenders in advance of the maturity date to extend the term of our available credit beyond April 2010 which may result in an increase in the credit spreads on our borrowings as well as a commitment fee. With respect to the maturity of the $7^{7/8}$% Senior Notes in 2011, we intend to create capacity in our credit facilities to enable the repayment of this obligation should alternative sources of debt and/or equity be unavailable.

At the beginning of 2009, we have $916.7 million principle amount of Convertible Debentures issued in seven series with a weighted average interest rate of approximately 7.1%. The terms of our Convertible Debentures require semi-annual payments of interest which may be settled with the issuance of Trust Units at a price equal to 95% of the weighted average trading price for the preceding 20 consecutive trading days 5 days prior to the settlement date. In addition, we may elect to satisfy the maturity of these obligations by issuing Trust Units rather than settling the obligations in cash based on the same equivalent price as the settlement of interest obligations. We anticipate that as these Convertible Debentures mature, or are converted into Trust Units before their maturity date, we will be able to retire the entire principal obligation with equity issuances. Due to an incurrence covenant based on total market capitalization, we are currently restricted from issuing an additional Convertible Debenture. See Note 12 to our audited consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com as well as the Liquidity and Capital Resources section of this MD&A for a full description of the incurrence covenant.

Overall, we expect that based on current commodity price expectations, our 2009 cash from operating activities will be significantly lower than in 2008 and that our capital expenditures and distributions to Unitholders will be constrained with the objective of reducing borrowings under our credit facilities and improving our credit profile. Distributions are approved by our Board of Directors after considering the current and expected economic conditions and in light of the significant reduction in commodity prices, we have declared a distribution of $0.05 per Trust Unit for Unitholders of record on March 23, 2009 and payable on April 15, 2009. In prior years, we have balanced our cash from operating activities and the funding of capital expenditures and distributions with reliance on proceeds from our distribution re-investment programs for shortfalls.

While we do not forecast commodity prices nor refining margins, we have entered into price risk management contracts to mitigate a substantial portion of our price volatility in the first half of 2009, with the objective of stabilizing our 2009 cash flow from operating activities. The following table reflects the sensitivity of our 2009 operations to changes in the following key factors to our business:

	Assumption	**Change**	**Impact on Cash Flow**
WTI oil price (US$/bbl)	$ 50.00	$ 5.00	$ 0.27 / Unit
CAD/USD exchange rate	$ 0.80	$ 0.05	$ 0.28 / Unit
AECO daily natural gas price	$ 5.00	$ 1.00	$ 0.17 / Unit
Refinery crack spread (US$/bbl)	$ 9.00	$ 1.00	$ 0.24 / Unit
Upstream Operating Expenses (per boe)	$ 15.00	$ 1.00	$ 0.11 / Unit

In our upstream business, we will continue to evaluate opportunities to acquire producing oil and/or natural gas properties in exchange for Trust Units as well as offer selected properties for divestment to maintain and enhance our productive capability and improve our unit operating costs.

CRITICAL ACCOUNTING ESTIMATES

There are a number of critical estimates underlying the accounting policies applied when preparing the consolidated financial statements due to timing differences between when certain activities take place and when they are reported. Changes in these estimates could have a material impact on our reported results.

Reserves

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. In the process of estimating the economically recoverable oil and natural gas reserves and related future net cash flows, we incorporate 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 oil and gas prices and quality differentials; and
- Future development costs.

We follow the full cost method of accounting for our oil and natural gas activities. All costs of acquiring oil and natural gas properties and related exploration and development costs, including overhead charges directly related to these activities, are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against income, and renewals and enhancements that extend the economic life of the capital assets are capitalized. The provision for depletion and depreciation of petroleum and natural gas assets is calculated on the unit-of-production method based on proved reserves as estimated by independent petroleum engineers.

Reserve estimates impact net income through depletion, the determination of asset retirement obligations and the application of an impairment test. Revisions or changes in the reserve estimates can have either a positive or a negative impact on net income, capital assets and asset retirement obligations.

Asset Retirement Obligations

In the determination of our asset retirement obligations, management is required to make a significant number of estimates with respect to activities that will occur in many years to come. In arriving at the recorded amount of the asset retirement obligation numerous assumptions are made with respect to ultimate settlement amounts, inflation factors, credit adjusted risk free discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligation also results in an increase to the carrying cost of capital assets. The obligation accretes to a higher amount with the passage of time as it is determined using discounted present values. A change in any one of the assumptions could impact the estimated future obligation and in return, net income. It is difficult to determine the impact of a change in any one of our assumptions. As a result, a reasonable sensitivity analysis cannot be performed.

Impairment of Capital Assets

Numerous estimates and judgments are involved in determining any potential impairment of capital assets. The most significant assumptions in determining future cash flows are future prices and reserves for our upstream operations and expected future refining margins and capital spending plans for our downstream operations.

The estimates of future prices and refining margins require significant judgments about highly uncertain future events. Historically, oil, natural gas and refined product prices have exhibited significant volatility from time to time. The prices used in carrying out our impairment tests for each operating segment are based on prices derived from a consensus of future price forecasts among industry analysts. Given the number of significant assumptions required and the possibility that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate.

If forecast WTI crude oil prices were to fall by 40%, the initial assessment of impairment of our upstream assets would not change; however, below that level, we would likely experience an impairment. Although oil and natural gas prices fluctuate a great deal in the short-term, they are typically stable over a longer time horizon. This mitigates potential for impairment.

Similarly, for our downstream operations, if forecast refining margins were to fall by more than 15%, it is likely that our downstream assets would experience an impairment despite the expected seasonal volatility in earnings.

Reductions in estimated future prices may also have an impact on estimates of economically recoverable proved reserves. It is difficult to determine and assess the impact of a decrease in our proved reserves on our impairment tests. The relationship between the reserve estimate and the estimated undiscounted cash flows is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment.

Goodwill

Goodwill is recorded on a business combination when the total purchase consideration exceeds the fair value of the net identifiable assets and liabilities of the acquired entity. The goodwill balance is not amortized, however, and must be assessed for impairment at least annually. Impairment is initially determined based on the fair value of a reporting unit compared to its book value. Any impairment must be charged to earnings in the period the impairment occurs. Harvest has a goodwill balance for each of our upstream and downstream operations. As at December 31, 2008, we have determined there was no goodwill impairment in either of our reporting units.

Employee Future Benefits

We maintain a defined benefit pension plan for the employees of North Atlantic. Obligations under employee future benefit plans are recorded net of plan assets where applicable. An independent actuary determines the costs of our employee future benefit programs using the projected benefit method. The determination of these costs requires management to estimate or make assumptions regarding 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 our employee future benefit plans could increase or decrease if there were to be a change in these estimates. Pension expense represented less than 0.5% of our total expenses for 2008 (2007 - 0.5%).

Purchase Price Allocations

Business acquisitions are accounted for by the purchase method of accounting. Under this method, the purchase price is allocated to the assets acquired and the liabilities assumed based on the fair values at the time of the acquisition. The excess of the purchase price over the assigned fair values of the identifiable assets and liabilities is allocated to goodwill. In determining the fair value of the assets and liabilities we are often required to make assumptions and estimates about future events, such as future oil and gas prices, refining margins and discount rates. Changes in any of these assumptions would impact amounts assigned to assets and liabilities and goodwill in the purchase price allocation and as a result, future net earnings.

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062 Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. The new Section will be effective on January 1, 2009. Section 3062 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. We are currently evaluating the impact of the adoption of this new section, however do not expect a material impact on our consolidated financial statements.

In December 2008, the CICA issued section 1582, Business Combinations, replacing Section 1581 of the same name. The new Section will be effective on January 1, 2011 with prospective application. Under the new guidance, the purchase price used in a business combination is based on the fair value of shares exchanged at their market price at the date of the exchange. Currently the purchase price used is based on the market price of the shares for a reasonable period before and after the date the acquisition is agreed upon and announced. This new guidance generally requires all acquisition costs to be expensed, while the current standard requires capitalization as part of the purchase price. Contingent liabilities are to be recognized at fair value at the acquisition date and remeasured at fair value through earnings each period until settled. While under the current standard only contingent liabilities that are resolved and payable are included in the cost to acquire the business. In addition, negative goodwill is required to be recognized immediately in earnings, unlike the current requirement to eliminate it by deducting it from non-current assets in the purchase price allocation.

International Financial Reporting Standards

In February 2008, the CICA Accounting Standards Board ("ASB") announced that Canadian public reporting issuers will be required to report under International Financial Reporting Standard ("IFRS") commencing January 1, 2011 which will require comparative IFRS information for the 2010 year end. In mid-2008, the ASB issued an exposure draft to incorporate IFRS into the Canadian accounting standards. In September 2008, the International Accounting Standards Board ("IASB") issued an exposure draft proposing amendments for first time adopters of IFRS to enable an entity to measure exploration and evaluation assets at the amount determined under the entity's previous accounting principles and it also provides for the measurement of oil and gas assets in the development or production phase, among other things, by allocating the amount determined by the entity's previous accounting principles to the underlying assets on a pro rata basis using reserve volumes or reserve values at the date of transition. If formally approved by the IASB, these amendments will substantially ease the adoption of IFRS for Harvest. We have determined that our accounting for property, plant and equipment will be impacted as we currently use the full cost method of accounting in accordance with the CICA Accounting Guideline 16: "Oil and Gas Accounting – Full Cost." At this time, the full impact of conversion to IFRS on Harvest's consolidated financial statements is not reasonably determinable.

We have established an IFRS Conversion Plan and have staffed a project team with regular reporting to our senior management team and to the Audit Committee of the Board of Directors. We have completed an initial assessment of the differences between Canadian accounting standards and IFRS and are currently completing a comprehensive assessment of the impact of adopting IFRS on our accounting policies, information technology and data systems, internal control over financial reporting, disclosure controls and procedures, financial reporting expertise as well as business activities that may be influenced such as debt covenants, capital requirements and compensation arrangements.

OPERATIONAL AND OTHER BUSINESS RISKS

Both Harvest's upstream operations and its downstream operations are conducted in the same business environment as most other operators in the respective businesses and the business risks are very similar. However, our structure as a publicly traded mutual fund trust is significantly different than that of a traditional corporation with share capital and there are some unique business risks of our structure. In addition, Harvest's monthly cash distributions limits its accumulation of capital resources from internal sources. We intend to continue executing our business plan to create value for Unitholders by increasing the net asset value per Trust Unit with our risk management activities carried out under policies approved by our Board of Directors.

We have segregated the identification of business risks into those generally applicable to upstream operations as well as downstream operations and those applicable to our royalty trust structure and should be read in conjunction with the full description of these risks in our Annual Information Form for the year ended December 31, 2008 to be filed on www.sedar.com. The following summarizes the more significant risks:

Upstream Operations

- Prices received for petroleum and natural gas have fluctuated widely in recent years and are also impacted by the volatility in the Canadian/US currency exchange rate.
- The differential between light oil and heavy oil compounds the fluctuations in the benchmark oil prices.
- 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.
- The production of petroleum and natural gas may involve a significant use of electrical power and since de-regulation of the electric system in Alberta, electrical power prices in Alberta have been volatile.
- The markets for petroleum and natural gas produced in western Canada depend upon available capacity to refine crude oil and process natural gas as well as pipeline capacity to transport the products to consumers.

- The reservoir and recovery information in reserve reports are estimates and actual production and recovery rates may vary from the estimates and the variations may be significant.
- Absent capital reinvestment, production levels from petroleum and natural gas properties will decline over time and absent commodity price increases, cash generated from operating these assets will also decline.
- Prices paid for acquisitions are based in part on reserve report estimates and the assumptions made preparing the reserve reports are subject to change as well as geological and engineering uncertainty.
- The operation of petroleum and natural gas properties is subject to environmental regulation pursuant to local, provincial and federal legislation and a breach of such legislation may result in the imposition of fines as well as higher operating standards that may increase costs.

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 volatile refining margins.
- The prices for crude oil and refined products are generally based in US dollars while our operating costs are denominated in Canadian dollars which introduces currency exchange rate exposure.
- Crude oil feedstock is delivered to our refinery via waterborne vessels which could experience delays in transporting supplies due to weather, accidents, government regulations or third party actions.
- Over 60% of our feedstock in 2008 was supplied from sources in Iraq and if Iraq curtails supply, we may not be able to find another source with an adequate amount of similar type of crude oil.
- We are relying on the creditworthiness of Vitol for our purchase of feedstock and should their creditworthiness deteriorate, crude oil suppliers may restrict the sale of crude oil to Vitol.
- Our refinery is a single train integrated interdependent facility which could experience a major accident, be damaged by sever weather or otherwise be forced to shutdown which may reduce or eliminate our cash flow.
- Our refining operations which include the transportation and storage of a significant amount of crude oil and refined products 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 our property and/or the property of others along with significant other liabilities in connection with a discharge of materials.
- The production of aviation fuels subjects us to liability should contaminants in the fuel result in aircraft engines being damaged and/or aircraft crashes.
- Collective agreements with our employees and the United Steel Workers of America may not prevent a strike or work stoppage and future agreements may result in an increase in operating costs.
- Refinery operations are subject to environmental regulation pursuant to local, provincial and federal legislation and a breach of such legislation may result in the imposition of fines as well as higher operating standards that may increase costs.

General Business Risks

- The loss of a member to our senior management team and/or key technical operations employee could result in a disruption to either our upstream or downstream operations.
- Our credit facility and other financing agreements contain financial covenants and maturity dates that may limit our ability to sell assets, enter into certain financing arrangements and/or pay distributions to Unitholders.
- Variations in interest rates on our current and/or future financing arrangements may result in significant increases in our borrowing costs and result in less cash available for distributions to Unitholders.
- Our crude oil sales and refining margins are denominated in US dollars while we pay distributions to our Unitholders in Canadian dollars which results in a currency exchange exposure.

Royalty Trust Structural Risks

- Trust Units are hybrid securities in that they share certain attributes common to both equity securities and debt instruments and represent a fractional interest in the Trust.
- Recent changes to income tax legislation related to the royalty trust structure will result in a tax, at the trust level of our structure, on distributions from Harvest at rates of tax comparable to the combined federal and provincial corporate income tax rates in Canada and to treat such distributions as dividends to the Unitholders for income tax purposes.

CHANGES IN REGULATORY ENVIRONMENT

On October 25, 2007, the Government of Alberta released its New Royalty Framework (the "NRF") outlining changes that increase the royalty rates on conventional oil and gas, oil sands and coal bed methane using a price-sensitive and volume-sensitive sliding rate formula for both conventional oil and natural gas. These proposals were given Royal Assent on December 2, 2008 and became effective January 1, 2009. Prior to the NRF, the amount of royalties payable was influenced by the oil price, oil production, density of oil and the vintage of the oil with the rate ranging from 10% to 35% and with respect to natural gas production, the royalty reserved was between 15% to 35% depending on the a prescribed or corporate average reference price and subject to various incentive programs.

The NRF sets royalty rates for conventional oil by a single sliding rate formula which is applied monthly and increases the range of royalty rates to up to 50% and with rate caps once the price of conventional oil reaches $120 per barrel. With respect to natural gas production, the royalties outlined in the NRF are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches $16.59 per GJ.

The NRF also includes a policy of "shallow rights reversion." The shallow rights reversion policy affects all petroleum and natural gas agreements, however, the timing of the reversion will differ depending on whether the leases and licences were acquired prior to or subsequent to January 1, 2009. Leases granted after January 1, 2009 will be subject to shallow rights reversion at the expiry of the primary term, and in the event of a licence, the policy will apply after the expiry of the intermediate term. Holders of leases and licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights which will be implemented three years from the date of the notice. The lease or licence holder can make a request to extend this period. The Government intends this policy to maximize the development of currently undeveloped resources by having the mineral rights to shallow gas geological formations that are not being developed revert back to the Government and be made available for resale.

On April 10, 2008, the Government of Alberta 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 for wells deeper than 2,500 meters will create a sliding scale of royalty credit according to depth of up to $3,750/meter.

