Full Year & Fourth Quarter Report 2009

for the full year and three month period ending December 31, 2009

SELECTED INFORMATION

The table below provides a summary of Harvest's financial and operating results for the twelve month periods ended - December 31, 2009 and 2008.

	Three Months Ended		Twelve Months Ended		
FINANCIAL *($000s except where noted)*	**Dec. 31, 2009**	Dec 31, 2008	**Dec. 31, 2009**	Dec 31, 2008	2008 to 2009 % Change
Revenue, net[1]	**$ 853,139**	$ 892,739	**$ 3,139,085**	$ 5,489,364	(43%)
Cashflow From Operating Activities	**76,999**	183,740	**473,602**	655,887	(28%)
Per trust unit, basic	**$ 0.41**	$ 1.18	**$ 2.73**	$ 4.29	(36%)
Per trust unit, diluted	**$ 0.41**	$ 1.10	**$ 2.72**	$ 4.05	(33%)
Net income (loss)[2]	**(13,022)**	78,640	**(935,634)**	212,019	(541%)
Per trust unit, basic	**$ (0.07)**	$ 0.50	**$ (5.38)**	$ 1.39	(517%)
Per trust unit, diluted	**$ (0.07)**	$ 0.50	**$ (5.38)**	$ 1.39	(517%)
Distributions declared	**9,113**	140,646	**164,770**	551,325	(70%)
Distributions declared, per trust unit	**0.05**	0.90	**$ 1.00**	$ 3.60	(72%)
Distributions declared as a percentage of Cashflow From Operating Activities	**12%**	77%	**35%**	84%	(58%)
Bank debt			**428,017**	1,226,228	(65%)
$7^{7/8}$% Senior Notes			**259,119**	298,210	(13%)
Convertible debentures			**837,870**	827,759	1%
Total financial debt[3]			**1,525,006**	2,352,197	(35%)
Total assets			**4,404,912**	5,745,407	(23%)
UPSTREAM OPERATIONS					
Light to medium oil (bbl/d)	23,281	25,088	**23,651**	25,093	(6%)
Heavy oil (bbl/d)	9,491	11,306	**10,261**	12,162	(16%)
Natural gas liquids (bbl/d)	2,714	2,770	**2,718**	2,624	4%
Natural gas (mcf/d)	83,610	96,079	**90,097**	96,315	(6%)
Total daily sales volumes (boe/d)	49,421	55,177	**51,646**	55,932	(8%)
Cash capital expenditures	31,720	82,975	**186,276**	271,312	(31%)
Operating Netback	**$** 32.81	$ 23.08	**$ 25.71**	$ 47.89	(46%)
DOWNSTREAM OPERATIONS					
Average daily throughput (bbl/d)	75,814	102,500	83,939	103,497	(19**%)**
Average Refining Margin (US$/bbl)	**$** 6.55	$ 3.93	**$** 9.12	$ 7.16	27%
Cash capital expenditures	9,097	24,317	43,875	56,162	(22**%)**

(1) Revenues are net of royalties

(2) Net Income (Loss) includes a future income tax recovery of $28.0 million (2008 - $108.6million) and an unrealized net loss from risk management activities of $37.9 million (2008 - net gains of $185.9 million) for the year ended December 31, 2009. Please see Notes 18 and 20 to the Consolidated Financial Statements for further information.

(3) Includes current portion of Convertible Debentures.

President's Message

During 2009, we saw a dramatic repositioning of Harvest with the year end acquisition of Harvest trust units by Korea National Oil Corporation (KNOC). Concurrent with the acquisition of the outstanding trust units, Harvest issued an incremental $600 million of shares to KNOC that allowed bank debt to be reduced by the same amount. In early 2010, we also issued an incremental $466 million of equity to KNOC; further reducing bank debt in advance of the required change-of-control offers to holders of the senior notes and convertible debentures. With the improved balance sheet and the elimination of the distribution, as well as an attractive asset base with identified growth opportunities, Harvest is well-positioned as a growth-oriented integrated oil company in Canada.

We have continued to focus on assets that have strong cashflow characteristics, and the opportunity for enhancement through cost-effective and sophisticated operational practices. Today we are fortunate to have a unique asset base that offers significant future upside cashflow potential in both our upstream and downstream businesses.

Ultimately, our employees and unique assets will be the key to our success as the markets change and provide new challenges and opportunities. Throughout 2009 and into 2010, we remain focused on value creation within our asset base and the pursuit of our sustainable growth strategy.

Currently, the economic environment for Harvest is varied with relatively strong crude oil and NGL prices offset by weaker natural gas prices and refining margins. We anticipate that we will continue to experience a volatile commodity price environment through 2010. In light of attractive investment opportunities in the asset base and with an improved balance sheet, we have increased our capital expenditure expectations for 2010 in both the upstream and downstream businesses.

Reserves

At December 31, 2009, Harvest's proved plus probable reserves were 199.5 mmboe, compared to 219.9 mmboe at December 31, 2008. Based on average 2009 production Harvest has maintained a reserve life of 10.6 years.

	As at December 31, 2009		As at December 31, 2008	
RESERVES (mmBOE)[(1)]	Gross	Net	Gross	Net
Proved reserves	**140.3**	**122.5**	154.3	132.6
Probable reserves	**59.2**	**50.3**	65.7	54.7
Total proved plus probable (P+P) reserves[(2)]	**199.5**	**172.9**	219.9	187.2

(1) A summary of Harvest's 2009 reserves is included in a separate press release issued March 8 2010.
(2) Columns may not add due to rounding.

Upstream Segment

The operational performance of Harvest's upstream business in 2009 was outstanding in a number of areas. Our production volume exceeded expectations with lower than expected operating costs. Our performance is highlighted by our gas exploration and development success in west central Alberta, ongoing technology-driven horizontal well development in southeastern Saskatchewan and the successful implementation of enhanced recovery in world class oil pools such as the Hay River oilfield in northeastern British Columbia.

With the addition of three new wells in 2009, production at our Chedderville area exceeded 2,500 boepd late in the third quarter and averaged over 2,100 boepd for the year. This Ostracod gas and NGL exploration prospect was identified in 2006 and the first exploratory well was drilled in 2007. The company has also recently identified Cardium oil opportunities on the same land with the first horizontal well spud in early 2010.

At Hay River, 2009 average production was just over 5,400 boepd compared to 4,600 boepd in 2008 reflecting the positive impact of our enhanced water injection and Q1 drilling program. Our capital program for 2009 resulted in the drilling of 45 wells, 23 of which were either water source or water injection wells which we expect will further enhance our oil recovery from this large medium gravity oil pool.

While those are only a few of the highlights of our upstream program, they demonstrate the type of opportunity inherent in our asset base and the technologically advanced capability of our organization to enhance the performance of our assets. Our focus remains on our upstream oil and gas assets and our sustainable growth strategy where we continuously strive to enhance recovery of our reserves in order to maximize the value of our assets.

For the upstream operations, our capital spending plan for 2010 has been set at $320 million with a focus on oil projects. We expect to have an active drilling program with approximately 190 wells to be drilled over the course of the year. We also plan to continue with EOR projects in our larger oil reservoirs at Hay River, Bellshill Lake, Wainwright and Suffield with planned spending of $26 million. We expect our EOR projects to reduce decline rates for an extended period with improved recoveries due to maintaining reservoir pressures and bolstering of traditional water flood projects with the introduction of chemical enhancements, such as alkaline surfactant polymers. Our continued focus on reservoir management and an increased level of drilling activity will likely result in increasing production volumes through the year. We also continue to be well positioned with coal bed methane, heavy oil and oil sands opportunities as technologies develop.

We anticipate that our upstream production will average approximately 36,000 bbls/d of liquids and 80,000 mcf/d of natural gas (approximately 50,000 boe/d). Light and medium gravity oil, including natural gas liquids, is expected to represent approximately 55% of our total production in 2010 with heavy oil and natural gas accounting for 18% and 27%, respectively. We continue to focus on operating costs and G&A costs and to pursue opportunities to reduce costs given the less active investment environment. For 2010, we are projecting our operating costs to be approximately $14.00 per boe and general and administrative costs to be approximately $1.80 per boe.

Downstream Segment

The downstream refining and marketing segment operates in Newfoundland and Labrador. This second component of our asset base provides vertical integration for our upstream crude oil business and a natural hedge for our crude oil quality discounts.

The downstream business is exposed to the margins between the price of the refined products we sell and the price of feedstocks we purchase and process. In 2009, refining margins in the first half of the year were very attractive due to large sour crude oil discounts and strong finished product margins, resulting in a significant increase in cashflow from operations relative to the first half of 2008.

Operationally, the refinery's performance throughout the year was strong. A major planned turnaround was successfully completed during the second quarter, expanding our hydrocracking capacity by an additional 1,000 barrels per stream-day. Operations in the third quarter resulted in throughputs similar to the first quarter; however, margins were considerably reduced. Fourth quarter margins were also weak, and Harvest took advantage of this to reduce throughputs and complete maintenance activities.

In November 2009, North Atlantic Refining Limited and Vitol Refining S.A. ("Vitol") entered into an amended Supply and Offtake Agreement ("SOA"). The amended terms of this 2-year evergreen SOA provide enhanced product sales pricing formulas, expanded working capital financing access, and reduced working capital financing costs.

During 2009, we made considerable progress toward the suite of Debottleneck Projects. This suite of projects is estimated to cost a total of approximately US$310 million through 2010 and 2011 and has compelling economics. It involves the licensing and incorporation of demonstrated and mature process technologies into existing processes to capture additional capacities, enhanced yields and reduced expenses. We spent approximately US$11 million advancing these projects during 2009.

In early 2010, a pump in the hydrocracking unit at our refinery failed resulting in a fire. This fire was successfully extinguished in a few hours in a safe manner. Unfortunately, the fire combined with weak margins resulted in the refinery having reduced throughput. A decision was made to shut down the entire refinery during the repairs so we could advance timing of routine maintenance and turnaround activities previously planned for later in the year. The refinery is expected to be fully operational by the end of March.

Our 2010 capital spending will be directed to maintenance activities and discretionary investments to improve reliability, increase throughput, enhance margins and reduce operating costs. We anticipate spending approximately $150 million on capital projects and an incremental $60 million on catalyst and turnaround costs. We expect an average throughput for 2010 of 90,000 bpd of feedstock with a refined product yield of 45% distillates, 30% gasoline and 25% HSFO. We expect that operating costs and purchased energy costs will aggregate to $6.09 per bbl.

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, 2009 and 2008. The information and opinions concerning our future outlook are based on information available at March 5, 2010.

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, 2009 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 – 2009

- The Arrangement Agreement with Korea National Oil Corporation ("KNOC") closed December 22, 2009 with the acquisition of all the issued and outstanding trust units by KNOC's Canadian subsidiary, KNOC Canada Ltd.
- Cash from operating activities of $473.6 million decreased from $655.9 million in the prior year as a $502.6 million decline in the contribution from upstream operations was was only partially offset by a $263.6 million reduction in the cash settlements on price risk management contracts, a $25.3 million increase in contribution from downstream operations and a $28.2 million reduction in cash interest expense.
- Upstream operations contributed $443.3 million of cash, down from $945.9 million in the prior year, reflecting the 38% year-over-year drop in realized commodity prices and an 8% reduction in production, partially offset by lower operating costs.
- Capital spending of $186.3 million in our upstream business, combined with net dispositions for the year, resulted in finding and development costs, including changes in future development costs, of $22.56 per boe of proved reserves and a reduction in Gross Proved plus Probable Reserves to 199.5 mmboe from 219.9 mmboe in the prior year.
- Downstream operations contributed $108.9 million of cash reflecting modestly improved refining margins partially offset by reduced annual throughput due to the turnaround of the hydrocracking and hydrogen units.
- Capital expenditures in our downstream operations totaled $43.9 million relating to various capital improvement projects including some debottlenecking initiatives.
- Lower commodity prices resulted in $62.8 million of favourable cash settlements on our price risk management contracts.
- Balance sheet liquidity was improved with the approximate $600 million repayment of bank indebtedness concurrent with the closing of the Arrangement Agreement with Korea National Oil Corporation on December 22, 2009 combined with the issuance of 17,330,000 Trust Units for net proceeds of $120.2 million in the Second Quarter.

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.

On October 21, 2009, Harvest entered into an Arrangement Agreement (the "Arrangement) with Korea National Oil Corporation ("KNOC") for the purchase of all of the issued and outstanding Trust Units of Harvest at a price of $10.00 per Trust Unit for an aggregate cash consideration of approximately $1.8 billion plus the assumption of approximately $2.3 billion of debt. The Arrangement closed December 22, 2009 with the acquisition of all the issued and outstanding trust units by KNOC's Canadian subsidiary, KNOC Canada Ltd. As a result of the acquisition, Harvest Trust Units were delisted from both the Toronto Stock Exchange and the New York Stock Exchange.

During 2009, cash from operating activities totaled $473.6 million, a $182.3 million decrease as compared to $655.9 million in the prior year. Cash generated from our upstream operations of $443.3 million in 2009 was approximately half the $945.9 million in the prior year, while the cash generated in our downstream operations of $108.9 million increased by 30% over the $83.6 million generated in the prior year. The $502.6 million decrease in our upstream operations reflects the year-over-year drop in commodity prices as well as lower production due to reduced capital spending and normal decline. The increased contribution from our downstream operations reflects the stronger gasoline and HSFO margins partially offset by reduced distillate margins, decreased discounts on feedstock costs and reduced annual throughput. We also realized a $263.6 million favourable change in the cash settlements of our price risk management contracts.

Our upstream operations averaged production of 51,646 boe/d in 2009 as compared to 55,932 boe/d in the prior year, reflecting an 8% reduction that was primarily due to reduced capital spending, net property dispositions and normal decline. Our operating costs of $258.7 million in 2009 were $42.2 million lower than the prior year mainly due to reduced power costs and reductions in repairs and maintenance and well servicing expenditures. Our operating netback of $25.71 per boe represents a 46% decrease over the prior year and is primarily attributed to lower commodity prices.

With our reduced level of capital spending and net dispositions for the year, our proved reserves at December 31, 2009 totaled 140.3 million boe down from 154.3 million boe at the end of 2008 and our proved plus probable reserves at December 31, 2009 totaled 199.5 million boe down from 219.9 million boe at the end of 2008. Including changes in future development costs, our 2009 finding and development costs averaged $22.56 per boe of proved reserves as compared to $25.97 per boe in the prior year and a three year average of $25.65 per boe. Including changes in future development costs, our 2009 finding, development and acquisition costs averaged $19.80 per boe of proved reserves as compared to $27.90 per boe in the prior year and a three year average of $24.89 per boe respectively. Proved reserve additions of 6 million boe are attributed to our 2009 capital program, enhanced oil recovery plans and new undeveloped reserves which, when coupled with the 1.1 million boe of net sold reserves during the year from our A&D program replaced 26% of 2009 production. Proved plus Probable reserve additions were net negative due to our disposition program, conversion of previously booked undeveloped probable reserves to proved, and some negative revisions. Relative to our 2009 netback price of $25.71/boe, our proved finding and development costs represent a recycle ratio of 1.1 while our finding, development and acquisition costs represent a recycle ratio of 1.3.