On November 19, 2008, the Government of Alberta announced the introduction of a five year program of Transitional Royalty Plan (the "TRP") which effective January 1, 2009, 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.

Based on the information available and assuming royalties will continue to be based on field gate prices realized by producers, our analysis indicates that if our field gate prices for conventional oil are less than $53.00, our oil royalties will be lower under the NRF and if prices are higher, our royalties will increase and similarly for natural gas, if our gas plant prices are less than $7.00, our royalties will be lower and if prices are higher, our royalties will increase. Of particular concern is the royalty rates on natural gas where production from recently drilled wells may qualify as high productivity for a period of time and attract a royalty that is 15% to 20% higher than under the current royalty regime and this could significantly penalize the economics of our drilling of natural gas wells. Generally, we will pay higher royalties if commodity prices are high and lower royalties on most of our wells as they will be considered to be low productivity wells.

For a detailed discussion of our regulatory environment, please refer to the discussion of Industry Conditions in the General Business Description of our Annual Information Form for the year ended December 31, 2008 which will be filed on SEDAR at www.sedar.com

In 2007, the Government of Alberta introduced the Climate Change and Emissions Management Amendment Act which intends to reduce greenhouse gas 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 real 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.

In 2002, the Government of Canada ratified the Kyoto Protocol which calls for Canada to reduce its greenhouse gas 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 greenhouse gas 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 greenhouse gas 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 greenhouse gas 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 greenhouse gases 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.

DISCLOSURE CONTROLS AND PROCEDURES

Under the supervision of our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2008 as defined under the rules adopted by the Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of December 31, 2008, our disclosure controls and procedures were effective to ensure that information required to be disclosed by Harvest in reports it files or submits to Canadian and U.S. securities authorities was recorded, processed, summarized and reported within the time period specified in Canadian and U.S. securities laws and was accumulated and communicated to Harvest's 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 is designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with Canadian Generally Accepted Accounting Principles. 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, 2008. The evaluation was based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management has concluded that as of December 31, 2008, the design and operation of internal controls were effective..

The effectiveness of our internal control over financial reporting as of December 31, 2008 was audited by KPMG, an independent registered public accounting firm, as stated in their report, which is included in our audited consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com.

During the year ended December 31, 2008, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Based on their 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.

ADDITIONAL INFORMATION

Further information about us, including our Annual Information Form, can be accessed under our public filings found on SEDAR at www.sedar.com or at www.harvestenergy.ca. Information can also be found by contacting our Investor Relations department at (403) 265-1178 or at 1-866-666-1178.

MANAGEMENT'S REPORT

In management's opinion, the accompanying consolidated financial statements of Harvest Energy Trust (the "Trust") have been prepared within reasonable limits of materiality and in accordance with Canadian generally accepted accounting principles. 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 March 2, 2009. 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, 2008.

To meet its responsibility for reliable and accurate financial statements, management has established and monitors systems of internal control 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 (COSO). We have concluded that as of December 31, 2008, 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 and the Trusts' internal control over financial reporting have been examined by KPMG LLP, Independent Registered Public Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles. The Independent Registered Public Accountants Report outlines the scope of their examination and sets forth their opinion on the effectiveness of internal controls over financial reporting.

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 Independent Registered Public Accountants and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Trust.

(signed)
John E. Zahary
President and
Chief Executive Officer

(signed)
Robert W. Fotheringham
Chief Financial Officer

Calgary, Alberta
March 2, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Harvest Operations Corp. on behalf of Harvest Energy Trust and the Unitholders of Harvest Energy Trust

We have audited Harvest Energy Trust's ("the Trust") internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trust's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report. Our responsibility is to express an opinion on the Trust's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

An entity's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. An entity's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and directors of the entity; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the entity's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have conducted our audits on the consolidated financial statements in accordance with Canadian generally accepted auditing standards. With respect to the years ended December 31, 2008 and 2007, we also have conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our report dated March 2, 2009, expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 2, 2009

AUDITORS' REPORT

To the Unitholders of Harvest Energy Trust

We have audited the consolidated balance sheets of Harvest Energy Trust (the "Trust") as at December 31, 2008 and 2007 and the consolidated statements of income (loss) and comprehensive income (loss), unitholders' equity and cash flows for each of the years in the two-year period ended December 31, 2008. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2008 and 2007 and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2008 in accordance with Canadian generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust's internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 2, 2009 expressed an unqualified opinion on the effectiveness of the Trust's internal control over financial reporting.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 2, 2009

CONSOLIDATED BALANCE SHEETS
As at December 31
(thousands of Canadian dollars)

		2008		2007
Assets				
Current assets				
Accounts receivable and other	**$**	**173,341**	$	215,803
Fair value of risk management contracts *[Note 20]*		**36,087**		16,442
Prepaid expenses and deposits		**11,843**		15,144
Inventories *[Note 5]*		**55,788**		58,934
		277,059		306,323
Property, plant and equipment *[Note 6]*		**4,468,505**		4,197,507
Intangible assets *[Note 7]*		**106,002**		95,075
Goodwill *[Note 4]*		**893,841**		852,778
	$	**5,745,407**	$	5,451,683
Liabilities and Unitholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities *[Note 8]*	**$**	**210,097**	$	270,243
Cash distribution payable		**47,160**		44,487
Current portion of convertible debentures *[Note 12]*		**2,513**		24,273
Fair value deficiency of risk management contracts *[Note 20]*		**235**		131,020
		260,005		470,023
Bank loan *[Note 10]*		**1,226,228**		1,279,501
$7^{7/8}$% Senior notes *[Note 11]*		**298,210**		241,148
Convertible debentures *[Note 12]*		**825,246**		627,495
Fair value deficiency of risk management contracts *[Note 20]*		**-**		35,095
Asset retirement obligation *[Note 9]*		**277,318**		213,529
Employee future benefits *[Note 19]*		**10,551**		12,168
Deferred credit		**522**		710
Future income tax *[Note 18]*		**203,998**		86,640
Unitholders' equity				
Unitholders' capital *[Note 13, 14]*		**3,897,653**		3,736,080
Equity component of convertible debentures		**84,100**		39,537
Contributed surplus *[Note 15]*		**6,433**		-
Accumulated income		**458,884**		246,865
Accumulated distributions		**(1,891,674)**		(1,340,349)
Accumulated other comprehensive income (loss) *[Note 3]*		**87,933**		(196,759)
		2,643,329		2,485,374
	$	**5,745,407**	$	5,451,683

Commitments, contingencies and guarantees *[Note 22]*
Subsequent events *[Note 24]*
See accompanying notes to these consolidated financial statements.

Approved by the Board of Directors:

(signed)
William D. Robertson
Director

(signed)
Hector J. McFadyen
Director

CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

For the Years Ended December 31

(thousands of Canadian dollars, except per Trust Unit amounts)

		2008		2007
Revenue				
Petroleum, natural gas, and refined product sales	**$**	**5,737,809**	$	4,283,013
Royalty expense		**(248,445)**		(213,413)
		5,489,364		4,069,600
Expenses				
Purchased products for processing and resale		**3,850,507**		2,667,714
Operating		**537,149**		530,208
Transportation and marketing		**34,243**		46,916
General and administrative *[Note 17]*		**34,743**		36,328
Realized net losses on risk management contracts		**200,782**		26,291
Unrealized net losses (gains) on risk management contracts		**(185,921)**		147,781
Interest and other financing charges on short term debt, net		**295**		5,584
Interest and other financing charges on long term debt		**146,375**		152,201
Depletion, depreciation, amortization and accretion		**519,811**		526,741
Currency exchange loss (gain)		**30,882**		(109,316)
Large corporations tax and other tax		**(81)**		(974)
Future income tax expense *[Note 18]*		**108,560**		65,802
		5,277,345		4,095,276
Net income (loss) for the year		**212,019**		(25,676)
Other comprehensive income (loss)				
Cumulative translation adjustment		**284,692**		(243,632)
Comprehensive income (loss) for the year *[Note 3]*	$	**496,711**	$	(269,308)
Net income (loss) per Trust Unit, basic *[Note 14]*	**$**	**1.39**	$	(0.19)
Net income (loss) per Trust Unit, diluted *[Note 14]*	**$**	**1.39**	$	(0.19)

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY

For the Years Ended December 31

(thousands of Canadian dollars)

	Unitholders' Capital	Equity Component of Convertible Debentures	Contributed Surplus	Accumulated Income	Accumulated Distributions	Accumulated Other Comprehensive Income (Loss)
At December 31, 2006	**$3,046,876**	**$ 36,070**	**$ -**	**$ 271,155**	**$ (730,069)**	**$ 46,873**
Adjustment arising from change in accounting policies	(49)	-	-	1,386	-	-
Issued for cash						
February 1, 2007	143,834	-	-	-	-	-
June 1, 2007	230,029	-		-	-	-
Equity component of convertible debenture issuances						
7.25% Debentures Due 2014	-	13,100	-	-	-	-
Convertible debenture conversions						
9% Debentures Due 2009	250	-	-	-	-	-
8% Debentures Due 2009	513	(4)	-	-	-	-
6.5% Debentures Due 2010	882	(55)	-	-	-	-
10.5% Debentures Due 2008	2,999	(627)	-	-	-	-
6.40% Debentures Due 2012	122	(10)	-	-	-	-
7.25% Debentures Due 2013	244	(8)	-	-	-	-
7.25% Debentures Due 2014	157,139	(8,929)	-	-	-	-
Exercise of unit appreciation rights and other	658	-	-	-	-	-
Issue costs	(25,906)	-	-	-	-	-
Currency translation adjustment	-	-	-	-	-	(243,632)
Net loss	-	-	-	(25,676)	-	-
Distributions and distribution reinvestment plan	178,489	-	-	-	(610,280)	-
At December 31, 2007	**3,736,080**	**39,537**	**-**	**246,865**	**(1,340,349)**	**(196,759)**
Equity component of convertible debenture issuances						
7.5% Debentures Due 2015	-	51,000	-	-	-	-
Convertible debenture conversions						
9% Debentures Due 2009	32	-	-	-	-	-
8% Debentures Due 2009	141	(1)	-	-	-	-
10.5% Debentures Due 2008	13	(3)	-	-	-	-
Redemption of convertible debentures						
10.5% Debentures Due 2008 *[Note 12]*	24,249	(6,433)	6,433	-	-	-
Exercise of unit appreciation rights and other	1,494	-	-	-	-	-
Issue costs	(2,330)	-	-	-	-	-
Currency translation adjustment	-	-	-	-	-	284,692
Net income	-	-	-	212,019	-	-
Distributions and distribution reinvestment plan	137,974	-	-	-	(551,325)	-
At December 31, 2008	**$3,897,653**	**$ 84,100**	**$ 6,433**	**$ 458,884**	**$ (1,891,674)**	**$ 87,933**

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31
(thousands of Canadian dollars)

		2008		2007
Cash provided by (used in)				
Operating Activities				
Net income (loss) for the year	**$**	**212,019**	$	(25,676)
Items not requiring cash				
Depletion, depreciation, amortization and accretion		**519,811**		526,741
Unrealized currency exchange loss (gain)		**11,736**		(55,725)
Non-cash interest expense and amortization of finance charges		**14,197**		12,043
Unrealized loss (gain) on risk management contracts *[Note 20]*		**(185,921)**		147,781
Future income tax expense		**108,560**		65,802
Unit based compensation expense (recovery)		**(1,577)**		743
Employee benefit obligation		**(1,618)**		(61)
Other non-cash items		**(5)**		139
Settlement of asset retirement obligations *[Note 9]*		**(11,418)**		(13,090)
Change in non-cash working capital		**(9,897)**		(17,384)
		655,887		641,313
Financing Activities				
Issue of Trust Units, net of issue costs		**-**		354,549
Issue of convertible debentures, net of issue costs *[Note 12]*		**239,498**		220,488
Bank repayments *[Note 10]*		**(52,413)**		(291,947)
Financing costs		**(228)**		(273)
Cash distributions		**(410,678)**		(433,699)
Change in non-cash working capital		**4,098**		(1,223)
		(219,723)		(152,105)
Investing Activities				
Additions to property, plant and equipment		**(327,474)**		(344,785)
Business acquisitions		**(36,756)**		(170,782)
Property acquisitions		**(138,493)**		(27,943)
Property dispositions		**46,476**		60,569
Change in non-cash working capital		**24,274**		(14,710)
		(431,973)		(497,651)
Change in cash and cash equivalents		**4,191**		(8,443)
Effect of exchange rate changes on cash		**(4,191)**		(1,563)
Cash and cash equivalents, beginning of year		**-**		10,006
Cash and cash equivalents, end of year	**$**	**-**	$	-
Interest paid	**$**	**115,209**	$	130,990
Large corporation tax and other tax paid	**$**	**(81)**	$	442

See accompanying notes to these consolidated financial statements.

1. Nature of Operations and Structure of the Trust

Harvest Energy Trust (the "Trust") is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta on July 10, 2002 and is governed pursuant to the Amended and Restated Trust Indenture dated May 20, 2008 between Harvest Operations Corp. ("Harvest Operations"), a wholly owned subsidiary and manager of the Trust, and Valiant Trust Company as Trustee (the "Trust Indenture"). The purpose of the Trust is to indirectly exploit, develop and hold interests in petroleum and natural gas properties and refining and marketing assets through investments in the securities of its subsidiaries and net profits interests in petroleum and natural gas properties. The beneficiaries of the Trust are the holders of its Trust Units (the "Unitholders") who receive monthly distributions from the Trust's net cash flow from its various investments after the provision for interest due to the holders of convertible debentures. Pursuant to the Trust Indenture, the Trust is required to distribute 100% of its taxable income to its Unitholders each year. In compliance with the mutual fund trust requirements of the Income Tax Act (Canada), the Trusts' activities are limited to holding and administering permitted investments and making distributions to its Unitholders.

The business of the Trust is carried on by Harvest Operations and other operating subsidiaries of the Trust, including North Atlantic Refining Limited Partnership. The activities of Harvest Operations and the Trust's subsidiaries are financed through interest bearing notes from the Trust, net profit interests issued to the Trust, and third party debt such as bank debt and the $7^{7/8}$% Senior Notes. The net profit interests are determined pursuant to the terms of each respective net profit interest agreement. The Trust is entitled to net profit interests equal to the amount by which 99% of the gross proceeds from the sale of production from petroleum and natural gas properties exceed 99% of certain deductible expenditures. Under the terms of the net profits interests agreements, deductible expenditures may include discretionary amounts to fund capital expenditures, to repay third party debt and to provide for working capital required to carry out the operations of the operating subsidiaries.

Harvest is an integrated energy trust with petroleum and natural gas operations focused on the operation and further development of assets in western Canada ("upstream operations") and a refining and marketing business focused on the safe operation of a medium gravity sour crude hydrocracking refinery and a retail and wholesale petroleum marketing business both located in the Province of Newfoundland and Labrador ("downstream operations").

References to "Harvest" refer to the Trust on a consolidated basis. References to "North Atlantic" refer to Harvest Refining General Partnership and its subsidiaries, all of which are 100% owned by Harvest.

2. Significant Accounting Policies

These financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These principles differ in certain respects from accounting principles generally accepted in the United States of America ("U.S. GAAP") and to the extent that the differences materially affect Harvest, they are described in Note 23.

(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.

(b) Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the period. Specifically, amounts recorded for depletion, depreciation, amortization and accretion expense, asset retirement obligations, fair value of risk management contracts, employee future benefits and amounts used in the impairment tests for intangible assets, goodwill, inventory and property, plant and equipment are based on estimates. These estimates include petroleum and natural gas reserves, future petroleum and natural gas prices, future refined product prices, future interest and currency exchange rates and future costs required to develop those reserves as well as other fair value assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be material.

(c) 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. Concurrent with the recognition of revenue from the sale of refined products and included in purchased products for resale and processing are associated transportation charges. Revenues for retail services are recorded when the services are provided.

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 above Platt's with an interruption formula. The full effect of rate regulation is reflected in the product sales revenue as recorded by Harvest.

(d) 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. The costs of parts and supplies inventories are determined under the average cost method.

(e) Joint Interest and Partnership Accounting

The subsidiaries of Harvest conduct substantially all of their petroleum and natural gas production activities through joint interests and through partnerships. The consolidated financial statements reflect only Harvest's proportionate interest in such activities.

(f) Property, Plant, and Equipment

Upstream Operations

Harvest follows the full cost method of accounting for its petroleum and natural gas activities. All costs of acquiring petroleum and natural gas properties, whether productive or unproductive, related development costs, and overhead charges directly related to these activities, are capitalized and accumulated in one cost centre. Maintenance and repair costs that do not extend or enhance the recoverable reserves are charged against income.

Proceeds from the sale of petroleum and natural gas properties are applied against capital costs. Gains and losses are not recognized on the disposition of petroleum and natural gas properties unless that disposition would alter the rate of depletion and depreciation by 20% or more.

Provision for depletion and depreciation of petroleum and natural gas assets is calculated using the unit-of-production method, based on proved reserves net of royalties as evaluated by independent petroleum engineers. The cost basis used for the depletion and depreciation provision is the capitalized costs of petroleum and natural gas assets including undeveloped property plus the estimated future development costs of proved undeveloped reserves. Reserves are converted to equivalent units on the basis of six thousand cubic feet of natural gas to one barrel of petroleum, reflecting the approximate relative energy content.

Harvest places a limit on the aggregate carrying amount of property, plant and equipment associated with petroleum and natural gas activities which may be amortized to depletion and depreciation in future periods. Impairment is recognized when the carrying amount of the petroleum and natural gas assets exceeds the sum of the undiscounted future cash flows expected from the proved reserves.

To recognize impairment, Harvest would then measure the amount of impairment by comparing the carrying amounts of the petroleum and natural gas assets to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves using the risk-free discount rate. Any excess carrying amount above the net present value of Harvest's future cash flows would be a permanent impairment and reflected as a charge to net income for the period.

Cash flows are calculated based on future price estimates, adjusted for Harvest's contractual arrangements related to pricing and quality differentials.

The cost of unproved properties is excluded from the impairment test calculation described above and subject to a separate impairment test. An impairment of unproved properties is recognized when the cost base exceeds the fair value determined by a reference to market prices, historical experience or a third party independent evaluator. There were no impairment write downs for petroleum and natural gas assets for the years ended December 31, 2008 and 2007.

Downstream Operations
Property, plant and equipment related to the refining assets are recorded at cost. Depreciation of recorded cost less salvage value is provided on a straight-line basis over the estimated useful life of the assets as set out below. Any gains or losses on disposal of individual assets are recognized in the year of disposal.

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

Maintenance and repair costs, including major maintenance activities, are expensed as incurred. Improvements that increase or prolong the service life or capacity of an asset are capitalized.

Property, plant and equipment related to refining assets are tested for recovery whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Property, plant and equipment related to refining assets are not recoverable if their carrying amounts exceed the sum of the undiscounted cash flows expected to result from their use and eventual disposition. If property, plant and equipment related to refining assets are not recoverable, an impairment loss is recognized in an amount by which their carrying amount exceeds their fair value, with fair value determined based on discounted estimated net cash flows. There was no impairment write-down for refining assets for the years ended December 31, 2008 and 2007.

(g) Goodwill and Other Intangible assets
Goodwill is recognized when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business. Goodwill is carried at cost less impairment and is not amortized. The carrying amount of goodwill is assessed for impairment annually at year-end or more frequently if events occur that could result in an impairment. The goodwill impairment test is a two step test. In the first step, the carrying amount of the assets and liabilities, including goodwill, is compared to the fair value of the reporting unit. The fair value of a reporting unit is determined by calculating the present value of the expected future cash flows from the reporting unit. If the fair value is less than the carrying amount of the reporting unit, a potential impairment of goodwill may exist requiring the second test to be performed. Impairment is measured by allocating the fair value of the reporting unit, as determined in the first test, over the fair value of the identifiable assets and liabilities. The excess of the fair value of the reporting unit over the fair value of the identifiable assets and liabilities represents the fair value of goodwill. The excess of the book value of goodwill over this implied fair value is then recognized as an impairment and charged to income in the period in which it occurs. There were no impairment charges recorded in either of the years ended December 31, 2008 and 2007.

Intangible assets with determinable useful lives are amortized using the straight line method over the estimated lives of the assets, which range from 5–20 years. The amortization methods and estimated service lives are reviewed annually. The carrying amounts of intangible assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable. Intangibles are not recoverable if their carrying amounts exceed the sum of the undiscounted cash flows expected to result from their use and eventual disposition. If intangibles are not recoverable, an impairment loss is recognized in an amount by which their carrying amount exceeds their fair value, with fair value determined based on discounted estimated net cash flows. There was no impairment write-down for the years ended December 31, 2008 and 2007.

(h) Asset Retirement Obligations
Harvest recognizes the fair value of any asset retirement obligations 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 credit-adjusted risk free discount rate to estimate this fair value. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and depleted and depreciated using the method described under "Property, Plant and Equipment". Subsequent to the initial measurement of the asset retirement obligation, the obligation is adjusted at the end of each subsequent period to reflect the passage of time and changes in the timing and amount of estimated future cash flows underlying the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

(i) Income Taxes

Under the Income Tax Act (Canada) the Trust and its trust subsidiary entities are taxable only on income that is not distributed or distributable to their Unitholders. As both the Trust and its Trust subsidiaries distribute all of their taxable income to their respective Unitholders pursuant to the requirements of their trust indentures, neither the Trust nor its trust subsidiaries are currently subject to income tax. However, pursuant to legislation enacted in 2007, the Trust and its flow-through subsidiaries will become subject to a distribution tax beginning in 2011, provided that Harvest maintains its current structure. Commencing in June 2007, Harvest now provides for future income taxes to reflect this new legislation.

Harvest follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the corporate subsidiaries and their respective tax bases, using enacted or substantively enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. A valuation allowance is recorded against any future income tax asset if it is more likely than not that the asset will not be realized.

(j) Unit-based Compensation

Harvest determines compensation expense for the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan by estimating the intrinsic value of the awards at each period end and recognizing the amount in income over the vesting period. After the awards have vested, further changes in the intrinsic value are recognized in income in the period of change.

The intrinsic value is the difference between the market value of the Units and the exercise price of the right in the case of the Trust Unit Rights Incentive Plan, and in the case of the Unit Award Incentive Plan the market value of the Units represents the intrinsic value of the Award. Under the Trust Unit Rights Incentive Plan, the intrinsic value method is used as participants in the plan have the option to either purchase the Units at the exercise price or to receive a cash payment or Trust Unit equivalent, equal to the excess of the market value of the Units over the exercise price. Under the Unit Award Incentive Plan participants have the option upon exercise to receive a cash payment or Trust Unit equivalent, equal to the value of awards outstanding, which is equivalent to the market value of the Units.

(l) Employee Future Benefits

North Atlantic 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 benefits and other post-retirement benefits is actuarially determined based upon an independent actuarial valuation using 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. The cost of pensions earned by employees is actuarially determined using the projected benefit method prorated on credited service. Funding of the defined benefit pension plans complies with Canadian federal and provincial regulations, and requires contributions to the plans be made based on independent actuarial valuation. 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. For the purpose of calculating the expected return on assets, the fair value of the plan assets is used.

The defined benefit plans provide benefits based on length of service and the best five years of the last ten years' average earnings. There is no recognition or amortization of actuarial gains or losses less than 10% of the greater of the accrued benefit obligations and the fair value of plan assets for the defined benefit pension plans. Actuarial gains and losses over 10% are amortized on a straight-line basis over the average remaining service period of the plan participants. Actuarial gains or losses related to the other post-retirements benefits are recognized in income immediately. Past service costs are amortized on a straight-line basis over the expected average remaining service life of plan participants.

(m) Currency Translation

Monetary assets and liabilities denominated in a currency other than Canadian dollars are translated at the rate of exchange in effect at the balance sheet date. Revenues and expenses denominated in a foreign currency are translated at the monthly average rate of exchange. Translation gains and losses are included in income in the period in which they arise.

Harvest's investment in its downstream operations, which is considered a self-sustaining operation with a U.S. dollar denominated functional currency, is translated using the current rate method. Gains and losses resulting from this translation are recorded in the cumulative translation adjustment in accumulated other comprehensive income.

3. Change in Accounting Policy

Financial Instruments and Comprehensive Income

Effective January 1, 2007, Harvest adopted three new and revised Canadian accounting standards as issued by the Canadian Institute of Chartered Accountants respecting “Financial Instruments – Recognition and Measurement”, “Financial Instruments – Presentation and Disclosure” and “Comprehensive Income”.

Financial Instruments

The revised standard on financial instruments provides new guidance on how to recognize and measure financial instruments. It requires all financial instruments to be recorded at fair value when initially recognized. Subsequent measurement is either at fair value or amortized cost, depending on the classification of the financial instrument. Financial assets and liabilities that are held-for-trading are measured at fair value with changes in those fair values recognized in net income. Available-for-sale financial assets are measured at fair value with unrealized gains or losses recognized in other comprehensive income. Held-to-maturity assets, loans and receivables and other liabilities are all measured at amortized cost with any related expenses or income recognized in net income. Price risk management contracts are classified as held-for-trading and are measured at fair value at initial recognition and at subsequent measurement dates. Any derivatives embedded in other financial or non-financial contracts that were entered into on or after January 1, 2001 must also be measured at fair value and recorded in the financial statements if the embedded derivative is not closely related to the host contract. Fair value of financial instruments is based on market prices where available, otherwise it is calculated as the net present value of expected future cash flows. For those items measured at amortized cost, interest expense is calculated using an effective interest rate that accretes any discount or premium over the life of the instrument so that the carrying value equals the face value at maturity.

Harvest does not have any financial assets classified as available-for-sale or held-to-maturity. The only items on Harvest’s balance sheet that are classified as held-for-trading and subsequently measured at fair value are cash and our price risk management contracts. The remainder of the financial instruments are measured at amortized cost. There are no significant embedded derivatives that need to be recorded in the financial statements.

Transaction costs relating to financial instruments classified as held for trading are expensed in net income in the period that they are incurred. Harvest has elected to add all other transaction costs that are directly attributable to the acquisition or issue of a financial asset or liability to the amount of the financial asset or liability that is recorded on initial recognition.

The transitional provisions of the financial instruments standard require retrospective adoption without restatement of prior period financial statements. The provisions also require all financial instruments to be remeasured using the criteria of the new standard and any change in the previous carrying amount to be recognized as an adjustment to retained earnings on January 1, 2007. As our price risk management contracts were already measured at fair value, the most significant change for Harvest was reclassifying the deferred charges relating to our Senior Notes and Convertible Debentures and netting these amounts against the respective liability. These charges are then amortized to income using an effective interest rate. The effect of applying this new standard on January 1, 2007 was to reduce the carrying value of the following accounts as indicated with an offsetting reduction to deferred charges:

Deferred charges	$	(25,067)
7 $^{7/8}$% Senior Notes		(9,522)
Convertible debentures		(16,882)
Unitholders’ capital		(49)
Accumulated income		1,386

See Note 20 for the additional presentation and disclosure requirements for Financial Instruments including those required for 2008 by Sections 3862 and 3863 as issued by the Canadian Institute of Chartered Accountants.

Other Comprehensive Income

The new standards introduce the concept of comprehensive income, which consists of net income and other comprehensive income. Other comprehensive income represents changes in Unitholders’ equity during a period arising from transactions and other events with non-owner sources. The transitional provisions of this section require that the comparative statements are restated to reflect the application of this standard only on certain items.

For Harvest, the only such item is the unrealized currency translation gains or losses arising from our downstream operations, which is considered a self-sustaining operation with a U.S. dollar functional currency. As the cumulative translation adjustment was presented as a separate component of Unitholders' equity already, this restatement simply required the cumulative translation adjustment to be reclassified to accumulated other comprehensive income on the balance sheet and statement of Unitholders' equity.

Capital Disclosures
"Capital Disclosures", section 1535, requires the disclosure of information about an entity's objectives, policies and processes for managing capital; quantitative data about what the entity regards as capital; whether the entity has complied with externally imposed capital requirements; and if it has not complied, the consequences of such non-compliance.

Inventories
Effective January 1, 2008, Harvest adopted the accounting standard "Inventories", section 3031. This standard provides additional guidance with respect to the measurement and disclosure requirements for inventories, requiring inventories to be valued at the lower of cost and net realizable value. The adoption of this section did not have a material impact on our financial statements.

Future Accounting Changes
In February 2008, the CICA issued section 3064, "Goodwill and Intangible Assets", replacing section 3062 "Goodwill and Other Intangible Assets" and section 3450, "Research and Development Costs". The new section will be effective on January 1, 2009. Section 3062 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous section 3062. We do not expect that the adoption of this standard will have a material impact on our Consolidated Financial Statements.

Convergence of Canadian GAAP with International Financial Reporting Standards
In early 2008, Canada's Accounting Standards Board ("AcSB") announced that Canadian public reporting issuers will be required to report under International Financial Reporting Standards ("IFRS") beginning January 1, 2011. As Harvest will require a full year of comparative disclosures to be compliant with IFRS, all IFRS accounting policies and procedures will be effective on January 1, 2010. Harvest will be required to report under current Canadian GAAP standards through to December 31, 2010.

4. Acquisitions

(a) Private petroleum and natural gas corporation

On July 24, 2008, Harvest acquired all of the issued and outstanding shares of a private petroleum and natural gas corporation for $36.8 million in cash net of working capital adjustments and transaction costs. The purchase price was assigned primarily to oil and gas properties. The results of operations of this acquisition have been included in the consolidated financial statements since its acquisition date.

(b) Petroleum and natural gas assets

On September 8, 2008, Harvest acquired certain petroleum and natural gas assets in exchange for $130.8 million in cash plus an interest in two non-operated properties for total consideration of $136.3 million. The results of operations of these assets have been included in the consolidated financial statements since the acquisition date.

(c) Grand Petroleum Inc. ("Grand")

Pursuant to its cash offer of $3.84 for each issued and outstanding common share of Grand, Harvest acquired control of Grand with its acquisition of 21,310,419 Grand common shares for cash consideration of $81.8 million on July 26, 2007. Subsequent to this acquisition of 74.6% of the issued and outstanding common shares of Grand, Harvest acquired the remaining 7,251,604 common shares of Grand for an additional $27.8 million by extending its offer to purchase to August 9, 2007 and thereafter pursuant to the compulsory acquisition provisions of the *Business Corporations Act (Alberta)*. The aggregate consideration for the Grand acquisition consists of the following:

		Amount
Cash paid	$	109,678
Assumption of bank debt		28,798
Acquisition costs		785
	$	139,261

This acquisition has been accounted for using the purchase method, whereby the assets acquired and the liabilities assumed are recorded at their fair values with the excess of the aggregate consideration over the fair value of the identifiable net assets allocated to goodwill. As of the acquisition date, Grand's operating results have been included in Harvest's revenues, expenses and capital spending. The following summarizes the allocation of the aggregate consideration for the Grand acquisition.

		Amount
Net working capital	$	(3,451)
Property, plant and equipment		147,420
Goodwill		20,546
Asset retirement obligation		(4,416)
Future income tax		(20,838)
	$	139,261

(d) Private petroleum and natural gas corporation

On March 1, 2007, Harvest acquired all of the issued and outstanding shares of a private petroleum and natural gas corporation for $30.6 million net of working capital adjustments and transaction costs. The purchase price was assigned primarily to oil and gas properties. The results of operations of this acquisition have been included in the consolidated financial statements since its acquisition date. An officer of Harvest was a director of this private corporation and received proceeds that are considered to be insignificant to both the officer and Harvest.