During 2009, our downstream operations generated $108.9 million of cash as compared to $83.6 million in the prior year with the increased contribution primarily the result of a $21.9 million increase in gross margin. Operationally, the refinery's performance throughout the year was solid, particularly during the period of greatest refining margin strength in the first quarter. The improved gross margin is a result of record setting margins in the First Quarter of 2009 from the operational hedging gain generated by the month-to-month hedging of the West Texas Intermediate ("WTI") price component of our crude oil feedstock purchase commitments through the Supply and Offtake Agreement we have with Vitol Refining S. A. A major planned turnaround was successfully completed during the second quarter, during which we expanded the capacity of our hydrocracking unit from 37,000 to 38,000 barrels per stream-day. The post-turnaround operations in the third quarter resulted in throughputs on par with the first quarter; however, margins were considerably reduced from those in the first quarter. The fourth quarter margins were also weak, and we successfully took advantage of particularly weak margin periods to reduce throughputs and complete some deferrable maintenance activities.

Refinery throughput averaged 83,939 bpd, representing a 73% utilization rate, primarily due to a shutdown in the Second Quarter to successfully complete a 42-day planned turnaround of the hydrocracking and hydrogen units, replacement of distillate hydrotreating and hydrocracking catalyst and regeneration of the naphtha reforming unit catalyst costing approximately $47.5 million. Fourth Quarter throughputs were also reduced to optimize refinery economics in response to changing market conditions and to conduct some planned maintenance on the crude and platformer units.

In 2009, lower commodity prices resulted in $62.8 million of favourable cash settlements on our price risk management contracts.

On June 4, 2009 we issued 17,330,000 Trust Units at an issue price of $7.30 per Trust Unit for net proceeds of $120.2 million after issue costs and used the net proceeds to reduce our bank borrowings.

Concurrent with closing the Arrangement, KNOC purchased an additional 60 million units at $10 per unit. Harvest repaid approximately $600 million of existing bank indebtedness and entered into an amended $600 million credit facility with a syndicate of lenders. In accordance with the indentures governing Harvest's $7^{7/8}$% Senior Notes and Convertible Debentures, KNOC made an offer to re-purchase these securities from their holders at a price of 101% of the principal amount plus accrued and unpaid interest. On January 29, 2010, KNOC agreed to make an additional capital contribution to Harvest of approximately $465.7 million, the proceeds of which was initially used to repay existing indebtedness.

In 2009, we declared distributions to Unitholders totaling $164.8 million ($1.00 per Trust Unit) representing 35% of our cash flow from operating activities as compared to $551.3 million ($3.60 per Trust Unit) representing 84% of our cash flow from operating activities in 2008. This decrease in distributions was due to a change in our monthly distribution from $0.30 per Trust Unit to $0.05 per Trust Unit commencing in March 2009, coupled with the suspension of distributions for the final two months of 2009 as a result of the Arrangement with KNOC.

Business Segments

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

	Year Ended December 31					
	2009			2008		
(in $000's)	**Upstream**	**Downstream**	**Total**	Upstream	Downstream	Total
Revenue[1]	**757,448**	**2,381,637**	**3,139,085**	1,294,769	4,194,595	5,489,364
Earnings From Operations[2]	**(679,810)**	**(173,300)**	**(853,110)**	498,786	14,125	512,911
Capital expenditures	**186,276**	**43,875**	**230,151**	271,312	56,162	327,474
Total assets[3]	**3,041,971**	**1,362,941**	**4,404,912**	3,933,632	1,775,688	5,745,407

(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, 2009 include nill (2008 - $36.1 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

2009 Highlights

- Operating cash flow of $443.3 million represents a decrease of $502.6 million over the prior year and reflects the year-over-year drop in commodity prices as well as lower production due to reduced capital spending and normal decline.
- Average production of 51,646 boe/d as compared to production of 55,932 boe/d in the prior year reflecting normal decline rates and the impact of reduced capital spending.
- Operating costs of $258.7 million ($13.72/boe) were $42.2 million lower than the $300.9 million ($14.70/boe) in the prior year, mainly due to reduced power costs and reductions in repairs and maintenance and well servicing expenditures.
- Operating netback of $25.71/boe represents a $22.18/boe (46%) decrease over the prior year and is attributed to substantially lower commodity prices.
- Capital spending of $186.3 million included the drilling of 107 wells (76.6 on a net basis) with a 99% success rate.

Summary of Financial and Operating Results

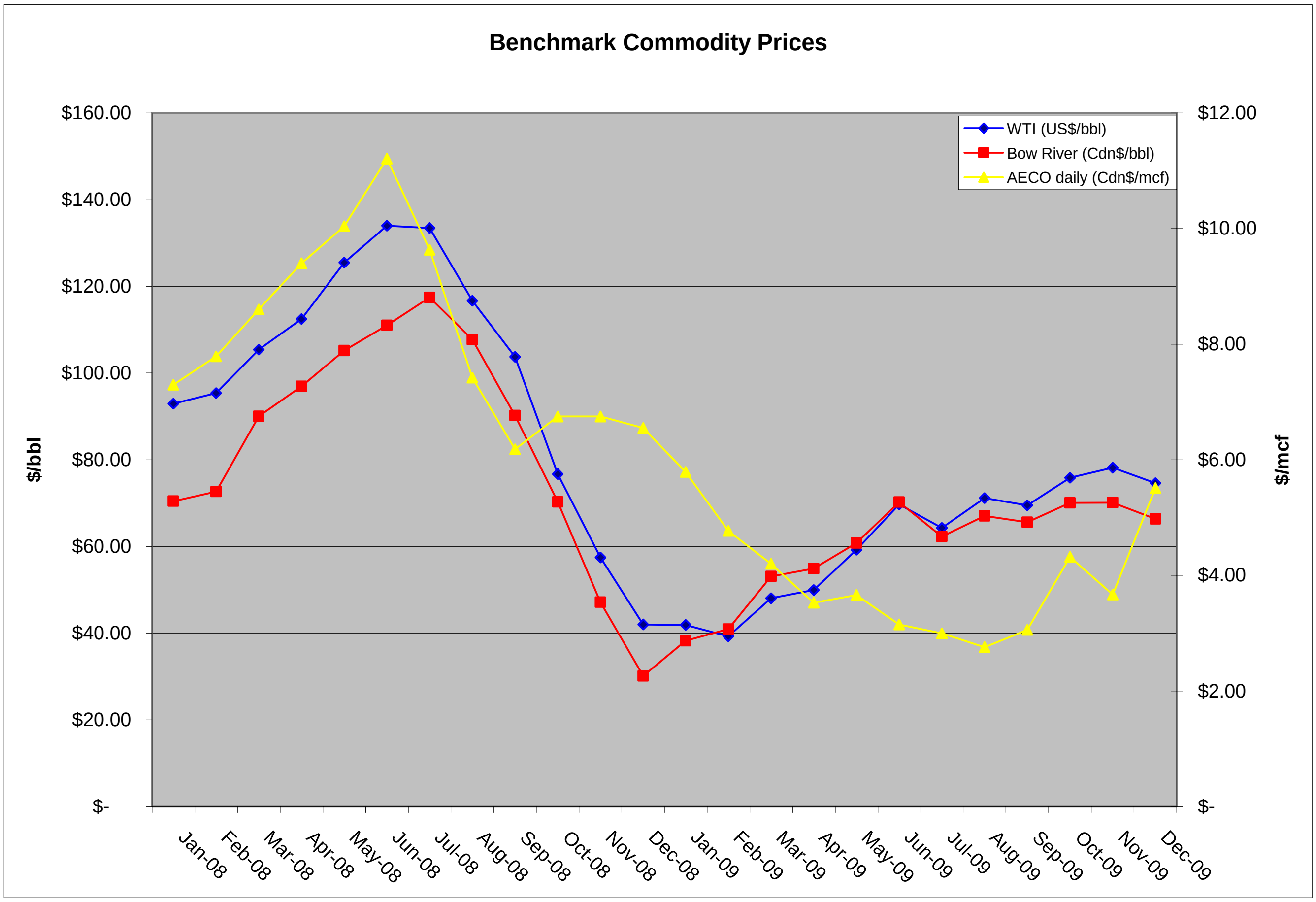
	Year Ended December 31		
(in $000's except where noted)	**2009**	2008	Change
Revenues	**886,308**	1,543,214	(43%)
Royalties	**(128,860)**	(248,445)	(48%)
Net revenues	**757,448**	1,294,769	(41%)
Operating expenses	**258,675**	300,890	(14%)
General and administrative	**36,452**	32,868	11%
Transportation and marketing	**14,228**	13,490	5%
Depreciation, depletion, amortization and accretion	**450,291**	448,735	0%
Goodwill Impairment	**677,612**	-	100%
Earnings (Loss) From Operations[1]	**(679,810)**	498,786	(236%)
Cash capital expenditures (excluding acquisitions)	**186,276**	271,312	(31%)
Property and business acquisitions, net of dispositions	**(62,116)**	128,773	(148%)
Daily sales volumes			
Light to medium oil (bbl/d)	**23,651**	25,093	(6%)
Heavy oil (bbl/d)	**10,261**	12,162	(16%)
Natural gas liquids (bbl/d)	**2,718**	2,624	4%
Natural gas (mcf/d)	**90,097**	96,315	(6%)
Total (boe/d)	**51,646**	55,932	(8%)

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

Commodity Price Environment

	Year Ended December 31		
Benchmarks	**2009**	2008	Change
West Texas Intermediate crude oil (US$ per barrel)	**61.80**	99.65	(38%)
Edmonton light crude oil ($ per barrel)	**65.93**	102.02	(35%)
Bow River blend crude oil ($ per barrel)	**59.97**	84.10	(29%)
AECO natural gas daily ($ per mcf)	**3.95**	8.14	(51%)
Canadian / U.S. dollar exchange rate	**0.880**	0.943	(7%)

The following graph summarizes benchmark commodity prices for our upstream production for the period of January 2008 to December 2009:



During 2009, the average WTI benchmark price was 38% lower than the prior year. The average Edmonton light crude oil price ("Edmonton Par") also decreased from the prior year to average $65.93 in 2009, a decrease of 35%. The decrease in Edmonton Par has been less than that of the WTI benchmark price due to the relative weakening, on an annual average basis, of the Canadian dollar relative to the US dollar.

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 2009, the Bow River heavy oil differential relative to Edmonton Par tightened to an average of $5.96/bbl (or 9.0%) compared to $17.92/bbl (or 17.6%) in 2008. 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.

	2009				2008			
Differential Benchmarks	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Bow River Blend differential to Edmonton Par ($/bbl)	**7.81**	**6.62**	**3.91**	**5.50**	14.07	16.48	21.50	19.63
Bow River Blend differential as a % of Edmonton Par	**10.2%**	**9.2%**	**5.9%**	**11.1%**	22.2%	13.5%	17.1%	20.2%

Compared to the prior year, the average AECO daily natural gas price was 51% lower during the year ended December 31, 2009. Natural gas prices have weakened as a result of increased storage levels and decreased economic activity which has led to a decline in industrial consumption.

Realized Commodity Prices [(1)]

The following table summarizes our average realized price by product for 2009 and 2008.

	Year Ended December 31		
	2009	2008	Change
Light to medium oil ($/bbl)	**58.18**	89.72	(35%)
Heavy oil ($/bbl)	**52.91**	77.22	(31%)
Natural gas liquids ($/bbl)	**45.03**	75.16	(40%)
Natural gas ($/mcf)	**4.29**	8.60	(50%)
Average realized price ($/boe)	**47.02**	75.39	(38%)

(1) Realized commodity prices exclude the impact of price risk management activities.

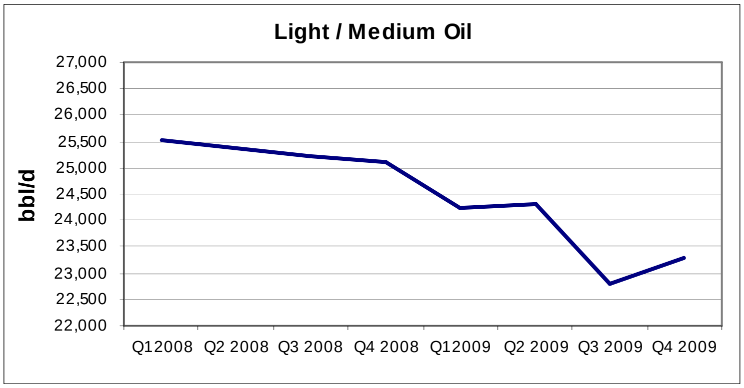
Our realized price for light to medium oil sales decreased by $31.54/bbl (or 35%) compared to the prior year, reflecting the $36.09/bbl (or 35%) decrease in Edmonton Par pricing. Harvest's heavy oil price decreased by $24.31/bbl (or 31%) compared to the prior year, reflecting the $24.13/bbl (or 29%) decrease in the Bow River price. Our average realized price for natural gas production decreased by $4.31/mcf (or 50%) compared to the prior year, reflecting the $4.19/mcf (or 51%) decrease in AECO daily pricing over the year.

Sales Volumes

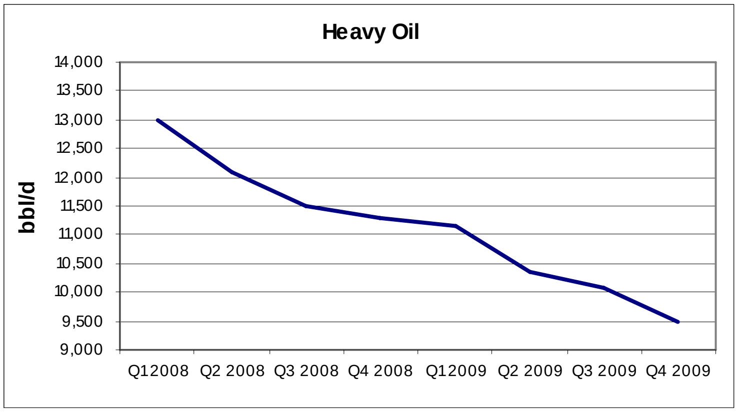
The average daily sales volumes by product were as follows:

	Year Ended December 31				
	2009		2008		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)[(1)]	**23,651**	**46%**	25,093	45%	(6%)
Heavy oil (bbl/d)	**10,261**	**20%**	12,162	22%	(16%)
Natural gas liquids (bbl/d)	**2,718**	**5%**	2,624	5%	4%
Total liquids (bbl/d)	**36,630**	**71%**	39,879	72%	(8%)
Natural gas (mcf/d)	**90,097**	**29%**	96,315	28%	(6%)
Total oil equivalent (boe/d)	**51,646**	**100%**	55,932	100%	(8%)

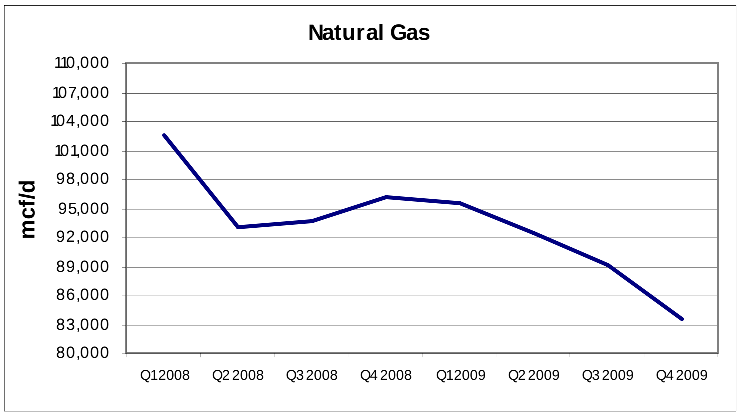
(1) Harvest classifies our oil production, except that produced from Hay River, as light to medium and heavy according to NI 51-101 guidance. The oil produced from Hay River has an average API of 24° (medium grade) and is classified as a light to medium oil, notwithstanding that, it benefits from a heavy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



Our light/ medium oil production was 23,651 bbl/d, a decrease of 1,442 bbl/d or 6%. The decrease is attributed to a combination of some additional downtime in the first quarter associated with cold weather, pipeline service disruptions at our Hay River property in the third quarter due to maintenance and normal decline associated with decreased capital spending throughout 2009.