5. Inventories

		December 31, 2008		December 31, 2007
Petroleum products				
Upstream – pipeline fill	**$**	**603**	$	564
Downstream		**50,311**		54,472
		50,914		55,036
Parts and supplies		**4,874**		3,898
Total inventories	**$**	**55,788**	$	58,934

During the year ended December 31, 2008, Harvest recognized $35.3 million (2007 – nil) of inventory impairments in its downstream operations. At December 31, 2008, inventories held at net realizable value totaled $37.6 million (December 31, 2007 – $2.2 million).

6. Property, Plant and Equipment

	December 31, 2008			December 31, 2007		
	Upstream	**Downstream**	**Total**	Upstream	Downstream	Total
Cost	**$ 4,710,725**	**$ 1,493,039**	**$ 6,203,764**	$ 4,247,819	$ 1,164,310	$ 5,412,129
Accumulated depletion and depreciation	**(1,572,449)**	**(162,810)**	**(1,735,259)**	(1,142,345)	(72,277)	(1,214,622)
Net book value	**$ 3,138,276**	**$ 1,330,229**	**$ 4,468,505**	$ 3,105,474	$ 1,092,033	$ 4,197,507

General and administrative costs of $10.0 million (2007 – $9.2 million) have been capitalized during the year ended December 31, 2008, of which nil (2007 - $0.6 million) relate to the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan.

All costs, except those associated with major spare parts inventory and assets under construction, are subject to depletion and depreciation at December 31, 2008 including future development costs of $489.5 million (2007 – $325.4 million). Downstream major parts inventory of $7.5 million were excluded from the asset base subject to depreciation at December 31, 2008 (2007 - $6.1 million). Downstream assets under construction of $12.7 million were excluded from the asset base subject to depreciation at December 31, 2008 (2007 - $7.4 million).

The petroleum and natural gas future prices used in the impairment test for petroleum and natural gas assets were obtained from third party engineers and accepted by management. Based on these assumptions, the undiscounted future net revenue from Harvest's proved reserves exceed the carrying amount of its petroleum and natural gas assets as at December 31, 2008 and 2007, and therefore no impairment was recorded in either of the periods ended on these dates.

Benchmark prices and U.S.$/Cdn.$ exchange rate assumptions reflected in the impairment test as at December 31, 2008 were as follows:

Year	WTI Oil[1] (US$/barrel)	Currency Exchange Rate	Edmonton Light Crude Oil[1] (CDN$ barrel)	AECO Gas[1] (CDN$/MMBtu)
2009	60.00	0.85	69.60	7.40
2010	71.40	0.85	83.00	8.00
2011	83.20	0.90	91.40	8.45
2012	90.20	0.95	93.90	8.80
2013	97.40	1.00	96.30	9.05
Thereafter (escalation)	2%	0%	2%	2%

(1) Actual prices used in the impairment test were adjusted for commodity price differentials specific to Harvest.

7. Intangible Assets

	December 31, 2008			December 31, 2007		
	Cost	**Accumulated Amortization**	**Net book value**	Cost	Accumulated Amortization	Net book value
Engineering drawings	**$ 108,402**	**$ (11,969)**	**$ 96,433**	$ 88,227	$ (5,330)	$ 82,897
Marketing contracts	**7,539**	**(2,480)**	**5,059**	6,136	(1,099)	5,037
Customer lists	**4,564**	**(1,008)**	**3,556**	3,714	(449)	3,265
Fair value of office lease	**931**	**(652)**	**279**	931	(428)	503
Financing costs	**7,300**	**(6,625)**	**675**	12,113	(8,740)	3,373
Total	**$ 128,736**	**$ (22,734)**	**$ 106,002**	$ 111,121	$ (16,046)	$ 95,075

8. Accounts Payable and Accrued Liabilities

	December 31, 2008	December 31, 2007
Trade accounts payable	**$ 61,945**	$ 100,265
Accrued interest	**17,262**	15,779
Trust Unit Rights Incentive Plan and Unit Award Incentive Plan *[Note 17]*	**3,894**	7,218
Other accrued liabilities	**126,996**	146,981
Total	**$ 210,097**	$ 270,243

9. Asset Retirement Obligation

Harvest’s asset retirement obligations result from its net ownership interest in petroleum and natural gas assets including well sites, gathering systems and processing facilities and the estimated costs and timing to reclaim and abandon them. Harvest estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations to be approximately $1,203.8 million which will be incurred between 2009 and 2058. The majority of the costs will be incurred between 2015 and 2040. A credit-adjusted risk-free discount rate of 8% - 10% and inflation rate of approximately 2% were used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

	December 31, 2008	December 31, 2007
Balance, beginning of year	**$ 213,529**	$ 202,480
Incurred on acquisition of a private corporation	**1,900**	1,629
Incurred on acquisition of Grand	**-**	4,416
Liabilities incurred	**4,371**	9,553
Revision of estimates	**49,395**	(6,088)
Net liabilities acquired (settled) through acquisition (disposition)	**910**	(3,708)
Liabilities settled	**(11,418)**	(13,090)
Accretion expense	**18,631**	18,337
Balance, end of year	**$ 277,318**	$ 213,529

Harvest has undiscounted asset retirement obligations of approximately $14.9 million relating to the refining and marketing assets. The fair value of this obligation cannot be reasonably determined because the assets currently have an indeterminate life.

10. Bank Loan

Harvest and a syndicate of lenders established a $750 million Three Year Extendible Credit Facility on February 3, 2006 (the "Credit Facility") and on March 31, 2006, completed a secondary syndication and increased the facility to $900 million. Concurrent with the purchase of North Atlantic on October 19, 2006, the facility was further increased to $1.4 billion. During 2007, Harvest and its lenders amended the Credit Facility to increase the aggregate commitment from $1.4 billion to $1.6 billion and extend the maturity date of the facility from March 31, 2009 to April 30, 2010. At December 31, 2008, Harvest had $1,226.2 million drawn of the $1.6 billion available under the Credit Facility ($1,279.5 million drawn at December 31, 2007).

The Credit Facility is secured by a $2.5 billion first floating charge over all of the assets of Harvest's operating subsidiaries plus a first mortgage security interest on the refinery assets of North Atlantic. 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 Unitholders 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 $7^{7/8}$% Senior Notes and Convertible Debentures) to its earnings before interest, taxes, depletion, amortization and other non-cash amounts ("EBITDA"). In addition to the availability under this facility being limited by the Borrowing Base Covenant of the $7^{7/8}$% Senior Notes described (as described in Note 11), availability is subject to the following quarterly financial covenants:

Secured debt to EBITDA	3.0 to 1.0 or less
Total senior debt to EBITDA	3.5 to 1.0 or less
Senior debt to Capitalization	50% or less
Total debt to Capitalization	55% or less

For the year ended December 31, 2008, Harvest's average interest rate on advances under the Credit Facility was 4.12% (2007 – 5.28%) and nil (2007 – 6.08%) for Canadian and U.S advances, respectively.

11. $7^{7/8}$% Senior Notes

On October 14, 2004, Harvest Operations Corp., a wholly owned subsidiary of Harvest, issued US$250 million of $7^{7/8}$% Senior Notes for cash proceeds of $311,951,000. The $7^{7/8}$% Senior Notes are unsecured, require interest payments semi-annually on April 15 and October 15 each year, mature on October 15, 2011 and are unconditionally guaranteed by Harvest and all of its wholly-owned subsidiaries. Prior to maturity, redemptions are permitted as follows:

- After October 15, 2008 at 103.938% of the principal amount
- After October 15, 2009 at 101.969% of the principal amount
- After October 15, 2010 at 100% of the principal amount

The $7^{7/8}$% Senior Notes contains a change of control covenant that requires Harvest Operations Corp. to commence an offer to re-purchase the $7^{7/8}$% Senior Notes at a price of 101% of the principal amount plus accrued interest within 30 days of a change of control event, as defined in the indenture. There are also 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 2.5 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 (as described below) and certain other specific circumstances.

The covenants of the $7^{7/8}$% Senior Notes also restrict Harvest's incurrence of secured indebtedness to an amount less than 65% of the present value of the future net revenues from its proven petroleum and natural gas reserves discounted at an annual rate of 10% (the "Borrowing Base Covenant"). At December 31, 2008, the Borrowing Base Covenant restricts secured indebtedness to Cdn$1.91 billion (at December 31, 2007 - Cdn$1.86 billion).

In addition, the covenants of the $7^{7/8}$% Senior Notes restrict Harvest's ability to pay distributions to Unitholders (net of distributions settled with the delivery of Trust Units) during a quarter to 80% of the prior quarter's cash flow from operating activities before settlement of asset retirement obligations and changes in non-cash working capital if

Harvest's interest coverage ratio as described in the agreement is greater than 2.5 to 1.0 and its consolidated leverage ratio is lower than 3.0 to 1.0. Notwithstanding, distributions are permitted provided that from the date of issuance of the $7^{7/8}$% Senior Notes, the aggregate distributions do not exceed an amount equal to $40 million plus 100% of the net cash proceeds from the sale of Trust Units plus 80% of the cumulative cash flow from operating activities less distributions paid which as at December 31, 2008, amounted to a carry-forward of approximately Cdn$1.5 billion (Cdn$1.5 billion as at December 31, 2007).

The fair value of the $7^{7/8}$% Senior Notes at December 31, 2008 was US$231.4 million (2007 - $232.6 million).

12. Convertible Debentures

Harvest has seven series of convertible unsecured subordinated debentures outstanding (the "Convertible Debentures"). Interest on the debentures is payable semi-annually in arrears in equal installments on dates prescribed by each series. The debentures are convertible into fully paid and non-assessable Trust Units, at the option of the holder, at any time prior to the close of business on the earlier of the maturity date and the business day immediately preceding the date specified by Harvest for redemption. The conversion price per Trust Unit is specified for each series and may be supplemented with a cash payment for accrued interest and in lieu of any fractional Trust Units resulting from the conversion.

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. Any redemption will include accrued and unpaid interest at such time.

Harvest may elect to settle the principal due at maturity or on redemption and periodic interest payments in the form of Trust Units at a price equal to 95% of the weighted average trading price for the preceding 20 consecutive trading days, 5 days prior to settlement date.

The covenants of the Convertible Debentures restrict Harvest's issuance of additional convertible debentures if the principal amount of all of its issued and outstanding convertible debentures immediately after the issuance of such additional convertible debentures exceeds 25% of the Total Market Capitalization, as defined. Total Market Capitalization is defined as the total principal amount of all issued and outstanding convertible debentures plus the amount obtained by multiplying the number of issued and outstanding Trust Units by the current value of the Trust Units. As at December 31, 2008, Harvest's Total Market Capitalization was approximately Cdn$2.6 billion (Cdn$3.8 billion as at December 31, 2007).

The following is a summary of the seven series of convertible debentures:

Series	Conversion price / Trust Unit	Maturity	First redemption period	Second redemption period
9% Debentures Due 2009	$ 13.85	May 31, 2009	Jun. 1/07-May 31/08	Jun. 1/08-May. 30/09
8% Debentures Due 2009	$ 16.07	Sept. 30, 2009	Oct. 1/07-Sept. 30/08	Oct. 1/08-Sept. 29/09
6.5% Debentures Due 2010	$ 31.00	Dec. 31, 2010	Jan. 1/09-Dec. 31/09	Jan. 1/10-Dec. 30/10
6.40% Debentures Due 2012(1)	$ 46.00	Oct. 31, 2012	Nov. 1/08-Oct. 31/09	Nov. 1/09-Oct. 31/10
7.25% Debentures Due 2013(1)	$ 32.20	Sept. 30, 2013	Oct. 1/09-Sept. 30/10	Oct. 1/10-Sept. 30/11
7.25% Debentures Due 2014(1)	$ 27.25	Feb. 28, 2014	Mar. 1/10-Feb. 28/11	Mar. 1/11-Feb. 29/12
7.5% Debentures Due 2015(1)	$ 27.40	May 31, 2015	Jun. 1/11-May 31/12	Jun. 1/12-May 31/13

(1) These series of convertible debentures may also be redeemed by Harvest at a price of $1,000 per debenture after the second redemption period until maturity.

The following table summarizes the face value, carrying amount and fair value of the convertible debentures:

	December 31, 2008			December 31, 2007		
	Face Value	**Carrying Amount(1)**	**Fair Value**	Face Value	Carrying Amount(1)	Fair Value
9% Debentures Due 2009	**$ 944**	**$ 940**	**$ 984**	$ 976	$ 962	$ 1,806
8% Debentures Due 2009	**1,588**	**1,573**	**1,540**	1,728	1,692	2,022
6.5% Debentures Due 2010	**37,062**	**35,387**	**29,650**	37,062	34,653	35,950
10.5% Debentures Due 2008	**-**	**-**	**-**	24,258	24,273	24,258
6.40% Debentures Due 2012	**174,626**	**169,455**	**75,089**	174,626	168,325	148,432
7.25% Debentures Due 2013	**379,256**	**358,533**	**166,835**	379,256	355,145	344,895
7.25% Debentures Due 2014	**73,222**	**67,549**	**36,611**	73,222	66,718	65,892
7.5% Debentures Due 2015	**250,000**	**194,322**	**107,500**	-	-	-
	$ 916,698	**$ 827,759**	**$ 418,209**	$ 691,128	$ 651,768	$ 623,255

(1) Excluding the equity component**.**

On January 31, 2008, the 10.5% Debenture matured and Harvest elected to settle its obligation by issuing 1,166,593 Trust Units rather than settling in cash.

On April 25, 2008, Harvest issued $250 million principal amount of 7.5% Convertible Debentures for total net proceeds from the issue of $239.5 million. These debentures mature on May 31, 2015 and have a conversion price of $27.40.

13. Normal Course Issuer Bid

On October 20, 2008, the Toronto Stock Exchange approved our Normal Course Issuer Bid to purchase for cancellation, subject to daily limits, up to 10% of the outstanding Trust Units and Convertible Debentures not held by insiders on the open market at the prevailing market prices at the time of such purchase. To date, there have been no such purchases.

14. Unitholders' Capital

(a) Authorized

The authorized capital consists of an unlimited number of Trust Units.

(b) Number of Units Issued

	Year ended December 31	
	2008	2007
Outstanding, beginning of year	**148,291,170**	122,096,172
Issued for cash		
February 1, 2007	**-**	6,146,750
June 1, 2007	**-**	7,302,500
Convertible debenture conversions		
9% Debentures Due 2009	**2,310**	18,047
8% Debentures Due 2009	**8,710**	31,790
6.5% Debentures Due 2010	**-**	27,967
10.5% Debentures Due 2008	**344**	81,478
6.40% Debentures Due 2012	**-**	2,542
7.25% Debentures Due 2013	**-**	7,574
7.25% Debentures Due 2014	**-**	5,753,310
Redemption of convertible debentures		
10.5% Debentures Due 2008	**1,166,593**	-
Distribution reinvestment plan issuance	**7,655,414**	6,809,987
Exercise of unit appreciation rights and other	**76,160**	13,053
Outstanding, end of year	**157,200,701**	148,291,170

On August 17, 2005, Harvest implemented a premium distribution reinvestment plan. The premium distribution program enables investors to receive a cash payment equal to 102% of the regular distribution amount. The impact to Harvest is the same as the regular distribution reinvestment plan whereby it settles distributions with Units rather than cash, at a discount to the current market price of the Units at the option of the Unitholder.

(c) Per Trust Unit Information

The following tables summarize the net income and Trust Units used in calculating income per Trust Unit:

Net income adjustments		**December 31, 2008**		December 31, 2007
Net (loss) income, basic	**$**	**212,019**	$	(25,676)
Interest on Convertible Debentures		**95**		-
Net income, diluted[1]	**$**	**212,114**	$	(25,676)

Weighted average Trust Units adjustments	**December 31, 2008**	December 31, 2007
Number of Units		
Weighted average Trust Units outstanding, basic	**152,836,717**	138,440,869
Effect of Convertible Debentures	**69,155**	-
Effect of Employee Unit Incentive Plans	**200,789**	-
Weighted average Trust Units outstanding, diluted[2]	**153,106,661**	138,440,869

(1) Net income, diluted excludes the impact of the conversions of certain of the Convertible Debentures of $69.4 million for the year ended December 31, 2008 (2007 - $59.2 million), as the impact would be anti-dilutive.

(2) Weighted average Trust Units outstanding, diluted for the year ended December 31, 2008 does not include the unit impact of 25,915,000 for certain of the Convertible Debentures (2007 – 23,636,000) and nil (2007 – 682,000) for the Employee Unit Incentive Plans, as the impact would be anti-dilutive.

15. Contributed Surplus

Contributed surplus of $6.4 million has been recorded during the year ended December 31, 2008 due to the maturity of the 10.5% Debentures and the resulting expiration of the conversion option which was previously recorded in equity component of convertible debentures.

16. Capital Structure

Harvest's primary objective in its management of capital resources is to ensure sufficient financial flexibility to access capital to fund its financial obligations as well as future growth. Harvest considers its capital structure to comprise its credit facilities, $7^{7/8}$% Senior Notes, Convertible Debentures and unitholders' equity.

Harvest monitors its capital structure using the following non-GAAP financial ratios: bank debt to Twelve Month Trailing Earnings Before Interest, Taxes, Depreciation and Amortization and non-cash amounts ("EBITDA"), secured debt to net present value of our proved petroleum and natural gas reverses discounted at 10% and total debt to total debt plus unitholders' equity. Total debt includes borrowings under credit facilities plus our $7^{7/8}$% Senior Notes and principal amount of Convertible Debentures and unitholders' equity is adjusted to remove the equity component of convertible debentures.

Harvest's capital management strategy with regards to our bank debt is to maintain a bank debt to EBITDA ratio between 1.0 and 2.5 times. This ratio is calculated as follows:

		December 31, 2008		December 31, 2007
Cash provided by operating activities	**$**	**655,887**	$	641,313
Settlement of asset retirement obligations		**11,418**		13,090
Change in non-cash working capital		**9,897**		17,384
Interest paid		**132,473**		145,742
Large Corporations Tax and other taxes paid		**(81)**		(974)
Total EBITDA	**$**	**809,594**	$	816,555
Bank debt	**$**	**1,226,228**	$	1,279,501
Bank debt to EBITDA		**1.51**		1.57

With respect to its secured debt, Harvest's strategy is to target its secured debt to less than 65% of the net present value of its proved petroleum and natural gas reserves discounted at 10% (as determined on an annual basis) by at least $200 million.

	December 31, 2008	December 31, 2007
Proved petroleum and natural gas reserves (Net Present Value discounted at 10%)	**$ 2,941,452**	$ 2,865,200
65% of Proved petroleum and natural gas reserves	**$ 1,911,944**	$ 1,862,380
Secured debt (borrowings under Credit Facilities)	**$ 1,226,228**	$ 1,279,501

Harvest targets its total debt to total debt plus unitholders' equity to be a ratio between 0.25 and 0.55 times calculated as follows:

	December 31, 2008	December 31, 2007
Bank debt	**$ 1,226,228**	$ 1,279,501
$7^{7/8}$% Senior Notes (1)	**304,500**	247,825
Principal amount of convertible debentures	**916,698**	691,128
Total Debt	**2,447,426**	2,218,454
Unitholders' equity (less equity component of convertible debentures)	**2,559,229**	2,445,837
Total debt plus unitholders' equity	**$ 5,006,655**	$ 4,664,291
Total debt to total debt plus unitholders' equity	**0.49**	0.48

(1) Face value converted at the year end exchange rate.

Harvest's capital structure is limited by a covenant in its Convertible Debenture Indenture which currently restricts the issuance of additional convertible debentures. In addition, although Harvest's Trust Unit Indenture provides for the issuance of an unlimited number of Trust Units, the "normal growth guidelines" contained in Bill C-52 issued by the Government of Canada limits the future issuance of Convertible Debentures and Trust Units at December 31, 2008 to approximately $2.4 billion (2007 - $2.8 billion) with any unused normal growth available for use prior to 2011. Included in this amount is approximately $590 million (2007 - $590 million) that the Trust may issue to replace debt held on October 31, 2006.

At December 31, 2008, all covenants related to the bank loan (Note 10), Senior Notes (Note 11) and Convertible Debentures (Note 12) were met.

Harvest monitors its capital structure and makes adjustments according to market conditions to remain flexible while meeting its objectives as outlined above. Accordingly, Harvest may adjust its capital spending programs, adjust the amount of distributions paid to Unitholders, issue new Trust Units, Convertible Debentures or Senior Notes or repay existing debt. Harvest's capital management targets have remained unchanged during the year ended December 31, 2008.

17. Employee Unit Incentive Plans

Trust Unit Rights Incentive Plan

Harvest is authorized to grant non-transferable unit appreciation rights to directors, officers, consultants, employees and other service providers to an aggregate of a rolling maximum of 7% of the outstanding Trust Units and the number of Trust Units issuable upon the exchange of any outstanding exchangeable shares. The initial exercise price of rights granted under the plan is equal to the market price of the Trust Units at the time of grant and the maximum term of each right is five years. The rights vest equally over four years commencing on the first anniversary of the grant date. The exercise price of the rights may be reduced by an amount up to the amount of cash distributions made on the Trust Units subsequent to the date of grant of the respective right, provided that Harvest's net operating cash flow (on an annualized basis) exceeds 10% of Harvest's recorded cost of property, plant and equipment less all debt, working capital deficiency (surplus) or debt equivalent instruments, accumulated depletion, depreciation and amortization charges, asset retirement obligations, and any future income tax liability associated with such property, plant and equipment. Any portion of a distribution that does not reduce the exercise price on exercised rights is paid to the holder in a lump sum cash payment after the rights have been exercised.

Upon the exercise of unit appreciation rights the holder has the sole discretion to elect to receive cash or units. As a result, Harvest recognizes a liability on its consolidated balance sheet associated with the rights reserved under the plan. This obligation represents the difference between the market value of the Trust Units and the exercise price of the vested unit rights outstanding under the plan. As such, an obligation of $0.3 million (2007 - $1.4 million) has been recorded in accounts payable and accrued liabilities for the graded vested portion of the 8,037,446 (2007 – 3,823,683) Trust Unit Rights outstanding under the plan at December 31, 2008. For accounting purposes, vesting is deemed to occur on a pro rata basis throughout the year, rather than at a vesting date which only occurs on the anniversary date of the grant.

The following summarizes the Trust Units reserved for issuance under the Trust Unit Rights Incentive Plan:

	Year ended December 31, 2008		Year ended December 31, 2007	
	Unit Appreciation Rights	**Weighted Average Exercise Price**	Unit Appreciation Rights	Weighted Average Exercise Price
Outstanding beginning of year	**3,823,683**	**$ 30.74**	3,788,125	$ 30.81
Granted	**5,244,102**	**15.68**	576,383	29.03
Exercised	**(68,675)**	**25.67**	(92,775)	21.88
Forfeited	**(961,644)**	**28.80**	(448,050)	31.10
Outstanding before exercise price reductions	**8,037,466**	**21.19**	3,823,683	30.74
Exercise price reductions	**-**	**(4.45)**	-	(6.11)
Outstanding, end of year	**8,037,466**	**16.74**	3,823,683	$ 24.63
Exercisable before exercise price reductions	**85,200**	**$ 22.60**	145,950	$ 23.08
Exercise price reductions	**-**	**(15.49)**	-	(12.17)
Exercisable, end of year	**85,200**	**$ 7.11**	145,950	$ 10.91

The following table summarizes information about Unit appreciation rights outstanding at December 31, 2008.

		Outstanding			**Exercisable**	
Exercise Price before price reductions	**Exercise Price net of price reductions**	**At December 31, 2008**	**Weighted Average Exercise Price net of price reductions(1)**	**Remaining Contractual Life (1)**	**At December 31, 2008**	**Weighted Average Exercise Price net of price reductions(1)**
$10.39-$12.51	$9.49-$12.21	3,185,230	$ 10.38	5.0	-	$ -
$14.99-$18.90	$0.01-$17.73	50,600	10.93	3.2	18,750	0.29
$19.29-$25.37	$4.87-$23.48	1,894,053	19.96	4.1	66,450	9.03
$26.09-$31.96	$15.23-$25.55	1,527,033	18.73	3.0	-	-
$32.01-$37.56	$19.13-$28.79	1,380,550	24.99	2.3	-	-
$10.39-$37.56	$0.01-$28.79	8,037,466	$ 16.74	3.9	85,200	$ 7.11

(1) Based on weighted average Unit appreciation rights outstanding.

Unit Award Incentive Plan ("Unit Award Plan")
The Unit Award Plan authorizes Harvest to grant awards of Trust Units to directors, officers, employees and consultants of Harvest and its affiliates to an aggregate of a rolling maximum of 0.5% of the outstanding Trust Units and the number of Trust Units issuable upon the exercise of any outstanding exchangeable shares. Subject to the Board of Directors' discretion, awards vest annually over a two to four year period and, upon vesting, entitle the holder to elect to receive the number of Trust Units subject to the award or the equivalent cash amount. The number of Units to be issued is adjusted at each distribution date for an amount approximately equal to the foregone distributions. Harvest recognizes a liability on its consolidated balance sheet associated with the awards granted under the plan. This obligation represents the fair value of the vested Trust Units granted under the Unit Award Plan. As such, an obligation of $3.6 million (2007 - $5.8 million) has been recorded in accounts payable and accrued liabilities for the graded vested portion of the 659,137 (2007 – 348,248) Unit Awards outstanding under the plan at December 31, 2008. For accounting purposes, vesting is deemed to occur on a pro rata basis throughout the year, rather than at a vesting date.

Number	**December 31, 2008**	December 31, 2007
Outstanding, beginning of year	**348,248**	306,699
Granted	**390,274**	56,132
Adjusted for distributions	**75,310**	48,280
Exercised	**(121,776)**	(37,072)
Forfeitures	**(32,919)**	(25,791)
Outstanding, end of year	**659,137**	348,248
Exercisable, end of year	**238,817**	168,401

Harvest has recognized a compensation recovery of $0.7 million (2007 – $2.7 million expense), including a non cash compensation recovery of $1.7 million (2007 – $0.6 million expense), for the year ended December 31, 2008, related to the Trust Unit Rights Incentive Plan and the Unit Award Plan and this is reflected in general and administrative expense in the consolidated statements of income.

18. Income Taxes

The future income tax provision reflects the net tax effects of temporary differences between the carrying amounts of assets and liabilities of the Trust and their corresponding income tax bases as at that date. Changes in the temporary differences are reflected in future income tax expense.

In the Second Quarter of 2007, the Canadian government enacted legislation to apply a 31.5% tax to distributions from Canadian publicly traded income trusts. In the Fourth Quarter of 2007, the tax rate for trust distributions was reduced to 29.5% for 2011 and to 28% for 2012 and subsequent years. The new tax is not expected to apply to Harvest until 2011, as a transition period has been established for publicly traded trusts that existed prior to November 1, 2006. This portion of the Trust's future income tax liability represents its tax-effected portion of December 31, 2008 temporary differences that it estimates will exist on January 1, 2011, pursuant to the current legislation and Harvest's current structure.

Concurrent with the tax rate reductions referred to above, further reductions in Federal corporate income tax rates were enacted. Under the legislation, Federal corporate rates will decline until 2012, resulting in an effective tax rate for the Trust's corporate entities of approximately 25%, which is the rate applied to the temporary differences in the future income tax calculation based on when these differences are expected to reverse.

The provision for future income taxes varies from the amount that would be computed by applying the relevant Canadian income tax rates to reported income before taxes as follows:

		Year ended December 31		
		2008		2007
Income before taxes	**$**	**320,498**	$	39,152
Combined Canadian Federal and Provincial statutory income tax rate		**29.85%**		32.70%
Computed income tax expense at statutory rates		**95,669**		12,803
Income earned by flow through entities		**(109,335)**		(179,750)
Expected tax expense (recovery) in corporate entities		**(13,666)**		(166,947)
Increased expense (recovery) resulting from the following:				
Temporary differences acquired in excess of fair value limitation		**944**		-
Initial recognition of trust temporary differences		**-**		271,705
Benefit of future tax deductions previously unrecognized		**-**		(72,073)
Difference between current and expected tax rates		**113,655**		44,547
Non-taxable portion of capital (gain) loss		**8,216**		(20,515)
Change in estimates of future temporary differences		**(1,231)**		8,860
Non-deductible expenses		**642**		225
Future income tax expense		**108,560**		65,802

The components of the future income tax liability are as follows:

		December 31, 2008		December 31, 2007
Net book value of petroleum and natural gas assets in excess of tax pools	$	**498,725**	$	333,466
Net book value of intangible assets in excess of tax pools		**16,640**		13,998
Asset retirement obligation		**(73,899)**		(56,066)
Net unrealized losses related to risk management contracts and currency exchange positions – current		**7,124**		(38,642)
Net unrealized losses related to risk management contracts and currency exchange positions – long-term		**1,177**		304
Non-capital loss carry forwards for tax purposes		**(241,660)**		(161,706)
Deferral of taxable income in partnership		**554**		1,492
Future employee retirement costs		**(3,135)**		(3,607)
Working capital and other items		**(1,528)**		(2,599)
Future income tax liability (asset), net	$	**203,998**	$	86,640

The expiry dates on the consolidated non-capital losses are as follows:

Year of Expiry	
2009	**$ 12,667**
2013	**9,768**
2014	**40,110**
2025	**97,300**
2026	**40,958**
2027	**455,729**
2028	**342,423**
Consolidated non-capital losses	**$ 998,955**

See Commitments, Contingencies and Guarantees [Note 22(f)].

19. Employee Future Benefit Plans

Defined Benefit Plans
The measurement of the accrued benefit obligation and annual expense for the defined benefit plans requires actuarial calculations and several assumptions. These assumptions, set annually on December 31, are as follows:

	December 31, 2008		**December 31, 2007**	
	Pension Plans	**Other Benefit Plans**	**Pension Plans**	**Other Benefit Plans**
Discount rate	**7.25%**	**7.25 %**	**5.0%**	**5.0 %**
Expected long-term rate of return on plan assets	**7.0%**	**-**	**7.0%**	**-**
Rate of compensation increase	**3.5%**	**-**	**3.5%**	**-**
Employee contribution of pensionable income	**6.0%**	**-**	**6.0%**	**-**
Annual rate of increase in covered health care benefits	**-**	**10%**	**-**	**11%**
Expected average remaining service lifetime (years)	**11.7**	**10.7**	**11.7**	**10.8**

The assets of the defined benefit plan are invested and maintain the following asset mix:

	December 31, 2008	**December 31, 2007**
Bonds/fixed income securities	**36%**	**32%**
Equity securities	**64%**	**68%**

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 pension plans were subject to an actuarial valuation on December 31, 2008 and the next valuation report is due no later than December 31, 2011. The post-retirement health care benefits plan was last subject to an actuarial valuation on December 31, 2008.