Our heavy oil production has decreased steadily over the past twelve months resulting in a 16% reduction with year-to-date production of 10,261 bbl/d compared to 12,162 bbl/d in 2008. This reduction is largely the result of normal decline, increased water cuts on our large producing wells in the west central Saskatchewan and Lloydminster areas, and reduced spending on our heavy oil properties due to weak commodity prices.



Our 2009 natural gas production decreased by 6% relative to 2008, averaging 90,097 mcf/d. This reduction is due to normal decline resulting from reduced capital spending, downtime at certain third-party processing facilities in the Second Quarter 2009 coupled with the divestment of our Channel Lake properties, partially offset by production added from the acquisition of Pegasus in August 2009.

Revenues

	Year Ended December 31		
(000's)	**2009**	2008	Change
Light to medium oil sales	**$ 502,239**	$ 824,014	(39%)
Heavy oil sales	**198,168**	343,717	(42%)
Natural gas sales	**141,225**	303,303	(53%)
Natural gas liquids sales and other	**44,676**	72,180	(38%)
Total sales revenue	**886,308**	1,543,214	(43%)
Royalties	**(128,860)**	(248,445)	(48%)
Net Revenues	**$757,448**	$ 1,294,769	(41%)

Our revenue is impacted by changes in production volumes, commodity prices and currency exchange rates. Our 2009 total sales revenue of $886.3 million is $656.9 million lower than the prior year, of which $534.9 million is attributed to lower realized prices and $122.0 million is in respect of lower production volumes. The price decrease reflects the 35% decrease in Edmonton Par pricing and the 51% decrease in AECO daily natural gas pricing, while our decreased production volume is attributed to decline rates and a reduction in current year capital spending.

Light to medium oil sales revenue for 2009 was $321.8 million lower than the prior year due to a $272.3 million unfavourable price variance coupled with a $49.5 million unfavourable volume variance. Heavy oil sales revenue of $198.2 million in 2009 was $145.5 million lower than in the prior year due to a $91.0 million unfavourable price variance and a $54.5 million unfavourable volume variance. Natural gas sales revenue decreased by $162.1 million due to a $141.7 million unfavourable price variance and a $20.4 million unfavourable volume variance.

During 2009, natural gas liquids and other sales revenue decreased by $27.5 million compared to the prior year resulting from a $29.9 million unfavourable price variance offset by a $2.4 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.

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 2009, net royalties as a percentage of gross revenue were 14.5% (2008 – 16.1%) and aggregated to $128.9 million (2008 - $248.4 million). The decrease in our royalty rate throughout 2009 as compared to 2008 is due to reduced royalty rates in a lower commodity price environment as mandated by the Government of Alberta's new Royalty Framework.

Operating Expenses

	Year Ended December 31				
	2009		2008		Per BOE
(000's except per boe amounts)	**Total**	**Per BOE**	Total	Per BOE	Change
Operating expense					
Power and fuel	**$ 55,892**	**$ 2.97**	$ 80,162	$ 3.92	(24%)
Well Servicing	**48,152**	**2.55**	52,561	2.57	(1%)
Repairs and maintenance	**42,834**	**2.27**	51,462	2.51	(10%)
Lease rentals and property taxes	**30,857**	**1.64**	27,953	1.37	20%
Processing and other fees	**17,444**	**0.92**	15,073	0.74	24%
Labour – internal	**22,616**	**1.20**	23,785	1.16	3%
Labour – contract	**15,740**	**0.83**	17,128	0.84	(1%)
Chemicals	**13,946**	**0.74**	15,968	0.78	(5%)
Trucking	**10,488**	**0.56**	11,297	0.55	2%
Other	**706**	**0.04**	5,501	0.26	(85%)
Total operating expense	**$ 258,675**	**$ 13.72**	$ 300,890	$ 14.70	(7%)
Transportation and marketing expense	**$ 14,228**	**$ 0.75**	$ 13,490	$ 0.66	14%

Our 2009 operating costs totaled $258.7 million, a reduction of $42.2 million from 2008. On a per barrel basis, operating costs have decreased 7% to $13.72/boe as compared to $14.70/boe in the prior year, substantially attributed to reduced power and fuel costs, and to a lesser extent, reductions in repairs and maintenance expenses as a result of reduced activity in the industry in the current year.

Power and fuel costs, comprised primarily of electric power costs, represented approximately 22% of our total operating costs during 2009. The average Alberta electric power price of $47.85/MWh in the year was 47% lower than the average 2008 price of $89.95/MWh and this decrease is reflected in our 24% per boe decrease in power and fuel costs compared to the prior year, offset by the power consumption at Hay River that is provided by BC Hydro and was not subject to the same price reductions. We had electric power price risk management contracts in place from April 2009 through December 2009 which resulted in a loss of $1.3 million compared to a gain of $10.0 million on the contracts held in place throughout the prior year. 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)	**2009**	2008	Change
Electric power and fuel costs	**$ 2.97**	$ 3.92	(24%)
Realized losses (gains) on electricity risk management contracts	**0.07**	(0.49)	114%
Net electric power and fuel costs	**$ 3.04**	$ 3.43	(11%)
Alberta Power Pool electricity price (per MWh)	**$ 47.85**	$ 89.95	(47%)

Transportation and marketing expense for 2009 was $14.2 million or $0.75/boe, an increase of 14% per boe from $13.5 million or $0.66 per boe in 2008. The increased transportation and marketing expense in 2009 is primarily due to additional clean oil trucking costs at our Hay River property while the facilities were in turnaround and pipeline service was disrupted. These costs relate primarily to delivery of natural gas to Alberta's natural gas sales hub, the AECO Storage Hub, and our cost of trucking clean crude oil to pipeline receipt points. As a result, the total dollar amount of costs fluctuates in relation with our production volumes while the cost per boe typically remains relatively constant.

Operating Netback

	Year Ended December 31	
(per boe)	**2009**	2008
Revenues	**$ 47.02**	$ 75.39
Royalties	**(6.84)**	(12.14)
Operating expense	**(13.72)**	(14.70)
Transportation and marketing expense	**(0.75)**	(0.66)
Operating netback[1]	**$ 25.71**	$ 47.89

[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 2009, our operating netback decreased by $22.18/boe or 46% over the prior year. The decrease in our operating netback is primarily attributed to a $28.37/boe decrease in realized commodity prices, reflecting the decreases in Edmonton Par, Bow River and AECO pricing over the prior year, offset by a decrease in royalties of $5.30/boe and a 7% decrease in operating expenses.

General and Administrative ("G&A") Expense

	Year Ended December 31		
(000's except per boe)	**2009**	2008	Change
Cash G&A	**$ 35,795**	$ 33,643	7%
Unit based compensation expense (recovery)	**658**	(775)	185%
Total G&A	**$ 36,453**	$ 32,868	11%
Cash G&A per boe ($/boe)	**$ 1.90**	$ 1.64	16%

For the year ended December 31, 2009, Cash G&A costs increased by $2.2 million (or 7%) 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, over 80% of our Cash G&A expenses are related to salaries and other employee related costs.

Our unit based compensation plans provided 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 Plan of Arrangement with KNOC resulted in the accelerated vesting and cash payout of all outstanding Trust Unit Incentive Rights and Unit Awards on December 31, 2009 and accordingly, the unit based compensation expense recognized. The market price of our Trust Units was $10.50 at December 31, 2008 compared to $10.00 on December 22, 2009 when the Trust Unit Incentive Rights and Unit Awards were settled. Total unit based compensation expense increased $1.4 million in 2009 compared to 2008 as the result of the settlement of the unit based compensation plan with the closing of the acquisition of Harvest by the Korea National Oil Corporation ("KNOC") in December.

Depletion, Depreciation, Amortization and Accretion Expense

	Year Ended December 31		
(000's except per boe)	**2009**	2008	Change
Depletion, depreciation and amortization	**$ 407,239**	$ 414,969	(2%)
Depletion of capitalized asset retirement costs	**18,315**	15,135	21%
Accretion on asset retirement obligation	**24,737**	18,631	33%
Total depletion, depreciation, amortization and accretion	**$ 450,291**	$ 448,735	0%
Per boe	**$ 23.89**	$ 21.92	9%

Our overall depletion, depreciation, amortization and accretion ("DDA&A") expense for the year ended December 31, 2009 was relatively unchanged from the prior year. The nominal increase is attributed to slightly higher finding, development and acquisition costs that have increased our depletion rate, partially offset by lower production volumes.

Capital Expenditures

	Year Ended December 31	
(000's)	**2009**	2008
Land and undeveloped lease rentals	**$ 3,459**	$ 7,762
Geological and geophysical	**1,509**	6,782
Drilling and completion	**88,811**	164,628
Well equipment, pipelines and facilities	**81,626**	81,680
Capitalized G&A expenses	**10,756**	10,235
Furniture, leaseholds and office equipment	**114**	225
Development capital expenditures excluding acquisitions and non-cash items	**186,276**	271,312
Non-cash capital additions (recoveries)	**1,604**	(251)
Total development capital expenditures excluding acquisitions	**$ 187,880**	$ 271,061

In 2009, approximately 48% of our development capital expenditures were incurred to drill 107 gross wells with a success rate of 99%, compared to 247 gross wells with a success rate of 100% in 2008. Drilling activity was down in 2009 relative to 2008 due to the low oil price environment encountered at the start of the year, and although prices did strengthen during the year, Harvest maintained a reduced capital budget throughout 2009.

Our 2009 drilling activity focused primarily on our Hay River property where we drilled 45 gross wells. Of the 45 wells drilled, 23 were part of Harvest's Enhanced Oil recovery project at Hay either providing additional water source for increased injection, or new water injection wells. Hay River produces medium gravity crude oil from the Bluesky formation and has been a focus for Harvest's Enhanced Oil Recovery activity as we continue to see the benefits of the increased water injection and improved oil recovery.

In addition to Hay River, Harvest's oil focused drilling program included 9 gross wells at SE Saskatchewan utilizing horizontal wells to access light crude oil in the Souris Valley and Bakken formations as well as 8 gross wells in Red Earth where we have pursued light oil in the Slave Point and Granite Wash formations, and more recently the application of staged fracturing technology to horizontal wells targeting the Slave Point. At Chedderville, in our Rimbey area, an additional 3 gross wells were drilled targeting the natural gas and natural gas liquids in the Ostracod formation, which contributed to production from this field increasing to over 2,500 boepd late in the third quarter and averaging over 2,100 boepd for the year.

Our enhanced oil recovery ("EOR") efforts continue. In addition to our project at Hay River, enhanced water injection has been continuing into our Bellshill Lake medium gravity crude oil pool, and our Suffield (Lark) heavy oil pool, and we continue to monitor these projects for increased production response. At Wainwright, we initiated polymer injection into the medium gravity Sparky oil pool in June 2009, and we have observed pressure response to the flood late in the year which is a positive indication that the polymer is beginning to improve the oil sweep on this existing waterflood.

The $81.6 million of well equipment, pipelines and facilities expenditures during 2009 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.

The following summarizes Harvest's participation in gross and net wells drilled during 2009:

	Total Wells		Successful Wells		Abandoned Wells	
Area	**Gross[(1)]**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Hay River	45.0	45.0	45.0	45.0	-	-
Southeast Alberta	25.0	11.5	25.0	11.5	-	-
Rimbey	11.0	3.6	11.0	3.6	-	-
SE Saskatchewan	9.0	6.0	9.0	6.0	-	-
Red Earth	8.0	5.7	7.0	5.4	1.0	0.3
Lloyd/Hayter	3.0	1.5	3.0	1.5	-	-
Suffield	1.0	1.0	1.0	1.0	-	-
Other Areas	5.0	2.3	5.0	2.3	-	-
Total	107.0	76.6	106.0	76.3	1.0	0.3

(1) Excludes 3 additional wells that we have an overriding royalty interest in.

Our 2009 capital development program of $186.3 million was complemented by our acquisition of Pegasus Oil & Gas which was completed in August 2009 at a cost of approximately $19 million and was the only significant acquisition made during the year. Harvest used 2009 to capture value on some of the minor assets within our portfolio, and completed approximately $ 64.8 million of dispositions. With a reduced level of investment relative to 2008 and increased focus on dispositions, Harvest Gross Proved Reserves at December 31, 2009 dropped to 140.3 mmboe as compared to 154.3 mmboe at December 31, 2008, and Gross Proved plus Probable Reserves were 199.5 mmboe as compared to 219.9 mmboe.

Acquisitions and Divestitures

During the Second Quarter, we closed the sale of two non-operated properties for net proceeds of approximately $63 million. The sale of our natural gas interests in Channel Lake for approximately $43 million resulted in a disposition metric of approximately $53,000 per boe based on its current production of 4,860 mcf/d and approximately $2.30 per mcf based on proved plus probable reserves of approximately 19 bcf. Our sale of certain non-operated interests in the Pembina area for approximately $20 million resulted in a disposition metric of approximately $94,800 per boe based on its current production of 211 boe/d (weighted 70% light oil and natural gas liquids and 30% natural gas) and approximately $13.00 per boe based on proved plus probable reserves of 1,520 mboe. The net proceeds were applied to reduce our bank borrowings.

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

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. At September 30, 2009, it was determined that an impairment test was required for the Upstream reporting unit due to the reasonable expectation that a significant portion of, or all, of the reporting unit would be sold. The Arrangement Agreement with KNOC was considered to be an indication of fair value of the issued and outstanding trust units of Harvest from which a fair value of the Upstream reporting unit could be reasonably determined. Based on this, it was determined that the fair value of the Upstream reporting unit was below its carrying value at September 30, 2009 indicating a potential impairment. Subsequently, the fair value of the Upstream goodwill was determined by valuing the reporting unit’s net assets in the same manner as allocating a purchase price in a business combination. It was determined that the goodwill associated with the upstream reporting unit was fully impaired and a charge of $677.6 million was recorded in the financial results for the year ended December 31, 2009.

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 $17.9 million during 2009 as a result of accretion expense of $24.7 million, new liabilities recorded of $0.3 million, and upward revisions in estimates of $7.2 million, offset by $14.3 million of actual asset retirement expenditures incurred.