	December 31, 2008		December 31, 2007	
	Pension Plans	**Other Benefit Plans**	**Pension Plans**	**Other Benefit Plans**
Employee benefit obligation, beginning of year	**$ 49,082**	**$ 6,653**	**$ 43,101**	**$ 6,027**
Current service costs	**3,355**	**370**	**3,043**	**369**
Interest	**2,673**	**346**	**2,357**	**316**
Actuarial losses (gains)	**(13,086)**	**(1,795)**	**1,409**	**162**
Benefits paid	**(1,372)**	**(276)**	**(828)**	**(221)**
Employee benefit obligation, end of year	**40,652**	**5,298**	**49,082**	**6,653**
Fair value of plan assets, beginning of year	**38,903**	**-**	**36,576**	**-**
Actual return on plan assets	**(7,587)**	**-**	**(1,682)**	**-**
Employer contributions	**3,485**	**199**	**3,428**	**221**
Employee contributions	**1,703**	**77**	**1,409**	**-**
Benefits paid	**(1,372)**	**(276)**	**(828)**	**(221)**
Fair value of plan assets, end of year	**35,132**	**-**	**38,903**	**-**
Funded status	**(5,520)**	**(5,298)**	**(10,179)**	**(6,653)**
Unamortized balances:				
Net actuarial losses	**267**	**-**	**4,664**	**-**
Carrying amount	**$ (5,253)**	**$ (5,298)**	**$ (5,515)**	**$ (6,653)**

	December, 31, 2008	December 31, 2007
Summary:		
Pension plans	**$ 5,253**	$ 5,515
Other benefit plans	**5,298**	6,653
Carrying amount	**$ 10,551**	$ 12,168

Estimated pension and other benefit payments to plan participants which reflect expected future service, expected to be paid from 2009 to 2018, are as follows:

	Pension Plans	**Other Benefit Plans**
2009	**$ 1,394**	**$ 333**
2010	**1,640**	**468**
2011	**1,875**	**561**
2012	**2,143**	**686**
2013	**2,457**	**828**
2014 to 2018	**19,547**	**6,790**
Total	**$ 29,056**	**$ 9,666**

The table below shows the components of the net benefit plan expense:

	Year ended December 31, 2008		Year ended December 31, 2007	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Current service cost	**$ 3,355**	**$ 370**	$ 3,043	$ 369
Interest costs	**2,673**	**346**	2,357	316
Expected return on assets	**(2,806)**	**-**	(2,657)	-
Amortization of net actuarial losses	**-**	**(1,872)**	-	101
Net benefit plan expense	**$ 3,222**	**$ (1,156)**	$ 2,743	$ 786

A 1% change in the expected health care cost trend rate would have the following annual impacts as at December 31, 2008:

	1% Increase	1% Decrease
Impact on post-retirement benefit expense	$ 1	$ (1)
Impact on projected benefit obligation	13	(20)

20. Financial Instruments and risk management contracts

Financial instruments of Harvest consist of cash, accounts receivable, accounts payable and accrued liabilities, cash distribution payable, bank loan, risk management contracts, Convertible Debentures and the $7^{7/8}$% Senior Notes. The carrying value and fair value of these financial instruments at December 31, 2008 is disclosed below by financial instrument category, as well as any related gains or losses and interest income or expense for the year ended December 31, 2008:

	Carrying Value	Fair Value	Gains/ (Losses)	Interest Income/ (Expense)	Other Income/ (Expense)
Loans and Receivables					
Accounts receivable	$ 173,341	$ 173,341	$ -	$ 329 [(2)]	$ -
Assets Held for Trading					
Net fair value of risk management contracts	35,852	35,852	(14,861) [(3)]	-	-
Other Liabilities					
Accounts payable	210,097	210,097	-	-	-
Cash distribution payable	47,160	47,160	-	-	-
Bank loan	1,226,228	1,226,228	-	(51,855) [(4)]	(2,699) [(4)]
$7^{7/8}$% Senior Notes	298,210 [(1)]	231,420	-	(22,662) [(5)]	-
Convertible Debentures	$ 827,759	$ 418,209	$ -	$ (69,454) [(5)]	$ -

(1) The face value of the $7^{7/8}$% Senior Notes at December 31, 2008 is $304.5 million (U.S. $250 million).
(2) Included in petroleum, natural gas, and refined product sales in the statement of income and comprehensive income.
(3) Included in risk management contracts - realized and unrealized gains (losses) in the statement of income and comprehensive income.
(4) Included in interest and other financing charges on short term/long term debt in the statement of income and comprehensive income. The amortization of financing fees related to this liability is included in amortization of deferred finance charges in the statement of cash flows.
(5) Included in interest and other financing charges on short term/long term debt in the statement of income and comprehensive income. The non-cash interest expense relating to the accretion of premiums, discounts or transaction costs that are netted against these liabilities are included in non-cash interest in the statement of cash flows.

The fair values of the Convertible Debentures and the $7^{7/8}$% Senior Notes are based on quoted market prices as at December 31, 2008. The risk management contracts are recorded on the balance sheet at their fair value; accordingly, there is no difference between fair value and carrying value. The bank loan is recorded at amortized cost, but as there are no transaction costs associated with our bank debt and the financing costs are included in intangible assets, there is no difference between the carrying value and the fair value. Due to the short term nature of accounts receivable, accounts payable, cash distribution payable and the bank loan, their carrying values approximate their fair values.

(a) 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 and counterparties to price risk management contracts and to liquidity risk relating to our debt.

(i.) Credit Risk

Upstream Accounts Receivable

Accounts receivable in our 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 also exposed to credit risk from the counterparties to our risk management contracts. This risk is managed by diversifying Harvest's risk management portfolio among a number of counterparties and limiting those counterparties to lenders in our syndicated credit facilities; we have no history of impairment with these counterparties.

Downstream Accounts Receivable

The Supply and Offtake Agreement entered into in conjunction with the purchase of the downstream operations exposed Harvest to the credit risk of Vitol Refining S.A. ("Vitol") as all feedstock purchases and the majority of product sales are made with Vitol under this agreement. Harvest mitigates this risk by requiring that Vitol maintain a minimum B+ credit rating as assessed by Standard and Poor's Rating Services. If the credit rating falls below this line, additional security is required to be supplied to Harvest. This credit risk is also mitigated by the amounts owing to Vitol for feedstock purchases that are offset against amounts receivable from Vitol for product sales with the balance being net settled. Harvest is in a net payable position with Vitol at December 31, 2008 and accordingly the outstanding balance is included in current trade accounts payable in the liability liquidity table below.

Harvest's policy is to manage its credit risk by dealing with only financially sound customers, based on an evaluation of the customer's financial condition. At December 31, 2008, Harvest had an accounts receivable balance with one customer of $5.1 million resulting from the sale of refined product, representing approximately 8% of total downstream accounts receivable. This customer is an integrated multinational energy company with an AA public credit rating.

Our maximum exposure to credit risk relating to the above classes of financial assets at December 31, 2008 is the carrying value of accounts receivable. The table below provides an analysis of our current financial assets and the age of our past due but not impaired financial assets by type of credit risk.

	Current AR	**Overdue AR**			
		≤ 30 days	**> 30 days, ≤ 60 days**	**> 60 days, ≤ 90 days**	**> 90 days**
Upstream Accounts Receivable	$ 79,112	$ 1,260	$ 2,498	$ 1,256	$ 20,908
Risk Management Contract Counterparties	825	-	-	-	-
Downstream Accounts Receivable	59,982	3,094	800	510	3,096
Total	**$ 139,919**	**$ 4,354**	**$ 3,298**	**$ 1,766**	**$ 24,004**

(ii.) Liquidity Risk

Harvest is exposed to liquidity risk due to our borrowings under our credit facilities and $7^{7/8}$% Senior Notes with repayment requirements. This risk is mitigated by managing the maturity dates on our obligations, complying with covenants and managing our cash flow by entering into price risk management contracts. Additionally, when we enter into price risk management contracts we select counterparties that are also lenders in our syndicated credit facility thereby using the security provided in our credit agreement eliminating the requirement for margin calls and the pledging of collateral.

The following table provides an analysis of our financial liability maturities based on the remaining terms of our liabilities as at December 31, 2008 and includes the related interest charges:

	≤1 year	**>1 year ≤3 years**	**>4 years ≤5 years**	**>5 years**	**Total**
Trade accounts payable and accrued liabilities	$ 188,941	$ -	$ -	$ -	$ 188,941
Distributions payable	47,160	-	-	-	47,160
Bank loan and interest	28,632	1,235,563	-	-	1,264,195
Convertible debentures interest[1]	65,269	127,864	105,386	27,300	325,819
$7^{7/8}$% Senior Notes and interest	23,979	347,334	-	-	371,313
Pension contributions	6,900	14,217	14,791	7,618	43,526
Asset retirement obligations	14,214	30,790	26,958	1,131,823	1,203,785
Total	**$ 375,095**	**$1,755,768**	**$ 147,135**	**$1,166,741**	**$3,444,739**

(1) Convertible Debentures are typically converted into Trust Units prior to maturity or are redeemed for Trust Units at maturity by Harvest; therefore, only the interest portion is represented in the table above. At the Trust's option, the interest on Convertible Debentures may also be settled in Trust Units.

(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.

We have performed sensitivity analysis on the three types of market risks identified, assuming that the volatility of the risks over the next quarter 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 12 months of data, we factor in the seasonality of our business and the price volatility therein.

Interest rate risk

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 our secured debt to EBITDA. Harvest's Convertible Debentures and $7^{7/8}$% 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.

For the year ended December 31, 2008, interest charges on bank loans aggregated to $49.6 million (2007 - $43.8 million), reflecting an effective interest rate of 4.12% (2007 – 5.28%).

At December 31, 2008, if interest rates had decreased by 70% with all other variables held constant, after-tax net income for the year would have been $12.8 million higher, as a result of lower interest expense on variable rate borrowings. If interest rates had increased by 70%, with all other variables held constant, the after-tax net income would have been $12.8 million lower.

Currency exchange rate risk

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 $7^{7/8}$% Senior Notes are denominated in U.S. dollars (U.S.$250 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 is also exposed to currency exchange rate risk on its net investment in our downstream operations which is a self sustaining subsidiary that uses a U.S. dollar functional currency. 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, 2008, 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:

	Impact on Net Income	
U.S. Dollar Exchange Rate - 8% increase	$	(24,249)
U.S. Dollar Exchange Rate - 8% decrease	$	24,249

As mentioned above, Harvest's downstream operations operates with a U.S. dollar functional currency which gives rise to currency exchange rate risk on North Atlantic Refining LP's Canadian dollar denominated monetary assets and liabilities, such as Canadian dollar bank accounts and accounts receivable and payable, as follows:

	Impact on Net Income	
Canadian Dollar Exchange Rate - 8% increase	$	(20,503)
Canadian Dollar Exchange Rate - 8% decrease	$	20,503

Commodity Price Risk

Harvest uses price risk management contracts to manage a portion of its crude oil, natural gas and refined product sales price exposure and power costs. These contracts are recorded on the balance sheet at their fair value as of the balance sheet date, with changes from the prior period's fair value reported in net income for the period. These fair values are generally determined as the difference between the stated fixed price of the contract and an expected future price of the underlying asset. Variances in expected future prices expose us to commodity price risk as changes will result in a gain or loss that we 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 in place at December 31, 2008, net income would be impacted as follows:

		Impact on NI			
Contract	**% Change**	**Due to % increase**		**Due to % decrease**	
Heating Oil NYMEX	65%	$	(50,678)	$	-
#6 (1%) HFO Platts	75%		(13,457)		-
Total		**$**	**(64,135)**	**$**	**-**

(b) Fair Values

At December 31, 2008, the net fair value reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $35.9 million (2007 - $149.7 million deficiency), which was included in the balance sheet as follows: fair value of risk management contracts (current assets) $36.1 million, fair value deficiency of risk management contracts (current liabilities) $0.2 million.

The following is a summary of Harvest's risk management contracts outstanding, along with their fair value at December 31, 2008:

Quantity	Type of Contract	Term	Average Price		Fair value
Refined Product Price Risk Management					
12,000 bbl/d	NYMEX heating oil 3-way contract	Jan. 09 – Jun. 09	US$72.59 - $98.73 ($86.52)[(a) (c)]	$	26,808
8,000 bbl/d	Platt's fuel oil 3-way contract	Jan. 09 – Jun. 09	US$49.75 - $65.89 ($57.38)[(b)]		9,279
					$36,087
Natural Gas Price Risk Management					
251 GJ/d	Fixed price – natural gas contract	Jan. 09 – Dec. 09	Cdn$3.48[(d)]	$	**(235)**
Total net fair value of risk management contracts				**$**	**35,852**

(a) If the market price is below the floor price of $72.59, price received is market price plus $13.93; if the market price is between the floor price of $72.59 and $86.52, the price received is $86.52; if the market price is between $86.52 and the ceiling of $98.73, the price received is market price; if the market price is over the ceiling of $98.73, price received is $98.73.

(b) If the market price is below the floor of $49.75, price received is market price plus $7.63; if the market price is between the floor price of $49.75 and $57.38, the price received is $57.38; if the market price is between $57.38 and the ceiling of $65.89, the price received is market price; if the market price is over the ceiling of $65.89, price received is $65.89.

(c) Heating oil contracts are contracted in U.S. dollars per U.S. gallon and are presented in this table in U.S. dollars per barrel for comparative purposes (1 barrel equals 42 U.S. gallons).

(d) This contract contains an annual escalation factor such that the fixed price is adjusted each year.

For the year ended December 31, 2008, the total unrealized gain recognized in the consolidated statement of income and comprehensive income was $185.9 million (2007 - a loss of $147.8 million), which represents the change in fair value of financial assets and liabilities classified as held for trading. The realized gains and losses on all risk management contracts are included in the period in which they are incurred.

21. 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.

Results of Continuing Operations	Downstream[1]		Upstream[1]		Total	
	2008	2007	**2008**	2007	**2008**	2007
Revenue[2]	**$ 4,194,595**	$ 3,098,556	**$ 1,543,214**	$ 1,184,457	**$ 5,737,809**	$ 4,283,013
Royalties	**-**	-	**(248,445)**	(213,413)	**(248,445)**	(213,413)
Less:						
Purchased products for resale and processing	**3,850,507**	2,667,714	**-**	-	**3,850,507**	2,667,714
Operating[3]	**236,259**	229,290	**300,890**	300,918	**537,149**	530,208
Transportation and marketing	**20,753**	34,970	**13,490**	11,946	**34,243**	46,916
General and administrative	**1,875**	1,713	**32,868**	34,615	**34,743**	36,328
Depletion, depreciation, amortization and accretion	**71,076**	72,599	**448,735**	454,142	**519,811**	526,741
	$ 14,125	$ 92,270	**$ 498,786**	$ 169,423	**512,911**	261,693
Realized net losses on risk management contracts					**(200,782)**	(26,291)
Unrealized net gains (losses) on risk management contracts					**185,921**	(147,781)
Interest and other financing charges on short term debt					**(295)**	(5,584)
Interest and other financing charges on long term debt					**(146,375)**	(152,201)
Currency exchange gain (loss)					**(30,882)**	109,316
Large corporations tax recovery and other tax					**81**	974
Future income tax					**(108,560)**	(65,802)
Net (loss) income					**$ 212,019**	$ (25,676)
Total Assets[4]	**$ 1,775,688**	$ 1,482,904	**$ 3,933,632**	$ 3,952,337	**$ 5,745,407**	$ 5,451,683
Capital Expenditures						
Development and other activity	**$ 56,162**	$ 44,111	**$ 271,312**	$ 300,674	**$ 327,474**	$ 344,785
Business acquisitions	**-**	-	**36,756**	170,782	**36,756**	170,782
Property acquisitions	**-**	-	**138,493**	27,943	**138,493**	27,943
Property dispositions	**-**	-	**(46,476)**	(60,569)	**(46,476)**	(60,569)
Total expenditures	**$ 56,162**	$ 44,111	**$ 400,085**	$ 438,830	**$ 456,247**	$ 482,941
Property, plant and equipment						
Cost	**$ 1,493,039**	$ 1,164,310	**$ 4,710,725**	$ 4,247,819	**$ 6,203,764**	$ 5,412,129
Less: Accumulated depletion, depreciation, amortization and accretion	**(162,810)**	(72,277)	**(1,572,449)**	(1,142,345)	**(1,735,259)**	(1,214,622)
Net book value	**$ 1,330,229**	$ 1,092,033	**$ 3,138,276**	$ 3,105,474	**$ 4,468,505**	$ 4,197,507
Goodwill						
Beginning of year	**$ 175,984**	$ 209,930	**$ 676,794**	$ 656,248	**$ 852,778**	$ 866,178
Addition (reduction) to goodwill	**40,246**	(33,946)	**817**	20,546	**41,063**	(13,400)
End of year	**$ 216,230**	$ 175,984	**$ 677,611**	$ 676,794	**$ 893,841**	$ 852,778

(1) Accounting policies for segments are the same as those described in the Significant Accounting Policies.
(2) Of the total downstream revenue for the year ended December 31, 2008, two customers represent sales of $2,818.1 million and $592.0 million respectively (2007 - $2,651.5 million and nil). No other single customer within either division represents greater than 10% of Harvest's total revenue.
(3) Downstream operating expenses for the period ended December 31, 2008 include $5.6 million of turnaround and catalyst costs (2007 - $34.5 million).
(4) Total Assets on a consolidated basis includes $36.1 million (2007 - $16.4 million) relating to the fair value of risk management contracts.
(5) There is no intersegment activity.

22. Commitments, Contingencies and Guarantees

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, 2008:

(a) North Atlantic has a Supply and Offtake Agreement with Vitol Refining S.A. This agreement, which continues on a monthly basis with a mutual six months termination notice period, provides that the ownership of substantially all crude oil feedstock and refined product inventory at the refinery be retained by Vitol Refining S.A. and that Vitol Refining S.A. will be granted 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, at December 31, 2008, North Atlantic had commitments totaling approximately $319.7 million (2007 - $843.6 million) in respect of future crude oil feedstock purchases and related transportation from Vitol Refining S.A.

(b) North Atlantic has an agreement with Newsul Enterprises Inc. ("Newsul") whereby North Atlantic committed to provide Newsul with its inventory and production of sulphur to February 12, 2018.

Newsul has named North Atlantic in a claim in the amount of US$2.7 million and has requested the services of an arbitration board to make a determination on the claim. The claim is for additional costs and lost revenues related to alleged contaminated sulphur delivered by North Atlantic. An accrual of $0.5 million has been established based on North Atlantic's estimate of their liability, but since the eventual outcome of the arbitration hearing is undeterminable, there exists an exposure to loss in excess of the amount accrued.

(c) North Atlantic has an environmental agreement with the Province of Newfoundland and Labrador, Canada, committing to programs that reduce the environmental impact of the refinery over time. Initiatives include a schedule of activities to be undertaken with regard to improvements in areas such as emissions, waste water treatment, terrestrial effects, and other matters. In accordance with the agreement, certain projects have been completed and others have been scheduled. Costs relating to certain activities scheduled to be undertaken over the next two years are estimated to be approximately $3.3 million and are included in the table below; costs can not yet be estimated for the remaining projects.

(d) North Atlantic has been named a defendant in The State of New Hampshire versus Amerada Hess Corp. et al, one of more than 100 methyl tertiary butyl ether ("MTBE") U.S. product liability litigation cases that have been consolidated for pre-trial purposes in this matter. The plaintiffs seek relief for alleged contamination of ground water from the various defendants' use of the gasoline additive MTBE. Although the plaintiffs have not made a particular monetary demand, they are asserting collective and joint liability against all defendants. All consolidated lawsuits are at a preliminary stage and, accordingly, it is too early in the legal process to reach any conclusion regarding the ability of the State of New Hampshire to properly assert jurisdiction over North Atlantic in the lawsuit or to reach any conclusions regarding the substance of the plaintiffs' claims. Accordingly, the evaluation of the risk of liability to North Atlantic is not determinable at this time and no amounts are accrued in the consolidated financial statements in respect of this matter. Harvest is indemnified by Vitol Group B.V. in respect of this contingent liability.

(e) Petro-Canada, a former owner of the North Atlantic refinery, holds certain contractual rights in relation to production at the refinery, namely:

   i. a right to share, subject to a maximum limit, in the profits of the sale of any refined product, refined at the refinery, sold in Canada, exclusive of the province of Newfoundland and Labrador;

   ii. a right of first refusal to any refinery and/or terminaling capacity in excess of North Atlantic's requirements;

   iii. a right to participate in any venture to produce petrochemicals at the refinery; and

   iv. the rights in paragraphs (i) and (ii) above continue for a period of 25 years from December 1, 1986, while the rights in paragraph (iii) continue until amended by the parties.

(f) *Canada Revenue Agency Assessment*

In January 2009, Canada Revenue Agency issued a Notice of Reassessment to Harvest Energy Trust in respect of its 2002 through 2004 taxation years claiming past taxes, interest and penalties totaling $6.2 million. The CRA has adjusted Harvest Energy Trust's taxable income to include their net profits interest royalty income on an accrual basis whereas the tax returns had reported this revenue on a cash basis. A Notice of Objection has been filed with CRA requesting the adjustments to an accrual basis be reversed. The Harvest Energy Trust 2005 tax return has also been prepared on a cash basis for royalty income with no taxes payable and, if reassessed by CRA on a similar basis, there would have been approximately $40 million of taxes owing. The Harvest Energy Trust 2006 tax return has been prepared on an accrual basis including incremental payments required to align the prior year's cash basis of reporting with no taxes payable. Management along with our legal advisors believe the CRA has not properly applied the provisions of the Income Tax Act (Canada) that entitle income from a royalty to be included in taxable income on a cash basis and that the dispute will be resolved with no taxes payable by Harvest Energy Trust.

The following is a summary of Harvest's contractual obligations and commitments as at December 31, 2008:

	Payments Due by Period						
	2009	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Total**
Debt repayments [(1)]	-	1,226,228	304,500	-	-	-	**1,530,728**
Debt interest payments[(2)]	117,881	98,447	81,586	60,838	44,549	27,299	**430,600**
Capital commitments[(3)]	36,537	-	-	-	-	-	**36,537**
Operating leases[(4)]	7,868	7,005	6,069	2,274	566	566	**24,348**
Pension contributions[(5)]	6,900	7,038	7,179	7,322	7,469	7,618	**43,526**
Transportation agreements[(6)]	2,744	2,266	936	544	189	-	**6,679**
Feedstock commitments[(7)]	319,746	-	-	-	-	-	**319,746**
Contractual obligations	**491,676**	**1,340,984**	**400,270**	**70,978**	**52,773**	**35,483**	**2,392,164**

(1) Assumes that the outstanding Convertible Debentures either convert at the holders' option for Units or are redeemed for Units at Harvest's option.
(2) Interest determined on bank loan balance and rate effective at year end and by using the year end U.S. dollar exchange rate for the Senior Notes. At the Trust's option the interest on Convertible Debentures can be settled in Trust Units.
(3) Relating to drilling contracts, AFE commitments, equipment rental contracts and environmental capital projects.
(4) Relating to building and automobile leases.
(5) Relating to expected contributions for employee benefit plans [see Note 19].
(6) Relating to oil and natural gas pipeline transportation agreements.
(7) Relating to crude oil feedstock purchases and related transportation costs [see Note 22(a) above].

23. Reconciliation of the Consolidated Financial Statements to United States Generally Accepted Accounting Principles

These consolidated financial statements have been prepared in accordance with Canadian GAAP which, in most respects, conforms to U.S. GAAP. Any differences in accounting principles as they have been applied to the accompanying consolidated financial statements are not material except as described below. Items required for financial disclosure under U.S. GAAP may be different from disclosure standards under Canadian GAAP; any such differences are not reflected here.

The application of U.S. GAAP would have the following effects on net income as reported:

	Year Ended December 31	
	2008	2007
Net income (loss) under Canadian GAAP	**$ 212,019**	$ (25,676)
Adjustments		
Write-down of property, plant and equipment [(a)]	**(1,725,000)**	-
Depletion, depreciation, amortization and accretion [(b)]	**38,614**	78,180
Non-cash interest expense on debentures [(d)]	**10,688**	6,371
Non-cash interest expense on Senior Notes [(f)]	**1,397**	842
Amortization of deferred financing charges [(d)]	**(4,715)**	(3,471)
Currency exchange gain on Senior Notes [(f)]	**589**	1,720
Currency exchange gain on unit distribution [(g)]	**11,543**	10,045
Non-cash general and administrative expenses [(c)]	**(844)**	(443)
Future income tax recovery [(a)]	**112,372**	91,626
Net income (loss) under U.S. GAAP	**(1,343,337)**	159,194
Other comprehensive income		
Net change in cumulative translation adjustment [(g)]	**273,149**	(253,677)
Employee future benefits – actuarial gain (loss) [(h)]	**4,395**	(4,339)
Comprehensive income (loss)	$ **(1,065,793)**	$ (98,822)
Basic		
Net income (loss) per Trust Unit under U.S. GAAP	$ **(8.79)**	$ 1.15
Diluted		
Net income (loss) per Trust Unit under U.S. GAAP	$ **(8.79)**	$ 1.14
Statement of Accumulated Income		
Balance, beginning of year – U.S. GAAP	**564,390**	33,880
Net income (loss) – U.S. GAAP	**(1,343,337)**	159,194
Change in redemption value of Trust Units	**1,595,899**	371,316
Balance, end of year – U.S. GAAP	**816,952**	564,390
Accumulated other comprehensive income (loss)		
Balance, beginning of year – U.S. GAAP	**(210,430)**	47,586
Other comprehensive income	**277,544**	(258,016)
Balance, end of year – U.S. GAAP	**67,114**	(210,430)

The application of U.S. GAAP would have the following effect on the consolidated balance sheets as reported:

	December 31, 2008		December 31, 2007	
	Canadian GAAP	**U.S. GAAP**	Canadian GAAP	U.S. GAAP
Assets				
Property, plant and equipment [(a) (b)]	**$ 4,468,505**	**$ 2,255,407**	$ 4,197,506	$ 3,670,688
Deferred charges [(d) (f)]	**$ -**	**$ 28,740**	$ -	$ 23,390
Non current benefit plan assets [(h)]	**$ -**	**$ 466**	$ -	$ 393
Future income tax [(a)]	**$ -**	**$ -**	$ -	$ 4,986
Liabilities				
Accounts payable and accrued liabilities [(c)]	**$ 210,097**	**$ 209,474**	$ 270,240	$ 268,669
Current portion of convertible debentures [(d)]	**$ 2,513**	**$ 2,532**	$ 24,273	$ 24,210
Current other benefit plan liability [(h)]	**$ -**	**$ 223**	$ -	$ 170
7 $^{7/8}$%Senior notes [(f)]	**$ 298,210**	**$ 303,453**	$ 241,148	$ 246,710
Non current portion of convertible debentures [(d)]	**$ 825,246**	**$ 918,197**	$ 627,495	$ 671,818
Non current benefit plan liability [(h)]	**$ 10,551**	**$ 11,062**	$ 12,168	$ 17,054
Future income tax [(a)]	**$ 203,998**	**$ -**	$ 86,640	$ -
Temporary equity [(e)]	**$ -**	**$ 1,562,806**	$ -	$ 2,997,136
Unitholders' Equity				
Unitholders' capital [(e)]	**$ 3,897,653**	**$ -**	$ 3,736,080	$ -
Equity component of convertible debentures [(d)]	**$ 84,100**	**$ -**	$ 39,537	$ -
Contributed surplus	**$ 6,433**	**-**	-	-
Additional paid-in capital [(d)]	**$ -**	**$ 9,913**	$ -	$ 9,913
Accumulated income [(g)]	**$ 458,884**	**$ 816,952**	$ 246,865	$ 564,390
Accumulated other comprehensive income [(h)(g)]	**$ 87,933**	**$ 67,114**	$ (196,759)	$ (210,430)

(a) Under Canadian GAAP, Harvest performs an impairment test that limits the capitalized costs of its petroleum and natural gas assets to the discounted estimated future net revenue from proved and probable petroleum and natural gas reserves plus the cost of unproved properties less impairment, determined using estimated future prices and costs. The discount rate used is equal to Harvest's risk free interest rate.

Under U.S. GAAP, entities using the full cost method of accounting for petroleum and natural gas activities perform an impairment test on each cost centre using discounted future net revenue from proved petroleum and natural gas reserves discounted at 10%. The prices used under the U.S. GAAP impairment test are those in effect at year end. As at December 31, 2008, the application of the ceiling test under U.S. GAAP resulted in a write down of $1,725.0 million. There was no impairment under U.S. GAAP at December 31, 2007.

Under Canadian GAAP as at December 31, 2008, Harvest's carrying value of its net assets exceed its tax bases and accordingly results in recording a future income tax liability. Adjustments under U.S. GAAP result in a large future income tax recovery and elimination of the future income tax liability, as the ceiling test write down significantly lowered Harvest's property, plant, and equipment carrying value under U.S. GAAP and thus decreased the corresponding temporary differences for future tax purposes.

(b) Under Canadian GAAP, proved reserves are estimated using estimated future prices and costs. These proved reserves form the basis for the depletion calculation.

Under U.S. GAAP, proved reserves used for the depletion calculation are estimated using constant prices and costs as of the date the estimate of reserves is made. In both the current and prior year there were differences in the depletable base and in proved reserves under U.S. GAAP and Canadian GAAP and as a result the difference is realized in the depletion expense.

(c) Under Canadian GAAP, the Trust determines compensation expense and the resulting obligation related to its Trust Unit Incentive Plan and Unit Award Plan using the intrinsic value method described in Note 2(h). Under U.S. GAAP, Harvest follows SFAS 123(R) "*Share Based Payments*" using the modified prospective approach. Under FAS 123(R), expenses and obligations for liability-based stock compensation plans are recorded using the fair-value method of accounting and are revalued at each period end. As a result, general and administrative expense is higher under U.S. GAAP by $0.8 million for the year ended December 31, 2008 (2007 – $0.4 million) with a corresponding increase in accounts payable and accrued liabilities. As at December 31, 2008 the accounts payable and accrued liabilities is lower under U.S. GAAP by $0.6 million (December 31, 2007 – $1.6 million) due to the cumulative effect of this difference.

To the extent compensation costs relates to employees directly involved in natural gas and crude oil exploration and development activities, such amounts are capitalized to property, plant and equipment. Amounts not capitalized are recognized as administrative expenses.

(d) Under Canadian GAAP, Harvest's Convertible Debentures are classified as debt with a portion, representing the value associated with the conversion feature, being allocated to equity under Canadian GAAP. Issue costs related to the debentures are netted against each respective debt and equity component. In addition, under Canadian GAAP a non-cash interest expense representing the effective yield of the debt component and the amortization of the issue costs is recorded in the consolidated statements of income with a corresponding credit to the Convertible Debenture liability balance to accrete that balance to the full principal due on maturity.

Under U.S. GAAP, the Convertible Debentures are classified as debt in their entirety, and issue costs are recorded as deferred charges. To the extent that a portion of the issue costs are netted against the respective debt and equity components of the Convertible Debentures under Canadian GAAP there is a difference in the capitalization and amortization of the related deferred charges under U.S. GAAP. The non-cash interest expense recorded under Canadian GAAP is not be recorded under U.S. GAAP.

In addition, Convertible Debentures that are assumed in a business combination are recorded at their fair value at the date of the acquisition as part of the cost of the acquired enterprise. Under U.S. GAAP, if the conversion feature is in-the-money at the acquisition date (a beneficial conversion feature), the feature should be recognized and measured by allocating a portion of the proceeds equal to the intrinsic value of that feature to additional paid-in capital. Where the debenture has a stated redemption date, the corresponding value is recognized as a discount on the convertible debenture balance and accreted from the date of acquisition to the redemption date.

(e) Under Harvest's Trust Indenture, Trust Units are redeemable at any time on demand by the Unitholder for cash. Under U.S. GAAP, the amount included on the consolidated balance sheet for Unitholders' Equity would be reduced by an amount equal to the redemption value of the Trust Units as at the balance sheet date. The redemption value of the Trust Units is determined with respect to the trading value of the Trust Units as at each balance sheet date, and the amount of the redemption value is classified as temporary equity. Changes, if any, in the redemption value during a period results in a charge to accumulated income.

(f) With the adoption of Financial Instruments under Canadian GAAP effective January 1, 2007, issue costs are applied against the $7^{7/8}$% Senior Notes balance and accreted into income using the effective interest method. Under U.S. GAAP, these amounts are capitalized as a deferred charge and expensed into income using the effective interest method. There is also a currency exchange impact as the deferred charges and the debt balance of the Senior Notes, which is different under U.S. GAAP, are denominated in U.S. dollars.