DOWNSTREAM OPERATIONS

2009 Highlights

- Cash from Downstream operations totaled $108.9 million (2008 - $83.6 million) reflecting improved margins, gains from operationally hedging our feedstock costs, and a weakening of the Canadian dollar relative to the US dollar, offset by reduced annual throughput.
- An average refining margin of US$9.12/bbl reflects a US$1.96 increase over the prior year primarily attributed to higher margins on gasoline and HSFO relative to the WTI benchmark price and gains from operationally hedging our feedstock costs.
- Refinery throughput averaged 83,939 bpd, representing a 73% utilization rate, primarily due to a shutdown in the Second Quarter to successfully complete a 42-day planned turnaround of the hydrocracking and hydrogen units, replacement of distillate hydrotreating and hydrocracking catalyst and regeneration of the naptha reforming unit catalyst costing approximately $47.5 million. Fourth Quarter throughputs were also reduced to optimize refinery economics in response to changing market conditions and to conduct some planned maintenance on the crude and platformer units.
- Refining operating costs of $2.71/bbl of throughput as compared to $2.08/bbl in the prior year reflect decreased throughput and additional repairs and maintenance costs resulting in total refining operating costs of $82.9 million ($78.9 million in 2008).

- Cost of purchased energy decreased to $3.00/bbl of throughput as compared to $3.48/bbl in the prior year reflecting a lower commodity price environment as compared to the prior year.
- Capital spending totaled $43.9 million as compared to $56.2 million in the prior year with $11.2 million incurred for the debottleneck projects.

Summary of Financial and Operational Results

	Year Ended December 31		
(in $000's except where noted below)	**2009**	2008	Change
Revenues	**2,381,637**	4,194,595	(43%)
Purchased feedstock for processing and products purchased for resale[4]	**2,015,671**	3,850,507	(47%)
Gross margin[1]	**365,966**	344,088	6%
Costs and expenses			
Operating expense	**102,556**	98,736	4%
Purchased energy expense	**91,868**	131,878	(30%)
Turnaround and catalyst expense	**47,487**	5,645	741%
Marketing expense and other	**12,009**	20,753	(42%)
General and administrative expense	**1,593**	1,875	(15%)
Depreciation and amortization expense	**77,288**	71,076	9%
Goodwill impairment	**206,465**	-	100%
Earnings (loss) From Operations[1]	**(173,300)**	14,125	(133%)
Cash capital expenditures	**43,875**	56,162	(21%)
Feedstock volume (bbl/d)[2]	**83,939**	103,497	(19%)
Yield (000's barrels)			
Gasoline and related products	**10,499**	12,068	(13%)
Ultra low sulphur diesel and jet fuel	**12,196**	15,668	(22%)
HSFO	**7,538**	9,952	(24%)
Total	**30,233**	37,688	(20%)
Average refining margin (US$/bbl)[3]	**9.12**	7.16	27%

[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 ("VGO").
[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 $2.4 million for the year ended December 31, 2009 ($35.3 million for the year ended December 31, 2008).

Overview of Downstream Operations

Our Downstream operations are composed of a 115,000 bpd 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 composed of branded and unbranded retail and wholesale distribution and sales of gasoline, diesel, jet and other transportation fuels, as well as home heating fuels and related appliances and the revenues from our marine services businesses.

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 and other feedstocks purchased as well as the yield of refined products from various feedstocks. We continuously evaluate the market and relative refinery values of several different crude oils and vacuum gas oils ("VGO") to determine the optimal feedstock mix. We analyze the refining margin for each refined product as well as our sales revenue relative to refined product benchmark prices 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 for reporting.

In 2009 we purchased substantially all of our refinery feedstock and sold 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 ("SOA"). Throughout 2008 and 2009, our High Surphur Fuel Oil ("HSFO") was sold to a wholly-owned affiliate of one of the world's largest integrated energy companies. Effective November 1, 2009 Harvest announced a renewal of an amended SOA with Vitol for a primary term of two years after which the agreement will revert to evergreen. Under this renewed and amended SOA, our HSFO will be sold to Vitol. During the year ended December 31, 2009, approximately 62% of our refined product sales were to Vitol (67% during the year ended December 31, 2008).

The SOA 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 SOA with Vitol, see the description in our Annual Information Form for the year ended December 31, 2008 as filed on SEDAR at www.sedar.com; a description of the amendments discussed above will be included in our Annual Information Form for the year ended December 31, 2009 to be filed on SEDAR.

For the year ended December 31, 2009, our refining gross margin was $317.7 million as compared to $287.6 million in the prior year, an increase of $30.1 million. The increase in refining gross margin is primarily due to stronger gasoline and HSFO margins, which resulted in positive price variances of $74.0 million and $145.6 million, respectively, partially offset by reduced distillate margins, which resulted in a negative price variance of $254.7 million.

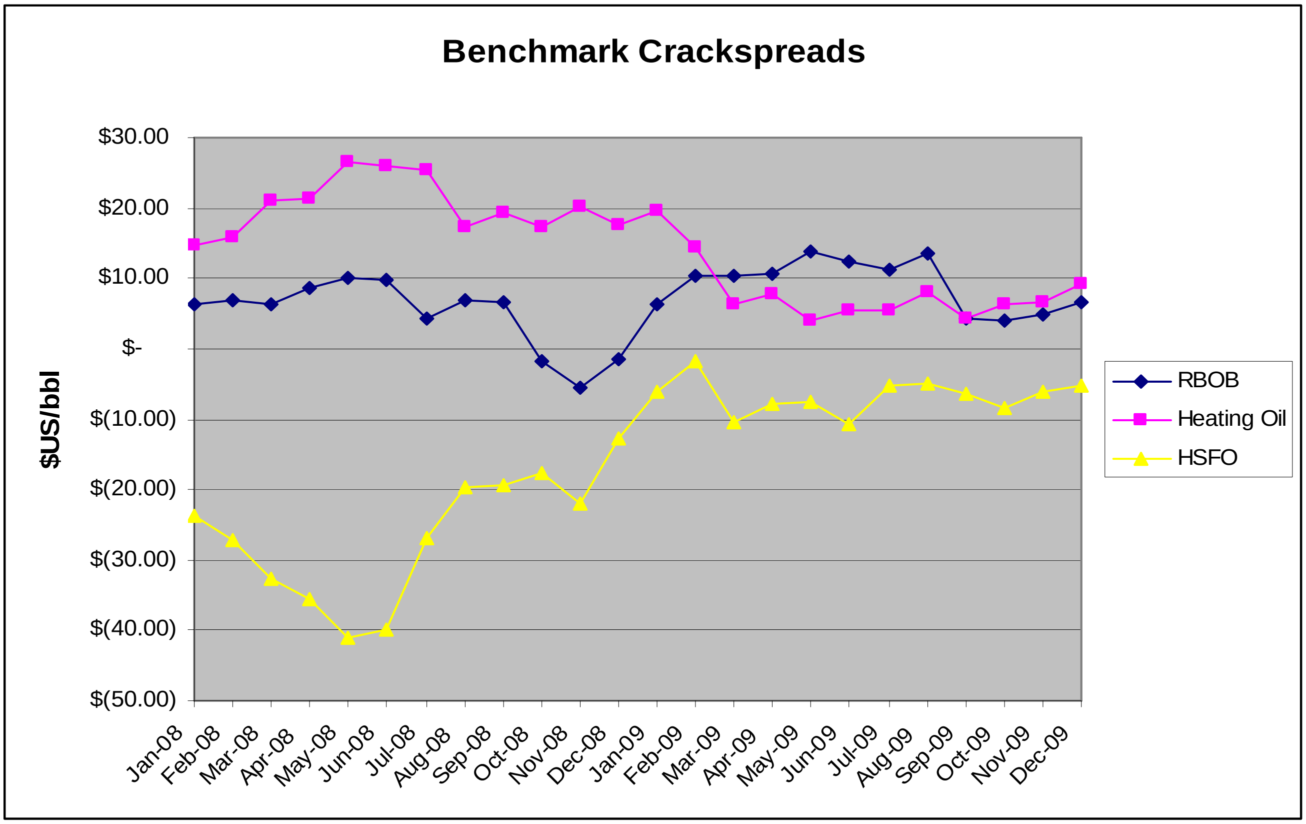
For the year ended December 31, 2009, our marketing division earned a gross margin of $48.2 million as compared to $56.5 million in the prior year. The $8.3 million decrease is mainly due to a significant decrease in the price of sulphur, which is sold through a profit sharing agreement with a third party processor and which contributed nil million in 2009 as compared with $8.5 million in 2008 .

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		
	2009	2008	Change
WTI crude oil (US$/bbl)	**61.80**	99.65	(38%)
Brent crude oil (US$/bbl)	**62.50**	98.38	(36%)
Basrah Official Sales Price ("OSP") Discount (US$/bbl)	**(3.23)**	(7.40)	(56%)
RBOB gasoline (US$/bbl / US$/gallon)	**70.86/1.69**	104.40/2.49	(32%)
Heating Oil (US$/bbl / $US/gallon)	**69.93/1.67**	119.89/2.85	(42%)
HSFO (US$/bbl)	**55.07**	73.13	(25%)
Canadian / U.S. dollar exchange rate	**0.880**	0.943	(7%)

The following graph summarizes the WTI crack spreads for the respective benchmark product prices for the period of January 2008 through December 2009:



During 2009, the Heating Oil Crack Spread averaged US$8.13/bbl, a decrease of US$12.11/bbl over the US$20.24/bbl averaged in the prior year, as previously strong demand for distillate products in North America, Europe and Asia decreased, reducing margins. The RBOB Gasoline Crack Spread averaged US$9.06/bbl in 2009, an improvement of US$4.31/bbl from the US$4.75/bbl averaged in the prior year, as North American refinery output was curtailed to balance the continued weak demand resulting from the slowdown in economic activity. Similarly, the HSFO Crack Spread differential averaged US$6.73/bbl less than WTI in 2009, an increase of US$19.79/bbl from the average differential of US$26.52/bbl less than WTI in the prior year, as the prices of heavy sour crude oils improved substantially in the fourth quarter of 2008 and remained relatively stable throughout 2009.

During 2009, the Canadian/U.S. dollar exchange rate averaged $0.880, a decrease of $0.063 from the prior year. The relative weakening of the Canadian dollar resulted in a nominal increase in our cash flows from Downstream operations in 2009, as refined product and crude oil prices are denominated in U.S. dollars.

Summary of Gross Margin

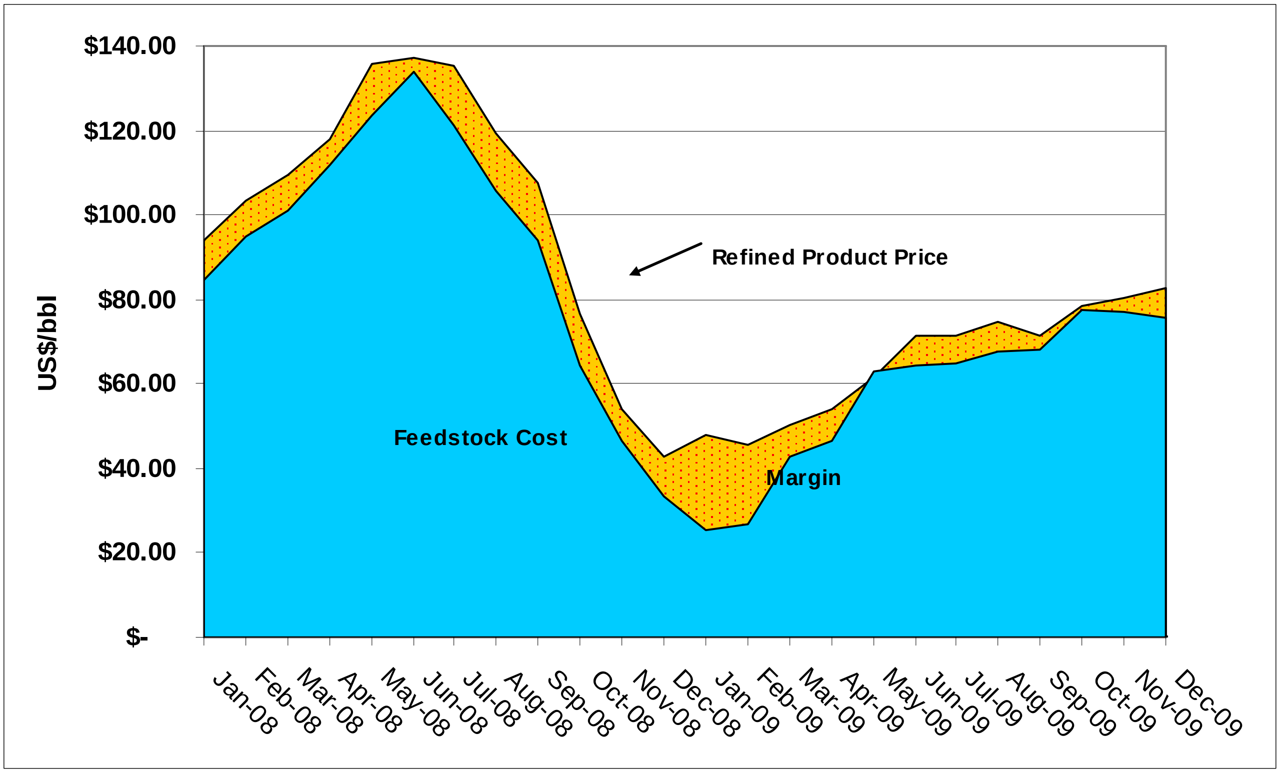
The following table summarizes our Downstream gross margin for the years ended December 31, 2009 and 2008 segregated between refining activities and petroleum marketing and other related businesses.

	Year Ended December 31					
	2009			2008		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Sales revenue[1]	**2,291,971**	**479,930**	**2,381,637**	4,092,555	670,686	4,194,595
Cost of feedstock for processing and products for resale[1]	**1,974,223**	**431,714**	**2,015,671**	3,804,952	614,201	3,850,507
Gross margin[2]	**317,748**	**48,216**	**365,966**	287,603	56,485	344,088
Average refining margin (US$/bbl)	**9.12**			7.16		

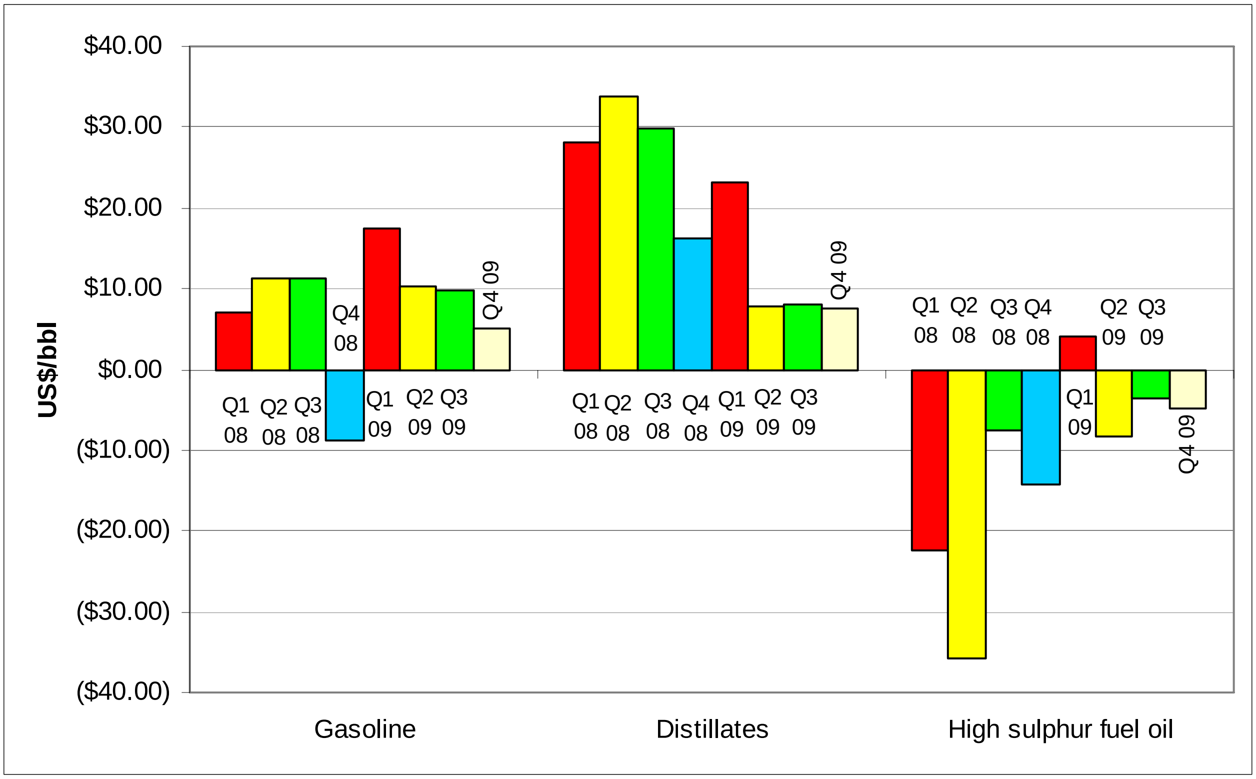
[1] Downstream sales revenue and cost of products for processing and resale are net of intra-segment sales of $390.3 million for the year ended December 31, 2009 (2008 - $568.6 million) reflecting the refined products produced by the refinery and sold by the Marketing Division.
[2] This is a non-GAAP 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 2008 to December 2009:



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

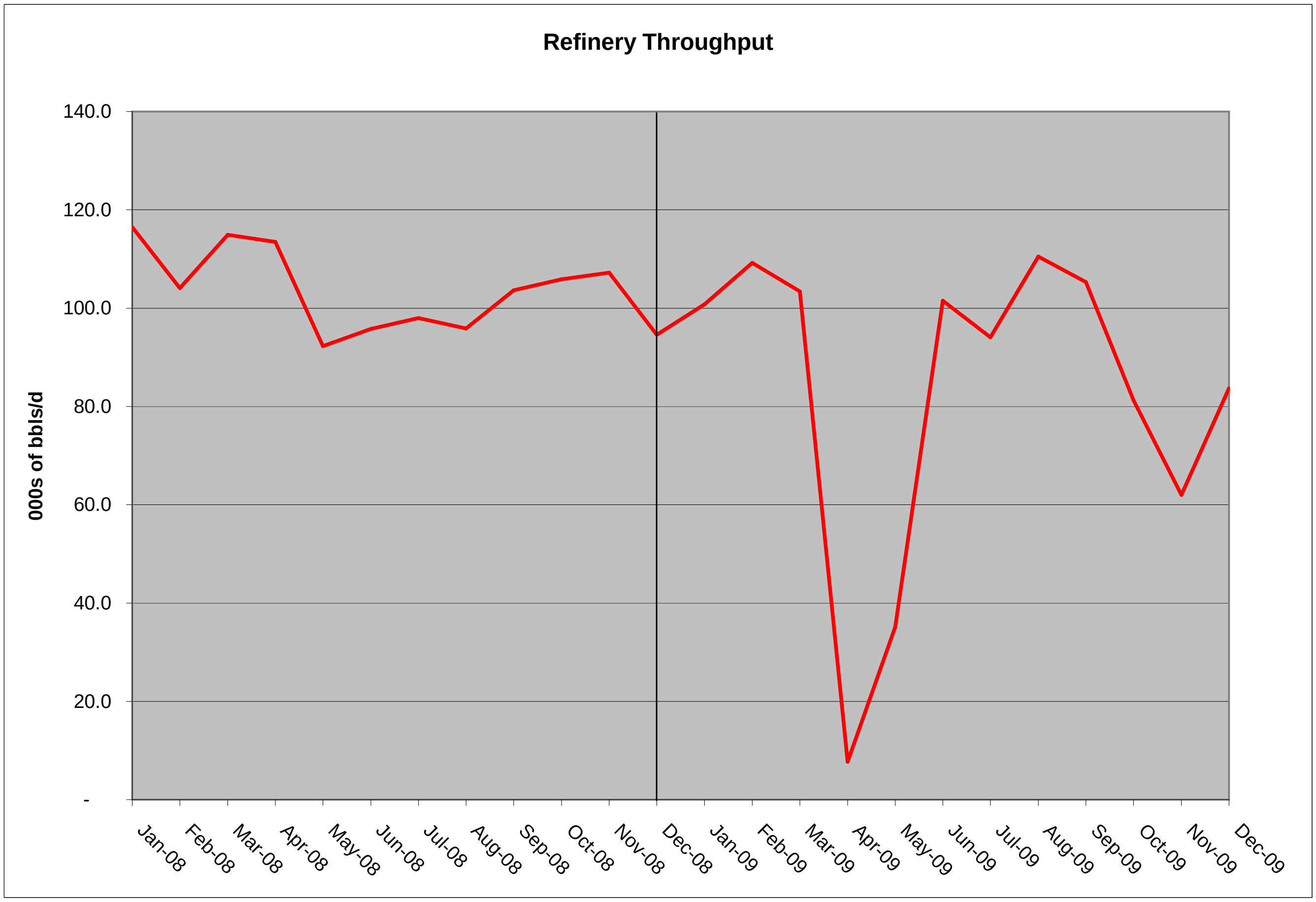


Throughout 2008, refining margins averaged US$7.16/bbl, as crack spreads were particularly strong for distillate products with distillate margins averaging US$29.91/bbl for the year, while gasoline and HSFO crack spreads were relatively weak averaging US$6.68/bbl and US$(16.78)/bbl, respectively, reflecting increased feedstock costs and decreasing consumer demand for gasoline products particularly in the Fourth Quarter 2008.

In 2009, gasoline and HSFO margins improved over the prior year, while distillate margins softened considerably resulting in an average refining margin of US$9.12/bbl. This US$1.96/bbl improvement over the prior year reflects the US $14.40/bbl improvement in HSFO margins from US$(16.78)/bbl to US$(2.38)bbl, particularly in the First Quarter of 2009 when the HSFO margin was positive US$4.20/bbl, reflecting improved margins on these lower valued petroleum products. Similarly, gasoline margins improved by US$4.63/bbl to US$11.31/bbl in 2009. These margin improvements were offset by a US$16.31/bbl decrease in distillate margins from US$29.91/bbl in 2008 to US$13.60/bbl in 2009.

Refinery Throughput

The throughput of our refinery for the period of January 2008 to December 2009 is illustrated below in thousands of barrels of feedstock per day:



During 2009, our feedstock was composed of 78,367 bpd of medium sour crude oil and 5,571 bpd of VGO as compared to 93,697 bpd of crude oil and 9,800 bpd of VGO in the prior year. Our aggregate total throughput in 2009 was 83,939 bpd, a 19,558 bpd decrease over the prior year reflecting a utilization rate of 73% relative to a 115,000 bpd nameplate capacity. Relative to 2008, refinery throughput was 19% lower, primarily attributed to a 42-day planned turnaround in the Second Quarter of 2009 coupled with the planned reduction in throughput in the Fourth Quarter of 2009 to optimize refinery economics in response to changing market conditions and to conduct some planned maintenance on the crude and platformer units. The planned turnaround was performed on the hydrocracking and hydrogen units and saw replacement of distillate hydrotreating and hydrocracking catalyst, as well as regeneration of the naphtha reforming unit catalyst, after which the refinery returned to near-capacity throughput for most of the Third Quarter. The refinery experienced limited planned or unplanned downtime in 2008, though 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.

Refinery Sales Revenue

A comparison of our refinery yield, product pricing and revenue for the years ended December 31, 2009 and 2008 is presented below:

	Year Ended December 31					
	2009			2008		
	Refinery Revenues	**Volume**	**Sales Price**	Refinery Revenues	Volume	Sales Price[1]
	(000's of Cdn $)	(000's of bbls)	(US$ per bbl/ US$ per US gal)	(000's of Cdn $)	(000's of bbls)	(US$ per bbl/ US$ per US gal)
Gasoline products	**851,850**	**11,014**	**68.06/1.62**	1,327,599	12,830	97.58/2.32
Distillates	**972,872**	**12,169**	**70.35/1.68**	2,006,406	15,661	120.81/2.88
HSFO	**467,249**	**7,563**	**54.37**	758,550	9,651	74.12
	2,291,971	**30,746**	**65.60**	4,092,555	38,142	101.18
Inventory adjustment		**(513)**			(454)	
Total production		**30,233**			37,688	
Yield (as a % of Feedstock)		**98.7%**			99.7%	

For the year ended December 31, 2009, our refinery yield was composed of 35% gasoline products, 40% distillates and 25% HSFO compared to 32%, 42% and 26% for the same products during 2008. 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. The shift in product yield in 2009 from distillates to gasoline is attributed to end-of-run activity of the hydrocracker catalyst as well as other end-of-run conditions in the First Quarter 2009 prior to the scheduled turnaround completed in the Second Quarter of 2009 as well as operational and feedstock changes to capitalize on the improved gasoline margins in 2009.

Relative to the average WTI benchmark price, in 2009 our refined products sold at an average premium of US$2.27/bbl higher than in the prior year. In 2009, our average sales price was US$65.60/bbl (a premium of US$3.80/bbl over WTI) as compared to an average selling price of US$101.18/bbl in the prior year (a premium of US$1.53/bbl over WTI). This increase in premium represents a $79.3 million price variance in 2009.

During 2009, the average sales premium to the average WTI benchmark price for our gasoline was US$6.26/bbl as compared to a US$2.07/bbl discount to WTI realized in 2008 representing a $104.3 million increase in gross margin as compared to the prior year. This US$8.33 improvement in gasoline refining margins relative to WTI reflects the reduction in North American refinery gasoline output to balance the continued weak demand resulting from the slowdown in economic activity.

During 2009, the average sales premium to the average WTI benchmark price for our distillate products was US$8.55/bbl as compared to a US$21.16/bbl premium over WTI realized in 2008 representing a $174.4 million decrease in gross margin as compared to the prior year. During 2009, global demand for distillate products weakened relative to the prior year resulting in poorer relative margins. As well, in 2009 the generally weaker margins for distillates were partially offset by US$0.7 million of incremental revenue from delivering approximately 2.7 million barrels of distillate products to Europe pursuant to our profit sharing arrangement with Vitol (in 2008 US$7.9 million of incremental revenue from delivery of approximately 7.5 million barrels).

During 2009, the average sales discount to the average WTI benchmark price for our HSFO was US$7.43/bbl as compared to a US$25.53/bbl discount in 2008 representing a $155.6 million improvement in gross margin as compared to the prior year. The US$18.10/bbl improvement in our HSFO pricing relative to WTI reflects the US$19.79/bbl improvement in the HSFO benchmark crack spread.

Refinery Feedstock

The volatility of WTI prices throughout 2009 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 processes international waterborne crude oils and VGO's and the WTI benchmark price generally reflects a land-locked North American price with limited access to the international markets.

The cost of our feedstocks 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 SOA and, for our Iraqi crude oil purchases, the Official Selling Price ("OSP") as set by the Oil Marketing Company of the Republic of Iraq. On a monthly basis, the OSP is announced as a discount to the WTI benchmark price for North American deliveries and is influenced by the quality of the crude oil as well as by the demand from contract purchasers in other regions.

A comparison of crude oil and VGO feedstock processed for the years ended December 31, 2009 and 2008 is presented below:

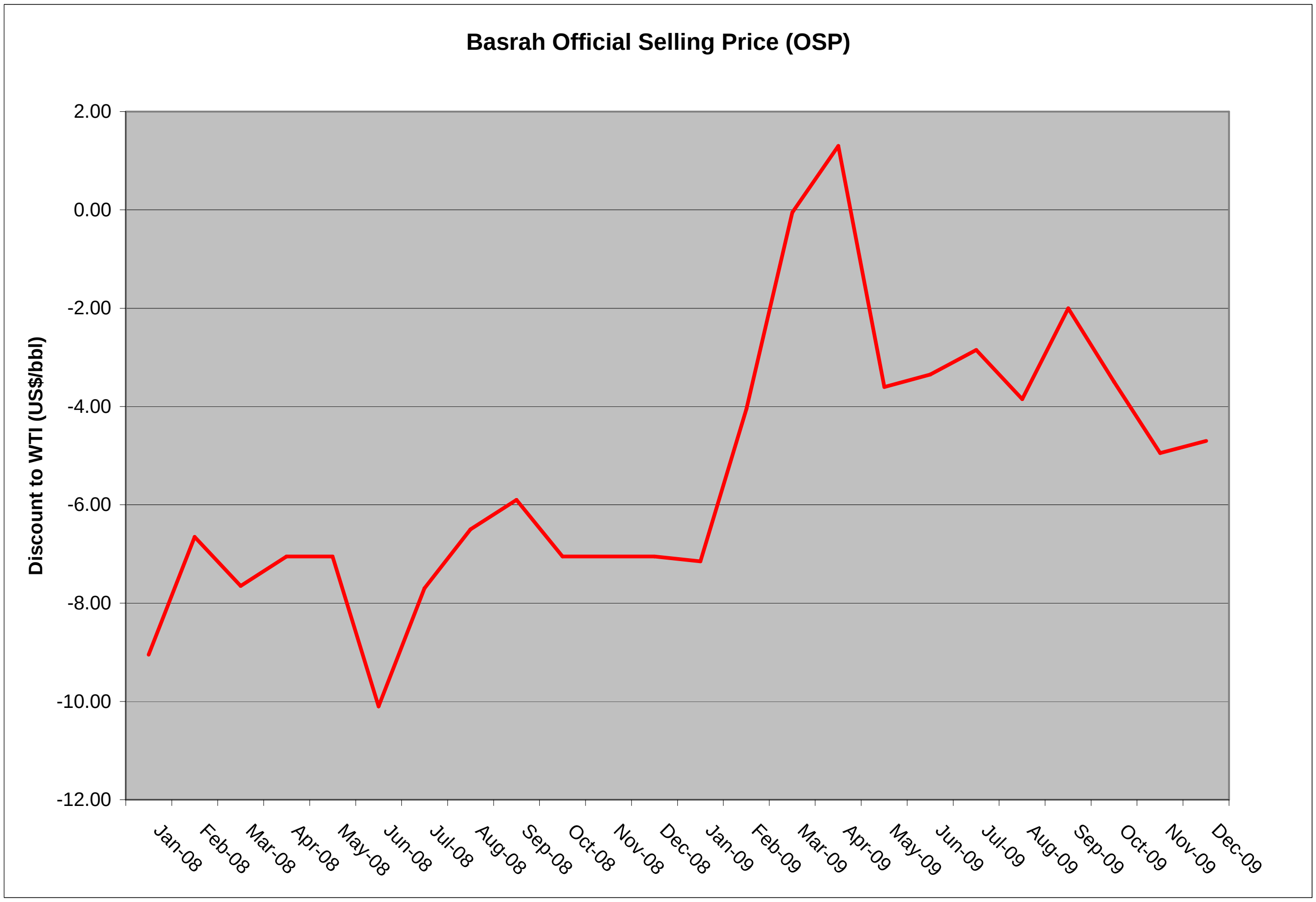
	Year Ended December 31					
	2009			2008		
	Cost of Feedstock	**Volume**	**Cost per Barrel [1]**	Cost of Feedstock	Volume	Cost per Barrel [1]
	(000's of Cdn $)	(000's of bbls)	(US$/bbl)	(000's of Cdn $)	(000's of bbls)	(US$/bbl)
Iraqi	**1,132,066**	**18,098**	**55.05**	1,963,882	21,218	87.28
Russian	**437,386**	**5,816**	**66.18**	614,187	5,973	96.97
Venezuelan	**260,456**	**4,690**	**48.87**	676,777	7,102	89.86
Crude Oil Feedstock	**1,829,908**	**28,604**	**56.30**	3,254,846	34,293	89.50
VGO	**145,806**	**2,033**	**63.11**	396,676	3,586	104.31
	1,975,714	**30,637**	**56.75**	3,651,522	37,879	90.90
Net inventory adjustment [2]	**(28,183)**			(8,990)		
Additives and blendstocks	**33,971**			127,136		
Inventory write-down (recovery) [3]	**(7,279)**			35,284		
	1,974,223			3,804,952		

[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.