(g) With the adoption of the new accounting standards for financial instruments under Canadian GAAP effective January 1, 2007, the cumulative translation adjustment generated upon translating the financial statements of Harvest's downstream operations denominated in a foreign currency previously recognized as a separate component of equity is now recognized in comprehensive income consistent with the treatment under U.S. GAAP. Additionally, under U.S. GAAP, partnership distributions are required to be translated at the historic foreign currency exchange rate in place at the time of initial paid-in capital and any translation gains or losses are recorded in other comprehensive income. Under Canadian GAAP, it is permissible to translate foreign currency denominated partnership distributions at the historic exchange rate that has been proportionately adjusted for the subsequent periods when income has been earned. The effects of the translation are reflected in net income.

(h) At December 31, 2006 the Trust adopted U.S. GAAP SFAS 158, "*Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R).* Under SFAS 158, the over-funded or under-funded status of our defined benefit postretirement plan are recognized on the balance sheet as an asset or liability and changes in the funded status are recognized through comprehensive income. As a result, for the year ended December 31, 2008 employee future benefits are lower by $4.4 million (2007 – higher by $4.3 million) and a $4.4 million gain was included in other comprehensive income (2007 – loss of $4.3 million included in accumulated other comprehensive income on adoption of SFAS 158). Canadian GAAP currently does not require the Trust to recognize the funding status of the plan on its balance sheet.

New Financial Accounting Pronouncements

(a) In December 2007, FASB issued Statement 141(R), *"Business Combinations"*, which replaces SFAS 141. The standard requires assets and liabilities acquired in a business combination, contingent consideration, and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination. SFAS No. 141(R) is applied prospectively to business combinations for which the acquisition date is on or after December 15, 2008. Harvest did not record any business combinations between the effective date and the year ended December 31, 2008. This standard will impact business combinations entered into after December 15, 2008.

(b) In March 2008, FASB issued Statement 161, "*Disclosures about Derivative Instruments and Hedging Activities*". This statement requires enhanced disclosures about derivative and hedging activity including how and why an entity uses derivative instruments and the derivative instruments effect on an entity's financial position, financial performance, and cash flows. This standard is effective for fiscal years beginning after November 15, 2008. The adoption of this standard will not have a material impact on the consolidated financial statements.

(c) In May 2008, FASB issued FASB Staff Position No. APB 14-1, *"Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)"*. An issuer of a convertible debt instrument within the scope of the staff position is required to separate the instrument into a liability-classified component and an equity-classified component. The staff position is effective for the fiscal year beginning after December 15, 2008. Harvest is currently assessing the impact of the staff position and expects that the guidance will bring U.S. GAAP in line with Canadian GAAP.

(d) In December 2008, the U.S. Securities and Exchange Commission promulgated that effective for fiscal 2009, the year-end proved reserve volumes are to be calculated using a twelve month average price as compared to the current standard which requires prices on the last day of the fiscal year.

24. Subsequent Events

Subsequent to December 31, 2008, Harvest declared a distribution of $0.05 per unit for Unitholders of record on March 23, 2009.

Between January 1, 2009 and February 28, 2009, an additional $292.3 million was committed to the purchase of feedstock inventory under the Supply and Offtake Agreement held with Vitol Refining S.A. [see table in Note 22].

25. Related Party Transactions

During the year ended December 31, 2008, Vitol purchased $320.9 million (2007 - $354.8 million) of crude oil pursuant to the terms and conditions of the Supply and Offtake Agreement from a company in which a director of Harvest holds a minority equity interest. On December 21, 2008, the director disposed the interest in the company and as such, subsequent to this date, this company no longer represents a related party.

26. Comparatives

Certain comparative figures have been reclassified to conform to the current year's presentation.

DISCLOSURE CONTROLS AND PROCEDURES

A. Certifications

See Exhibits 99.1 and 99.2 to this annual report on Form 40-F.

B. Evaluation of Disclosure Controls and Procedures

As of December 31, 2008, an evaluation was carried out under the supervision of and with the participation of Registrant’s management, including the President and Chief Executive Officer as well as the Chief Financial Officer, of the effectiveness of the Registrant’s disclosure controls and procedures (as defined in Rule 13a-15(e) and Rule 15d-15(e) under the Exchange Act). Based on that evaluation, the President and Chief Financial Officer concluded that as of the end of the fiscal year, the design and operation of these disclosure controls and procedures were effective to ensure that information required to be disclosed by the Registrant in reports it files or submits under the Exchange Act were (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission’s (“SEC”) rules and forms and (ii) accumulated and communicated to the Registrant’s management, including its President and Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

It should be noted that while the Registrant’s management, including its Chief Executive Officer and Chief Financial Officer believe that the Registrant’s disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Registrant’s disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

C. Management’s Annual Report on Internal Control Over Financial Reporting

The required disclosure is included in the “Management’s Report” that accompanies the registrant’s Consolidated Financial Statements for the fiscal year ended December 31, 2008, filed as part of this annual report on Form 40-F.

D. Attestation Report of the Registered Public Accounting Firm

The required disclosure is included in the “Auditor’s Report” that accompanies the registrant’s Consolidated Financial Statements for the fiscal year ended December 31, 2008, filed as part of this annual report on Form 40-F.

E. Changes in Internal Control over Financial Reporting

During the period covered by this annual report on Form 40-F, no change occurred in the Registrant’s internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Registrant’s internal control over financial reporting.

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NOTICES PURSUANT TO REGULATION BTR

None.

AUDIT COMMITTEE

Identification of Audit Committee

The Registrant has a separately designed standing Audit Committee in accordance with Section 3(a)(58)(A) of the Exchange Act. The following individuals comprise the entire membership of the Registrant's Audit Committee: Dale Blue, Hector J. McFadyen, and William D. Robertson. In the view of the Registrant's Board of Directors, all members of the Audit Committee are independent as determined under Rule 10A-3 of the Exchange Act.

Audit Committee Financial Expert

The Board of Directors of the registrant has determined that William D. Robertson has met the "audit committee financial expert" criteria (as that term is defined in paragraph 8(b) of General Instruction B to Form 40-F) and the applicable rules of the New York Stock Exchange.

The SEC has indicated that the designation of a person as an "audit committee financial expert" does not (i) mean that such person is an "expert" for any purpose, including without limitation for purposes of Section 11 of the Securities Act of 1933, (ii) impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the audit committee and the board of directors in the absence of such designation, or (iii) affect the duties, obligations or liability of any other member of the audit committee or the board of directors.

CODE OF ETHICS FOR CHIEF EXECUTIVE OFFICER AND SENIOR FINANCIAL OFFICERS

The Registrant has adopted a Code of Ethics (as that term is defined in paragraph 9 of General Instruction B to Form 40-F) 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, Chief Operating Officer, Upstream, and Chief Operating Officer, Downstream. It, and any amendments to the code, is available in print without charge to any person who requests it. Such requests may be made by contacting the Registrant's Investor Relations and Communications Advisor via email at: information@harvestenergy.ca or by phone at (403) 265-1178. There were no waivers or amendments to the Code of Ethics in 2008.

PRINCIPAL ACCOUNTING FEES AND SERVICES – INDEPENDENT AUDITORS

Fees payable to the Registrant's independent auditor, KPMG LLP, for the years ended December 31, 2008 and December 31, 2007 totaled $1,010,000 and $1,411,650, respectively, as detailed in the following table. All funds are in Canadian dollars.

	Year ended December 31, 2008	Year ended December 31, 2007
Audit Fees	$ 935,000	$ 1,042,650
Audit-Related Fees	$ 75,000	$ 369,000
All Other Fees	$ -	$ -
TOTAL	$ 1,010,000	$ 1,411,650

The nature of the services provided by KPMG LLP under each of the categories indicated in the table is described below.

Audit Fees

Audit fees were for professional services rendered by KPMG LLP for the audit of the Registrant's annual financial statements and review of the Registrant's quarterly financial statements, as well as services provided in connection with statutory and regulatory filings or engagements including those related to prospectus offerings and their audit of internal controls over financial reporting.

Audit-Related Fees

Audit-related fees were for assurance and related services reasonably related to the performance of the audit or review of the annual statements and are not reported under "Audit Fees" above. These services consisted of French translation fees which have decreased over the prior year due to prospectus offerings completed by Harvest late in 2006 and during the first half of 2007.

All Other Fees

In 2008 and 2007, no fees for services were incurred other than those described above under "Audit Fees" and "Audit-Related Fees".

PREAPPROVAL POLICIES AND PROCEDURES

It is within the mandate of the Registrant's Audit Committee to approve all audit and non-audit related fees. The Audit Committee will be informed as to the term of engagement and the compensation paid to the external auditor of the Registrant as well as review and pre-approve the non-audit services actually provided by the auditor pursuant to this pre-approval process at its first scheduled meeting following such pre-approval. The auditors also present the estimate for the annual audit-related services to the Audit Committee for approval prior to undertaking the annual audit of the financial statements.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has no material off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on the Registrant's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that are material to investors.

CONTRACTUAL OBLIGATIONS

Annual Contractual Obligations *(000s)*	**Total**	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt[2]	**$ 1,530,728**	$ -	$ 1,530,728	$ -	$ -
Interest on long-term debt[4]	**104,781**	52,612	52,169	-	-
Interest on Convertible Debentures[3]	**325,818**	65,269	127,864	105,386	27,299
Operating and premise leases	**24,348**	7,868	13,074	2,840	566
Purchase commitments[5]	**36,537**	36,537	-	-	-
Asset retirement obligations[6]	**1,203,785**	14,214	30,790	26,958	1,131,823
Transportation [7]	**6,679**	2,744	3,202	733	-
Pension contributions[8]	**43,526**	6,900	14,217	14,791	7,618
Feedstock commitments	**319,746**	319,746	-	-	-
Total	**$ 3,595,948**	$ 505,890	$ 1,772,044	$ 150,708	$ 1,167,306

(1) As at December 31, 2008, we had entered into financial contracts for downstream production of refined products with average deliveries of approximately 20,000 bbl/d for the first half of 2009.
(2) Assumes that the outstanding Convertible Debentures either convert at the holders' option or are redeemed for Units at our option.
(3) Assumes no conversions and redemption by Harvest for Trust Units at the end of the second redemption period. Only cash commitments are presented.
(4) Assumes constant foreign exchange rate.
(5) Relates to drilling commitments, AFE commitments and downstream purchase commitments.
(6) Represents the undiscounted obligation by period
(7) Relates to firm transportation commitment on the Nova pipeline.
(8) Relates to the expected contributions for employee benefit plans.

In addition to those items noted above, as at December 31, 2008, we had entered into physical and financial contracts for deliveries of downstream refined product into 2009. Please see Note 20 to the Consolidated Financial Statements for the fiscal year ended December 31, 2008, filed as part of this annual report on Form 40-F.

For a discussion of the Registrant's other commitments, please read Note 22 to the Registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2008, filed as part of this annual report on Form 40-F.

UNDERTAKING

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the SEC staff, and to furnish promptly, when requested to do so by the SEC staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

CONSENT TO SERVICE OF PROCESS

The Registrant has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

Any change to the name or address of the agent for service of process of the registrant shall be communicated promptly to the SEC by an amendment to the Form F-X referencing the file number.

SIGNATURE

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report on Form 40-F to be signed on its behalf by the undersigned, thereto duly authorized, in the City of Calgary, Province of Alberta, Canada.

Dated: March 27, 2009

HARVEST ENERGY TRUST

By: /s/ Robert W. Fotheringham
Name: Robert W. Fotheringham
Title: Chief Financial Officer of Harvest Operations Corp. on behalf of Harvest Energy Trust

EXHIBIT INDEX

The following exhibits are filed as part of this report.

Exhibit Number	Description
99.1	CEO Certification pursuant to Rule 13a-14(a) or 15d-14 of the Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
99.2	CFO Certification pursuant to Rule 13a-14(a) or 15d-14 of the Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
99.3	CEO Certification pursuant to U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.4	CFO Certification pursuant to U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.5	Consent of KPMG LLP.
99.6	Consent of McDaniel & Associates Consultants Ltd.
99.7	Consent of GLJ Petroleum Consultants Ltd.

Exhibit 99.1

CERTIFICATION
REQUIRED BY RULE 13a-14(a) OR RULE 15d-14(a) OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John Zahary, certify that:

1. I have reviewed this annual report on Form 40-F of Harvest Energy Trust;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 27, 2009

/s/ John Zahary
Name: John Zahary
Title: President & Chief Executive Officer

EXHIBIT 99.2

CERTIFICATION
REQUIRED BY RULE 13a-14(a) OR RULE 15d-14(a) OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert W. Fotheringham, certify that:

1. I have reviewed this annual report on Form 40-F of Harvest Energy Trust;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 27, 2009

/s/ Robert W. Fotheringham____
Name: Robert W. Fotheringham
Title: Chief Financial Officer

EXHIBIT 99.3

CERTIFICATION
REQUIRED BY RULE 13a-14(b) OR RULE 15d-14(b) AND
SECTION 1350 OF CHAPTER 63 OF TITLE 18
OF THE UNITED STATES CODE

In connection with the annual report of Harvest Energy Trust (the "Trust") on Form 40-F for the year ended December 31, 2008 (the "Report") as filed with the Securities and Exchange Commission on the date hereof, I, John Zahary, President & Chief Executive Officer of the Trust, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Trust.

Dated: March 27, 2009

/s/ John Zahary
John Zahary
President & Chief Executive Officer

EXHIBIT 99.4

CERTIFICATION
REQUIRED BY RULE 13a-14(b) OR RULE 15d-14(b) AND
SECTION 1350 OF CHAPTER 63 OF TITLE 18 OF THE UNITED STATES CODE

In connection with the annual report of Harvest Energy Trust (the "Trust") on Form 40-F for the year ended December 31, 2008 (the "Report") as filed with the Securities and Exchange Commission on the date hereof, I, Robert W. Fotheringham, Chief Financial Officer of the Trust, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Trust.

Dated: March 27, 2009

/s/ Robert W. Fotheringham__
Robert W. Fotheringham
Chief Financial Officer

EXHIBIT 99.5

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of Harvest Operations Corp. on behalf of Harvest Energy Trust

We consent to the inclusion in this annual report on Form 40-F of:

- our audit report dated March 2, 2009 on the consolidated balance sheets of Harvest Energy Trust as at December 31, 2008 and 2007 and the consolidated statements of income (loss) and comprehensive income (loss), unitholders' equity and cash flows for each of the years in the two-year period ended December 31, 2008,

- our Report of Independent Registered Public Accounting Firm dated March 2, 2009 on the effectiveness of internal control over financial reporting as of December 31, 2008,

each of which is contained in this annual report on Form 40-F of the Trust for the fiscal year ended December 31, 2008.

signed "KPMG LLP"

Chartered Accountants

Calgary, Canada
March 27, 2009

EXHIBIT 99.6

CONSENT OF INDEPENDENT ENGINEERS

We hereby consent to the use in this Annual Report on Form 40-F of Harvest Energy Trust for the year ended December 31, 2008 of our report, dated March 13, 2009, evaluating the crude oil, natural gas, and natural gas liquids reserves attributable to properties owned by Harvest Energy Trust.

McDaniel & Associates Consultants Ltd.

Calgary, Alberta

Date: March 13, 2009

Sincerely,

/s/ C.B. Kowalski

C.B. Kowalski, P.Eng.
Vice President

EXHIBIT 99.7

CONSENT OF INDEPENDENT ENGINEERS

We hereby consent to the use in this Annual Report on Form 40-F of Harvest Energy Trust for the year ended December 31, 2008, our report, dated March 9, 2009, evaluating the crude oil, natural gas, and natural gas liquids reserves attributable to certain properties owned by Harvest Energy Trust.

GLJ Petroleum Consultants Ltd.

Calgary, Alberta

Date: March 17, 2009

Sincerely,

/s/ Myron J. Hladyshevsky______
Myron J. Hladyshevsky, P. Eng.
Vice-President