The following graph illustrates the volatility of the Basrah Light OSP discount to WTI since January 2008, which relative to our US$9.12 average refining margin for 2009 is a significant factor to our Downstream financial performance:



Although the OSP discount may change between the date of loading in Iraq and its eventual processing 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$4.05 in February 2009 was a component of the cost of our feedstock processed in April and May recognizing the 30 to 45 days required to load in Iraq, transport to our refinery in Newfoundland, and storage residence time before processing. Although the SOA provides for operational hedging of the risk of WTI price variations between the time of pricing of our feedstocks and the time of processing, we are not able to hedge or otherwise manage the basis risk to WTI price associated with the medium sour crude oils we typically process.

When we commit to crude oil purchases, Vitol sells a forward WTI price contract for the appropriate futures contract month, which results in cash market price fluctuations subsequent to our purchase commitment being offset by the price fluctuations of the futures contract. If the crude oil is not processed before the expiration of the forward contract, the volume of the forward contract relating to unprocessed crude oil is rolled to the next futures contract month. This practice results in better matching of our refined product sales prices with our cost of feedstock. The persistent contango shape of the NYMEX WTI futures price curve since October 2008 has resulted in operational hedging gains from the rolling forward of these price contracts, which reduced our feedstock costs in the month the feedstock is processed. During 2009, this operational hedging resulted in reductions to the cost of our feedstock of US$73.2 million, as compared to the prior year when this operational hedging resulted in reductions to the cost of feedstock of US$0.4 million.

The cost of our crude oil feedstock averaged US$56.30/bbl during 2009 representing a US$5.50/bbl discount from WTI as compared to a cost of US$89.50/bbl and a discount of US$10.15/bbl in the prior year. The US$5.50 discount is composed of a US$3.07/bbl quality discount (2008 – US$6.30/bbl) and a US$2.35/bbl operational hedging gain (2008 – US$0.01/bbl) offset by a US$0.08/bbl reduction relating to timing under the SOA (2008 – US$3.83/bbl).

The average cost of purchased VGO during 2009 was US$63.11/bbl representing a premium of US$1.31/bbl relative to the WTI benchmark price as compared to US$104.31/bbl and a US$4.66/bbl premium in the prior year. The reduced premium in 2009 is attributed to reduced demand for VGO as a consequence of reduced gasoline demand coupled with the benefit of our operational hedging.

Operating Expenses

The following summarizes the operating costs from the refinery and marketing division for the years ended December 31, 2009 and 2008:

	Year Ended December 31					
	2009			2008		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Operating expense	**82,888**	**19,668**	**102,556**	78,907	19,829	98,736
Turnaround and catalyst	**47,487**	**-**	**47,487**	5,645	-	5,645
Purchased energy	**91,868**	**-**	**91,868**	131,878	-	131,878
	222,243	**19,668**	**241,911**	216,430	19,829	236,259

The largest component of refining operating expense is wages, salaries and benefits which totaled $49.3 million during 2009 (2008 - $49.6 million) while the other significant components were maintenance and repair costs of $15.0 million (2008 - $13.2 million), insurance of $6.2 million (2008 - $5.7 million) and professional services of $3.5 million (2008 - $5.1 million). Refining operating expenses were $2.71/bbl during the year as compared to $2.08/bbl in 2008 reflecting decreased throughput and an increase in total refining operating expenses, particularly repair and maintenance costs. The marketing division's operating expenses have remained relatively unchanged from the prior year.

Turnaround and catalyst expenditures for the year ended December 31, 2009 of $47.5 million relate to costs incurred in preparation for, and completion of, the scheduled turnaround in the Second Quarter of 2009 of the hydrocracking and hydrogen units, replacement of distillate hydrotreating and hydrocracking catalyst and the regeneration of the naptha reforming unit catalyst. Of the total costs incurred related to the turnaround, $21.5 million relates to catalyst replacement and regeneration expenditures, while the balance relates to other turnaround activities. Harvest's accounting policy is to expense all turnaround and catalyst replacement and regeneration expenditures, while capitalizing projects that provide future economic benefit. Turnaround and catalyst expenditures incurred in 2008 of $5.6 million relate to planned equipment certifications scheduled during the shutdown to implement the visbreaker unit expansion project.

Purchased energy, consisting of low sulphur fuel oil ("LSFO") and electricity, is required to provide heat and power to refinery operations. Our purchased energy for the year ended December 31, 2009 was $3.00/bbl of throughput as compared to $3.48/bbl for 2008. In 2009, we purchased approximately 1.3 million barrels of LSFO at an average price of US$56.80/bbl as compared to approximately 1.6 million barrels purchased in 2008 at an average price of US$72.79/bbl. The $38.9 million decrease in the cost of purchased LSFO is due to a $21.3 million decreased price variance and a $17.6 million decrease in volume consumed. Our electricity costs decreased during the year at $9.0 million as compared to $10.1 million in the prior year, a result of reduced average throughput.

Marketing Expense and Other

During the year ended December 31, 2009, marketing expense was composed of $2.9 million (2008 - $3.4 million) of marketing fees (based on US$0.08/bbl) to acquire feedstock and $9.1 million (2008 - $26.0 million) of time value of money (TVM") charges both pursuant to the terms of the SOA. The decreased TVM charge is mainly the result of a reduced crude oil inventory investment associated with lower commodity prices. At December 31, 2009, Harvest had commitments totaling approximately $582.1 million in respect of future crude oil feedstock purchases and related transportation from Vitol.

Capital Expenditures

Capital spending for the year ended December 31, 2009 totaled $43.9 million (2008 - $56.2 million) relating to various capital improvement projects including $11.2 million associated with the debottleneck projects.

Depreciation and Amortization Expense

The following summarizes the depreciation and amortization expense for the years ended December 31, 2009 and 2008:

	Year Ended December 31					
	2009			2008		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Tangible assets	**67,619**	**3,262**	**70,881**	62,383	2,555	64,938
Intangible assets	**5,080**	**1,327**	**6,407**	4,749	1,389	6,138
	72,699	**4,589**	**77,288**	67,132	3,944	71,076

The process units are amortized over an average useful life of 15 to 25 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 end of period 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.

At June 30, 2009, it was determined that an impairment test was required due to expectations of lower refining gross margins and the probable deferral of certain future capital expenditures. The fair value of the Downstream reporting unit was determined using a discounted cash flow approach which incorporated management's expectations of future throughput and expenses and the forward curve for refined product crack spreads. At June 30, the fair value of the Downstream reporting unit was below its carrying value, indicating a potential impairment. The fair value of the Downstream goodwill was determined by valuing the reporting unit's net assets in the same manner as allocating a purchase price in a business combination. As the carrying value of the reporting unit's goodwill exceeded its fair value, it was determined that the goodwill associated with the Downstream reporting unit was fully impaired. Accordingly, a charge of $206.5 million was recorded in the financial results for the year ended December 31, 2009.

RISK MANAGEMENT, FINANCING AND OTHER

Cash Flow Risk Management

Harvest employs an integrated approach to cash flow risk management strategies whereby 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 2010 cash flow at risk is comprised of approximately 32,000 bbls/d of refined product price exposure, 57,000 bbls/d of refined product crack spread exposure and 68,000 mcf/d of net 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. The table below provides a summary of the gains and losses realized on our price risk management contracts for the years ended December 31, 2009 and 2008:

	Year Ended December 31		
(000's)	**2009**	2008	Change
Crude oil	**$-**	$(36,625)	100%
Refined product	**45,705**	(174,129)	126%
Natural gas	**(129)**	(381)	66%
Currency exchange rates	**18,492**	401	4,511%
Electric Power	**(1,265)**	9,952	(113%)
Total realized gain (loss)	**$62,803**	$(200,782)	131%

During 2009, our net realized gain on price risk management contracts was $62.8 million (2008 – loss of $200.8 million), an increase of $263.6 million over the prior year, primarily due to gains on our refined product pricing contracts of $45.7 million (2008 – loss of $174.1 million), as well as increased gains on our currency exchange contracts. Additionally, Harvest did not have any crude oil contracts in place throughout 2009 as compared to having losses on crude oil contracts totaling $36.6 million in 2008.

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 for the first six months of 2009. The cash settlements of these contracts aggregated to $35.2 million and $10.5 million, respectively, during the year.

We had contracted to fix the US/Canadian dollar exchange rate for the period July 2009 through December 2009 on US$15.0 million per month at an average of Cdn$1.282 per US $1.00. Harvest received $18.5 million in settlements on this contract during the year.

During the First Quarter of 2009 we entered into a fixed price power contract for 10 MWh at $61.90 per MWh for the period of April 2009 through December 2009. This contract resulted in losses of $1.3 million as the Alberta electric power prices averaged $47.85 per MWh during the period. The fixed price contract ended in December 2009. Beginning January 2010, we have contracted to fix 25 MWh at an average of $59.22 through December 2010.

As of December 31, 2009, the mark-to-market defficiency on our fixed price power contracts was $2.1 million. We had no contracts for WTI, refined products, natural gas or currency exchange at the end of December 2009. 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, 2009 filed on SEDAR at www.sedar.com.

Interest Expense

	Year Ended December 31		
(000's)	**2009**	2008	Change
Interest on short term debt			
Bank loan	**$ 8,747**	$ -	100%
Convertible Debentures	**149**	295	(49%)
Amortization of deferred finance charges – short term debt	**-**	-	n/a
	8,896	295	2916%
Interest on long-term debt			
Bank loan	**7,835**	51,855	(85%)
Convertible Debentures	**77,765**	69,159	12%
$7^{7/8}$% Senior Notes	**24,413**	22,662	8%
Amortization of deferred finance charges – long term debt	**930**	2,699	(66%)
	110,943	146,375	(24%)
Total interest expense	**$ 119,839**	$ 146,670	(18%)

Interest expense, including the amortization of related financing costs, decreased $26.8 million (18%) compared to the prior year as interest on our bank borrowings has decreased by $35.3 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 between 70 to 75 basis points over bankers' acceptances for Canadian dollar borrowings. During the year, interest charges on bank loans reflected an effective interest rate of 1.44%. Further details on our credit facilities are included under "Liquidity and Capital Resources" and Note 11 to the audited consolidated financial statements for the year ended December 31, 2009 filed on SEDAR at www.sedar.com.

The interest on our Convertible Debentures totaled $77.9 million during 2009, representing a $8.5 million increase over the prior year. The increase is due to the impact of the four additional months of interest on the 7.5% Convertible Debenture issued on April 25, 2008. Details on the Convertible Debentures outstanding are fully described in Note 13 to the audited consolidated financial statements for the year ended December 31, 2009 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 77/8% Senior Notes totaled $24.4 million for the year ended December 31, 2009. 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 77/8% 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 $0.9 million for the year ended December 31, 2009.

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 77/8% Senior Notes as well as any other U.S. dollar cash balances. Realized foreign exchange losses of $3.1 million for 2009, have resulted from the settlement of U.S. dollar denominated transactions. Since December 31, 2008, the Canadian dollar has strengthened compared to the U.S dollar from 1.218 to a rate of 1.051 at December 31, 2009, resulting in a year-to-date unrealized foreign exchange gain of $5.3 million. Of this unrealized gain, $41.0 million relates to the 77/8% Senior Notes, offset by $35.9 million of unrealized foreign exchange loss 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 2009, the strengthening of the Canadian dollar relative to the U.S. dollar resulted in a $172.1 million net cumulative translation gain (2008 – net gain of $284.7 million) as the stronger U.S. dollar results in an increase in the relative value of the net assets in our downstream operations.

KNOC Acquisition Related Costs

Harvest incurred $18.4 million of costs relating to the acquisition of Harvest Trust Units by KNOC which includes $13.6 for advisory services, $2.6 million for management contract payouts and $2.2 million for the settlement of the Trust Unit Rights Incentive Plan and the Unit Award Plan.

Future Income Tax

During 2009, there was a significant change in the corporate structure of Harvest that impacted our accounting for future income taxes. As a result of the acquisition by KNOC on December 22, 2009, Harvest is no longer a public trust and is therefore no longer subject to the SIFT tax legislation that passed in Bill C-52 in June 2007 which made the distributions of publicly traded trusts subject to tax. Management does not intend on having income accumulate in the trust; however, in the event that this occurred, tax free distributions could be made to KNOC Canada to eliminate any taxable income. This results in an effective tax rate of zero for Harvest's flow through entities which led to a reversal of the remaining future tax liability that was initially booked upon the enactment of the SIFT rates in the second quarter of 2007. A recovery of $224.7 million relating to this reversal was realized through equity during 2009 as it arose from a change in shareholder status, while a recovery of $28 million was reflected in the income statement. The additional movement was due to a future tax asset of $15 million being recorded on the Pegasus acquisition.

At the end of 2009, Harvest had a net future income tax asset on the balance sheet of $64.8 million, comprised of a $91 million future income tax liability for the downstream corporate entities and an offsetting future income tax asset of $155.8 million for the upstream corporate entities. This compares to a future income tax liability of $204 million at the end of the prior year, comprised of a $372.6 million provision for our various flow through entities and a $168.6 million net asset for our corporate entities.

At the end of 2009, we estimated our unclaimed capital expenditures to be:

Tax Classification (in millions)	Trust	Upstream Operations	Downstream Operations	Total
Canadian Oil & Gas Property Expenditures	$ 487.0	$ 313.2	$ -	$ 800.2
Canadian Development & Exploration Expenditures	-	309.9	-	309.9
Unclaimed Capital Costs	-	361.3	314.3	675.6
Non-capital losses and other	25.1	823.6	317.3	1,166.0
Total	$ 512.1	$ 1,808.0	$ 631.6	$ 2,951.7

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 we have now scheduled the examinations for discovery for early April 2010.

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, 2009.

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 *(000's)*	**Total**	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt[1]	**$ 1,604,934**	$ 650,687	$ 327,050	$ 390,598	$ 236,599
Interest on long-term debt[1]	**259,367**	75,404	118,277	58,394	7,292
Operating and premise leases	**34,325**	6,506	14,329	12,331	1,159
Purchase commitments[2]	**20,990**	19,173	1,817	-	-
Asset retirement obligations[3]	**1,201,615**	12,178	40,071	25,893	1,123,473
Transportation [4]	**5,661**	3,131	2,325	205	-
Pension contributions[5]	**25,864**	4,100	8,448	8,789	4,527
Feedstock commitments	**582,050**	582,050	-	-	-
Total	**$ 3,734,806**	$ 1,353,229	$ 512,317	$ 496,210	$ 1,373,050

(1) Assumes constant foreign exchange rate.
(2) Relates to drilling commitments, AFE commitments and downstream purchase commitments.
(3) Represents the undiscounted obligation by period.
(4) Relates to firm transportation commitment on the Nova pipeline.
(5) 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, 2009 and December 31, 2008, we have no off balance sheet arrangements in place.

Change In Accounting Policies

Effective December 31, 2009, Harvest adopted CICA issued amendments to Handbook Section 3862, Financial Instruments – Disclosures. The amendments include enhanced disclosures relating to the fair value of financial instruments and the liquidity risk associated with financial instruments. Section 3862 now requires that all financial instruments measured at fair value be categorized into one of three hierarchy levels. Refer to Note 20 Financial Instruments and Risk Management for enhanced fair value disclosures and liquidity risk disclosures.

Effective January 1, 2009, Harvest adopted the new Canadian Institute of Chartered Accountants ("CICA") accounting standard "Goodwill and Intangible Assets", Section 3064 which replaced Section 3062 "Goodwill and Other Intangible Assets" and Section 3450, "Research and Development Costs". Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of intangible assets and goodwill subsequent to its initial recognition. The adoption of this standard had no impact on the consolidated financial statements.

DISTRIBUTIONS TO UNITHOLDERS

Harvest has historically declared monthly distributions to Unitholders based upon expectations of cash from operating activities, capital expenditure plans and debt repayment requirements. However, subsequent to the closing of the Arrangment on December 22, 2009, KNOC now owns all the issued and outstanding Trust Units and we no longer intend to declare regular monthly distributions.

In 2009, we declared distributions to Unitholders totaling $164.8 million ($1.00 per Trust Unit) representing 35% of our cash flow from operating activities as compared to $551.3 million ($3.60 per Trust Unit) representing 84% of our cash flow from operating activities in 2008. This decrease in distributions is due to a change in our monthly distribution from $0.30 per Trust Unit to $0.05 per Trust Unit commencing in March 2009, as well as no distributions being declared for the final two months of 2009 as a result of the Arrangement with KNOC.

In 2009, our distributions exceeded our net income by $1,100.4 million compared to $339.3 million in 2008. 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, such as depletion, depreciation, amortization and accretion, unrealized gains/losses on risk management contracts, future income tax expense/recovery and goodwill impairments.

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		
(000's except per trust unit amounts)	**2009**	2008	Change
Cash from Operating Activities	**$ 473,602**	$ 655,877	(28%)
Net Income (Loss)	**$ (935,634)**	$ 212,019	(541%)
Distributions declared	**$ 164,770**	$ 551,325	(70%)
Per trust unit	**$ 1.00**	$ 3.60	(72%)
Distribution reinvestment proceeds	**$ 43,717**	$ 137,974	(68%)
Distributions as a percentage of cash from operating activities	**35%**	84%	(49%)

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 minor 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 incremental debt and capital injections from KNOC. Should incremental debt not be available to us through debt capital markets, our ability to make the necessary expenditures to maintain or expand our assets may be impaired. 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.

The economic downturn has reduced demand for commodities and lower prices as well as liquidity concerns in financial markets with a tightening of capital availability and higher costs for new credit commitments. These conditions have significantly impacted our cash flow from operating activities and have resulted in our access to capital markets becoming more difficult. During the latter part of 2009 we have seen an improvement in the price of oil and in the liquidity of the debt capital markets.

On December 22, 2009, Korea National Oil Corporation ("KNOC") acquired all of the issued and outstanding Trust Units of Harvest at a price of $10.00 per Trust Unit for an aggregate cash consideration of approximately $1.8 billion plus the assumption of approximately $2.3 billion of debt through its wholly owned Canadian subsidiary, KNOC Canada Ltd. The capital structure of Harvest was impacted by the covenants and conditions of our Revolving Credit Facility, 77/8% Senior Notes and Convertible Debenture agreements as a result of this transaction, each of which is explained in more detail below.

The following table summarizes our capital structure as at December 31, 2009 and 2008:

	As At December 31	
DEBT *(in millions)*	**2009**	2008
Extendible Revolving Credit Facility	**$428.0**	$1,226.2
$7^{7/8}$% Senior Notes Due 2011 (US$250 million)(1)	**262.8**	304.5
Convertible Debentures, at principal amount	**914.2**	916.7
Total Debt	**1,605.0**	2,447.4
Unitholders' Equity, at book value less equity component of convertible debentures		
242,268,801 issued at December 31, 2009	**2,367.5**	2,559.2
157,200,701 issued at December 31, 2008		
TOTAL CAPITALIZATION	**$3,972.5**	$5,006.6
FINANCIAL RATIOS		
Secured Debt to Annualized EBITDA(2)	**0.7**	1.5
Total Debt(3) to Annualized EBITDA(2)	**2.7**	1.8
Secured Debt to Total Capitalization	**11%**	25%
Total Debt to Total Capitalization	**40%**	31%

(1) Face value converted at the period end exchange rate.
(2) Annualized Earnings Before Interest, Taxes, Depreciation and Amortization based on twelve month rolling average.
(3) "Total Debt" includes the convertible debentures in 2009 due to the economic elimination of the conversion feature subsequent to the acquisition of Harevest Energy Trust by KNOC.

During 2009, cash flow from operating activities was $473.6 million including a $1.9 million increase in non-cash working capital as compared to $655.9 million including a $9.9 million increase in non-cash working capital in 2008. In 2009, we declared distributions of $164.8 million ($121.1 million net of our distribution re-investment plans) and required $230.2 million for capital expenditures which was partially offset by the $62.1 million received from our net acquisition and disposition activity resulting in a net cash requirement of $184.4 million. At the end of 2009, our bank borrowings totaled $428.0 million, a reduction of $798.2 million over the prior year.

During 2009, the principal change in our capital structure was as a result of an equity injection by KNOC; on December 22, 2009, KNOC acquired all of the outstanding Units of the Trust and in addition injected $600 million of equity to paydown existing borrowings under the Credit Facility. In January, 2010, KNOC injected a further $465.7 million of equity, also used to pay down borrowings under the credit facility. In addition, in June 2009 we used the net proceeds of $120.2 million from the issuance of 17,330,000 Trust Units to reduce our bank borrowings. With lesser impact, we elected to settle the maturity of $0.9 million principal amount of 9% Convertible Debentures on May 31, 2009 with the issuance of 136,906 Trust Units and a similar settlement of the maturing $1.6 million 8% Convertible Debentures on September 30, 2009 with 259,184 Trust Units rather than settling the obligations with cash. During 2009, we also issued 6,590,755 Trust Units pursuant to Harvest's Premium DistributionTM, Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "DRIP Plans") raising $43.7 million.

On December 22, 2009, the acquisition of all the outstanding and issued Trust Units of Harvest by KNOC triggered a Change of Control as defined under our $1.6 billion Extendible Revolving Credit Facility; this Change of Control required Harvest to make a number of amendments to the existing credit facility. An amended credit agreement was reached with eight of the original 14 lenders, maturing April 30, 2010 for a new commitment level of $600 million; Harvest is currently negotiating the renewal of this agreement. At the end of 2009, we had $172 million of unutilized borrowing capacity under our $600 million Extendible Revolving Credit Facility. For a complete description of our covenant-based credit agreement, see Note 11 to our audited consolidated financial statements for the year ended December 31, 2009.

In October 2004, Harvest Operations Corp., a wholly-owned subsidiary of Harvest, issued US$250 million of principal amount 77/8% Senior Notes and they remain outstanding at December 31, 2009. These 77/8% Senior Notes are unsecured, require semi-annual payments of interest and mature on October 15, 2011. Similar to the Revolving Credit Facility, our 77/8% Senior Notes contain a Change of Control covenant which was triggered by KNOC's purchase of Harvest's Trust Units. This covenant requires an Offer to Re-Purchase be made to the holders of the 77/8% Senior Notes at a price of 101% of the principal amount plus any accrued and unpaid interest to the date of repurchase. In addition, Harvest may call the 77/8% Senior Notes for redemption at a price of 101.969% of the principal amount plus any accrued and unpaid interest to the redemption date and effective October 15, 2010 and thereafter, at a price of 100% of the principal amount plus any accrued and unpaid interest to the redemption date. On January 20, 2010, Harvest made an offer to purchase 100% of the outstanding 77/8% Senior Notes for cash consideration of 101% of the principal amount thereof plus accrued and unpaid interest; on February 16, 2010, the offer relating to the 77/8% Senior Notes expired and US$40,434,000 principal amount was tendered, leaving a principal balance of US$209,566,000 outstanding.

The most restrictive covenant of the 77/8% 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 2009, 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.

With the announcement of Arrangement Agreement with KNOC, each of Moody's Investor Services ("Moody's) and Standard & Poor's Ratings Services (S&P) have placed Harvest's corporate rating of "B-" and "B3", respectively, and "CCC" and "Caa1", respectively, for the 77/8% Senior Notes under review for possible upgrade pending the completion of KNOC's acquisition of the Trust Units. KNOC is 100% owned by the Republic of Korea and has been rated as "A/Stable" by both Moody's and S&P.

At the end of 2009, we had $914.2 million of principal amount of Convertible Debentures issued in five series with maturity dates over the next six years. As a result of KNOC acquiring all of the outstanding Trust Units of Harvest at $10.00 per unit on December 22, 2009, the debentures are no longer convertible into Units but investors would receive $10.00 for each unit notionally received based on each series conversion rate. Because every series of debentures carry a conversion price that exceeds $10.00 per unit, it is assumed that no investor would exercise their conversion option. In addition, KNOC's acquisition of all Trust Units triggered the Change of Control mandatory offer to purchase all outstanding debentures at 101% of the principal amount within 21 to 30 days of the date of Change of Control.

Accordingly, on January 20, 2010, Harvest made an offer to purchase 100% of the outstanding Convertible Debentures for cash consideration of 101% of the principal amount thereof plus accrued and unpaid interest. The expiry date of each offer is as follows:

Series	Face Value at December 31, 2009	Carrying Value at December 31, 2009	Expiry Date of offer:
6.5% Debentures due 2010	37,062	36,187	March 4, 2010
6.4% Debentures due 2012	174,626	170,667	February 11, 2010
7.25% Debentures due 2013	379,256	362,216	March 4, 2010
7.25% Debentures due 2014	73,222	68,458	February 25, 2010
7.5% Debentures due 2015	250,000	200,342	February 25, 2010
	914,166	837,870	

As at March 4th, 2010 all of the offers have expired and the following redemptions have been made:

- 6.5% Debenture due 2010 – $13.3 million principal amount tendered leaving a principal balance of $23.8 million outstanding
- 6.4% Debenture due 2012 – $67.8 million principal amount tendered leaving a principal balance of $106.8 million outstanding
- 7.25% Debentures due 2013 - $48.7 million principal amount tendered leaving a principal balance of $330.5 million outstanding
- 7.25% Debentures due 2014 – $13.2 million principal amount tendered leaving a principal balance of $60.1 million outstanding
- 7.5% Debentures due 2015 – $13.4 million principal amount tendered leaving a principal balance of $236.6 million outstanding

In October 2009, North Atlantic Refinery Ltd. entered into an amended Supply and Offtake Agreement ("SOA") with Vitol Refining S. A. ("Vitol"), an international crude oil trading company, for an initial 2 year term effective November 1, 2009. This agreement requires the ownership of the crude oil and other feedstocks and substantially all of the refined product inventory at the refinery be retained by Vitol and also grants Vitol the exclusive rights and obligations to provide and deliver feedstock to the refinery and 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. The amendments increased the amount of working capital financing available, reduced the cost of financing inventory and other working capital, and increased the prices realized for product sales. For more information on the SOA, see the description in our Annual Information Form for the year ended December 31, 2008 as filed on SEDAR at www.sedar.com; a description of the amendments discussed above will be included in our Annual Information Form for the year ended December 31, 2009 to be filed on SEDAR. Pursuant to the SOA, we estimate that Vitol held inventories of VGO and crude oil feedstock (both delivered and in-transit) valued at approximately $582.1 million at the end of 2009 (as compared to $319.7 million at the end of 2008), which would have otherwise been assets of Harvest.

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.

SUMMARY OF FOURTH QUARTER RESULTS

	Three months ended December 31						
	2009			2008			
	Upstream	**Downstream**	**Total**	Upstream	Downstream	Total	Change
Revenues	**254,353**	**639,124**	**893,477**	238,550	690,152	928,702	(4%)
Royalties	**(40,338)**	**-**	**(40,338)**	(35,963)	-	(35,963)	12%
Net revenues	**214,015**	**639,124**	**853,139**	202,587	690,152	892,739	(4%)
Less:							
Purchased product for resale and processing	**-**	**579,107**	**579,107**	-	629,994	629,994	(8%)
Operating expenses	**61,693**	**62,848**	**124,541**	82,161	53,395	135,556	(8%)
Transportation and marketing	**3,142**	**2,291**	**5,433**	3,258	(5,805)	(2,547)	313%
Cash G&A	**9,825**	**441**	**10,266**	8,299	440	8,739	17%
Unit based compensation expense	**353**	**(213)**	**140**	(2,197)	(79)	(2,276)	106%
Total G&A	**10,178**	**228**	**10,406**	6,102	361	6,463	61%
Depreciation, depletion and accretion	**106,659**	**17,729**	**124,388**	119,339	20,638	139,977	(11%)
Net income per segment	**32,343**	**(23,079)**	**9,264**	(8,273)	(8,431)	(16,704)	155%
Realized gains (losses) on risk management contracts			**9,785**			24,434	(60%)
Unrealized gains (losses) on risk management contracts			**(10,639)**			192,252	(106%)
KNOC transaction costs			**(18,393)**			-	100%
Interest and other financing charges			**(28,828)**			(37,324)	(23%)
Currency exchange (loss) gain			**(4,177)**			(8,510)	(51%)
Large corporation tax and other tax			**(37)**			552	(107%)
Future income tax (expense) recovery			**30,003**			(76,060)	139%
Net income (loss)			**(13,022)**			78,640	(117%)
Per Trust Unit, basic			**(0.07)**			0.50	(114%)
Per Trust Unit, diluted			**(0.07)**			0.50	(114%)
Cash From Operating Activities			**76,999**			183,740	(58%)
Per Trust Unit, basic			**0.41**			1.18	(65%)
Per Trust Unit, diluted			**0.41**			1.10	(63%)
Distributions declared			**9,113**			140,646	(94%)
Distributions declared, per Trust Unit			**0.05**			0.90	(94%)
Distributions declared as a percentage of Cash From Operations			**12%**			77%	(65%)
UPSTREAM OPERATIONS							
Daily Production							
Light / medium oil (bbl/d)			**23,281**			25,088	(7%)
Heavy oil (bbl/d)			**9,491**			11,306	(16%)
Natural gas liquids (bbl/d)			**2,714**			2,770	(2%)
Natural gas (mcf/d)			**83,610**			96,079	(13%)
Total daily sales volume (boe/d)			**49,421**			55,177	(10%)
Operating Netback(1) ($/BOE)							
Revenue			**55.94**			46.99	19%
Royalties			**(8.87)**			(7.08)	25%
Operating expense			**(13.57)**			(16.19)	(16%)
Transportation expense			**(0.69)**			(0.64)	8%
Operating Netback(1)			**32.81**			23.08	42%
Cash capital expenditures			**31,720**			82,975	(62%)
DOWNSTREAM OPERATIONS							
Average daily throughput (bbl/d)			**75,814**			102,500	(26%)
Aggregate throughput (mbbl)			**6,974**			9,430	(26%)
Average Refining Margin (US$/bbl)			**6.55**			3.93	67%
Cash capital expenditures			**9,097**			24,317	(63%)

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

During the Fourth Quarter of 2009, cash from operating activities totaled $77.0 million, a $106.7 million decrease as compared to $183.7 million in the prior year. The decrease is primarily due to a $12.3 million increase in working capital as compared to an $89.0 million reduction in the prior year. Cash generated from our upstream operations of $134.1 million reflects an increase of $25.2 million from $108.9 million in the prior year, primarily due to a 42% increase in operating netbacks which were impacted by higher commodity prices and a 25% decrease in operating expenses. Cash generated from our downstream operations decreased to a $6.1 million deficiency during the Fourth Quarter of 2009, as compared to a $10.6 million cash improvement in the prior year, mainly due to a planned reduction in throughput to obtain more favorable economics as well as some unplanned downtime.

Upstream Operations

Our 2009 Fourth Quarter revenues increased $15.8 million compared to the same period in the prior year as a result of our realized commodity prices increasing by $8.95/boe (19%) in response to higher crude oil prices and partially offset by a 5,756 boe/d decrease in production volumes due to normal decline and a reduction in 2009 capital spending. Light/medium oil sales revenue for the three month period ended December 31, 2009 was $29.2 million (24%) higher than in same period in the prior year due to a favourable price variance of $37.9 million and an unfavourable volume variance of $8.7 million. Heavy oil revenues increased by $10.5 million (24%) due to a favourable price variance of $17.6 million and an unfavourable volume variance of $7.1 million. Natural gas sales revenue decreased by $24.8 million (40%) reflecting an unfavourable price variance of $16.8 million and an unfavourable volume variance of $8.0 million.

For the three months ended December 31, 2009, our net royalties as a percentage of revenue were 15.9% ($40.3 million) as compared to 15.1% ($36.0 million) in the same period in 2008. Our royalty rate for the Fourth Quarter of 2009 was higher than in the same period in 2008 due to favourable one-time credits recorded in December 2008.

Operating expenses decreased by $20.5 million (25%) for the three months ended December 31, 2009 as compared to the same period in the prior year, which reflects a $7.5 million decrease in power and fuel costs, comprised primarily of electric power, a $5.0 million decrease in repairs and maintenance costs and a $3.2 million decrease in well servicing costs. The average Alberta electric power price of $46.32/MWh in the Fourth Quarter of 2009 was 52% lower than the average price of $95.17/MWh in the same period in 2008.

Transportation and marketing expense was relatively consistent at $3.1 million for the three months ended December 31, 2009 and $3.3 million for the same period in 2008.

For the three months ended December 31, 2009, cash G&A increased by $1.5 million (17%) 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 2009 decreased to $31.7 million from $83.0 million in the same period in 2008. The decrease in spending is primarily due to decreased drilling activity as we drilled 19 wells (11.4 net) in the Fourth Quarter of 2009 as compared to drilling 82 wells (48.0 net) in the Fourth Quarter of 2008.

Downstream Operations

Our 2009 Fourth Quarter gross margin of $60.0 million was comparable to the 2008 Fourth Quarter gross margin of $60.2 million, as a result of higher refining margins that offset decreased throughput in the Fourth Quarter of 2009.

Refinery throughput averaged 75,814 bbl/d compared to 102,500 bbl/d in the prior year reflecting the impact of the planned crude and platformer units outage in the fall of 2009. While throughput decreased, our 2009 Fourth Quarter average refining margin increased to US$6.55/bbl from US$3.93/bbl in the same period of 2008 reflecting the recovery of crack spreads. As well, the average refining margin was impaired by a $35.3 million write-down on inventories in the Fourth Quarter of 2008 as a result of significant decreases in product prices.

The cost of feedstock was US$76.56/bbl in the Fourth Quarter of 2009, an increase of US$28.22/bbl compared to the same period in the prior year due to the significant quarter over quarter increase in WTI.

Operating costs averaged $3.43/bbl of throughput for the Fourth Quarter of 2009 as compared to $2.00/bbl in the same period in the prior year. The increase is due to decreased throughput in November and early December 2009 as a result of the planned crude and platformer units outage to conduct repairs and perform maintenance.

Capital spending decreased by $15.2 million to $9.1 million in the Fourth Quarter of 2009 as compared with the same period in the prior year due to spending $13.7 million to complete our visbreaker project in November 2008. Capital spending relating to the debottlenecking project in Fourth Quarter of 2009 was $4.1 million.

Corporate

Interest expense decreased by $8.5 million for the three months ended December 31, 2009 relative to the same period in the prior year. The decrease is primarily attributed to an $8.1 million decrease in interest expense on our bank borrowing due to lower interest rate, and a $0.7 million decrease in interest expense on our U.S. dollar Senior Notes due to the strengthening of the Canadian dollar over US dollar, partially offset by $0.3 million increase in our Convertible Debenture interest expense.

In the Fourth Quarter of 2009, we realized a $9.8 million gain and a $10.6 million unrealized loss on our risk management contracts as compared to a realized gain of $24.4 million and a $192.3 million unrealized gain in the same period in 2008. The realized gain and unrealized loss in the Fourth Quarter of 2009 is due the final settlement of our currency exchange contracts.

In the Fourth Quarter of 2009, we realized a $0.4 million gain on currency exchange transactions and an unrealized $4.5 million loss on currency translation, as compared to an $11.8 million realized loss and a $3.3 million unrealized gain in the same period in 2008. The realized gain in the Fourth Quarter of 2009 is primarily the result of the settling of our Senior Notes interest payable as the Canadian dollar strenghthened. The unrealized loss in the Fourth Quarter of 2009 relates to an increase in the net assets of our downstream operation on translation to Canadian dollars, offset by a decrease 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 2009 relative to the preceding seven quarters:

	2009				2008			
(000's except where noted)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Net Revenue	**$ 853,139**	**$ 991,854**	**$ 562,997**	**$ 731,095**	$ 892,739	$ 1,597,195	$ 1,622,079	$ 1,377,352
Net (Loss) Income	**$ (13,022)**	**$ (713,697)**	**$ (265,779)**	**$ 56,864**	$ 78,640	$ 295,788	$ (162,063)	$ (346)
Per Trust Unit, basic[1]	**$ (0.07)**	**$ (3.95)**	**$ (1.59)**	**$ 0.36**	$ 0.50	$ 1.93	$ (1.07)	$ -
Per Trust Unit, diluted[1]	**$ (0.07)**	**$ (3.95)**	**$ (1.59)**	**$ 0.36**	$ 0.50	$ 1.73	$ (1.07)	$ -
Cash from Operating Activities	**$ 76,999**	**$ 98,979**	**$ 75,879**	**$ 221,745**	$ 183,740	$ 133,493	$ 210,534	$ 128,119
Per Trust Unit, basic	**$ 0.41**	**$ 0.55**	**$ 0.45**	**$ 1.40**	$ 1.18	$ 0.87	$ 1.39	$ 0.85
Per Trust Unit, diluted	**$ 0.41**	**$ 0.55**	**$ 0.45**	**$ 1.28**	$ 1.10	$ 0.84	$ 1.26	$ 0.83
Distributions per Unit, declared	**$ 0.05**	**$ 0.15**	**$ 0.15**	**$ 0.65**	$ 0.90	$ 0.90	$ 0.90	$ 0.90
Total debt	**$ 1,525,006**	**$ 2,148,912**	**$ 2,216,452**	**$ 2,373,925**	$ 2,352,196	$ 2,284,664	$ 2,105,998	$ 2,209,451
Total assets	**$ 4,404,912**	**$ 4,423,802**	**$ 5,296,596**	**$ 5,785,269**	$ 5,745,407	$ 5,659,227	$ 5,637,879	$ 5,574,528

(1) The sum of the interim periods
(2) 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. Throughout the first three quarters of 2008, net revenues were the highest in Harvest's history due to strong commodity prices, however the significant decrease in commodity prices in the Fourth Quarter of 2008 and throughout 2009 coupled with the refinery turnaround in the Second Quarter of 2009 resulted in a significant decrease in net revenues.

Net (loss) 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, goodwill impairment and Trust Unit right compensation expense cause net (loss) income to vary significantly from period to period. In the Third Quarter of 2009, a goodwill impairment charge of $677.6 million relating to the Upstream reporting unit was recognized, while in the Second Quarter of 2009, a goodwill impairment charge of $206.5 million relating to the Downstream reporting unit was recognized. Changes in the fair value of our risk management contracts have also contributed to the volatility in net (loss) income over the preceding eight quarters. For these reasons, our net (loss) income does not reflect the same trends as net revenues or cash from operating activities, nor is it expected to.

Cash from operating activities is closely aligned with the trend in commodity prices for our Upstream operations and reflects the cyclical nature of the Downstream segment. It is also significantly impacted by changes in working capital. In the First Quarter of 2009, cash from operating activities increased from the previous quarter mainly reflecting increased refining margins. The decrease in the Second Quarter of 2009 and the subsequent recovery in the Third Quarter mainly reflect the reduction in product sales from the Downstream segment due to the completion of a planned turnaround. The Fourth Quarter of 2009 decreased due to a planned reduction in refinery throughput to increase gasoline and distillate yields and minimize HSFO production to obtain more favorable economics as well as some unplanned downtime associated with maintenance work on the crude and platformer units.

Total debt has remained relatively stable until the Fourth Quarter of 2009, reflecting moderate acquisition activity, offset by the issuance of Trust Units in the Second Quarter of 2009, and a net surplus of cash from operating activities over distributions to Unitholders. The decrease in the Fourth Quarter of 2009 reflects the approximate $600 million repayment of bank indebtedness concurrent with the closing of the Arrangement Agreement with Korea National Oil Corporation on December 22, 2009.

Total assets have also remained relatively stable until the Second Quarter of 2009. The stability reflects moderate acquisition activity offset by a reduction in net book value associated with depletion and depreciation charges. In the Second Quarter of 2009, total assets decreased due to recording an impairment charge associated with the Downstream reporting unit's goodwill, and then in the Third Quarter of 2009, a further decrease in total assets occurred resulting from a further impairment charge associated with the Upstream reporting unit's goodwill.

OUTLOOK

During 2009, we saw a dramatic repositioning of Harvest with the year-end acquisition of Harvest units by KNOC. Concurrent with the acquisition of the outstanding units, Harvest issued an incremental $600 million of shares to KNOC that allowed bank debt to be reduced by the same amount. In early 2010, we issued an incremental $466 million of equity to KNOC further reducing bank debt in advance of the required change-of-control offers to holders of the senior notes and convertible debentures. With the improved balance sheet and the elimination of the distribution on the equity as well as an attractive asset base with identified growth opportunity, Harvest is well-positioned as a growth-oriented integrated oil company in Canada.

Currently the economic environment is mixed for Harvest with relatively strong crude oil and natural gas liquids prices offset by weaker natural gas prices and refining margins. We anticipate that we will continue to see a volatile commodity price environment in 2010. In light of the attractive investment opportunities in the asset base and the improved balance sheet situation, we have increased our capital expenditures expectations for 2010 in both the upstream and downstream business.

For our upstream operations, our capital spending plan for 2010 has been set at $320 million with a focus on oil projects. We expect to have an active drilling program with approximately 190 wells to be drilled over the course of the year. We also plan to continue with EOR projects in our larger oil reservoirs at Hay River, Bellshill Lake, Wainwright and Suffield with planned spending of $26 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 an increased level of drilling activity will likely result in increasing production volumes through the year.

We anticipate that our upstream production will average approximately 36,000 bbls/d of liquids and 80,000 mcf/d of natural gas (approximately 50,000 boe/d). Light and medium gravity oil, including natural gas liquids, is expected to represent approximately 55% of our total production in 2010 with heavy oil and natural gas accounting for 18% and 27%, 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 2010, we are projecting our operating costs to be approximately $14.00 per boe and general and administrative costs to be approximately $1.80 per boe.

In our downstream operations, capital spending will be directed to maintenance activities and increased discretionary profit improvement investments to improve reliability, increase throughput, enhance margins and reduce operating costs. We currently anticipate spending approximately $150 million on capital projects, including $78 million for the Debottleneck Projects. The Debottleneck Projects are a suite of investments estimated to cost a total of $310 million over the course of 2010 and 2011. An additional $60 million will be spent in 2010 on catalyst and turnaround costs.

We experienced a production upset due to a fire in the hydrocracking unit and consequential shutdown of the refinery on January 7, 2010 and we are currently planning to operate at near capacity subsequent to restoration of the operation of all units, which is expected by the end of March. Therefore, full year throughput is projected to average 90,000 bpd of feedstock with a refined product yield of 45% distillates, 30% gasoline and 25% HSFO. We also project that operating costs and purchased energy costs will aggregate to $6.19 per bbl. The cash flow contribution from our marketing activities in the Province of Newfoundland and Labrador is expected to contribute approximately $27 million of incremental cash flow to the downstream operations.

At the beginning of 2010, we had $914 million principal amount of Convertible Debentures issued in five series with a weighted average interest rate of approximately 7.1%. The terms of our Convertible Debentures require semi-annual payments of interest.

During 2010, we will be negotiating a new bank credit facility. At year-end 2009, we had about $428 million drawn against a $600 million facility that matures in April 2010. After a further $466 million equity issue in January and before the results from the offers made to holders of senior debt and convertible debentures, we had no drawings against the committed bank facility.

Overall, we expect that based on current commodity price expectations, our 2010 cash from operating activities will be similar to that experienced in 2009. With distributions to Unitholders eliminated, we will increase capital expenditures to take advantage of identified opportunities in the asset base. The following table reflects the sensitivity of our 2010 operations to changes in the following key factors to our business:

	Assumption	Change	Annual Impact on Cash Flow ($ millions)
WTI oil price (US$/bbl)	$ 75.00	$ 5.00	$ 42.7
CAD/USD exchange rate	$ 0.95	$ 0.05	$ 45.7
AECO daily natural gas price	$ 5.00	$ 1.00	$ 25.8
Refinery crack spread (US$/bbl)	$ 8.00	$ 1.00	$ 32.9
Upstream Operating Expenses (per boe)	$ 14.00	$ 1.00	$ 21.5

In our upstream business, we will continue to evaluate opportunities to acquire producing oil and/or natural gas properties as well as offer selected properties for divestment to maintain and enhance our productive capability.

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 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.

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 2009 (2008 - 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 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 and early adoption allowed. 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. Harvest is currently assessing the impact of this standard on our financial position and future results.

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 Standards ("IFRS") commencing January 1, 2011 which will require comparative IFRS information for the 2010 year end.

In July 2009, the International Accounting Standards Board ("IASB") issued an amendment with additional exemptions 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.

We have staffed a project team with regular reporting to our senior management team and to the Audit Committee of the Board of Directors to ensure that we meet the IFRS transition requirements for 2011. The IFRS project team has developed an IFRS Transition Plan that consists of four key phases:

1. Diagnostic phase – an initial assessment of the differences between Canadian accounting standards and IFRS, Planning, Assessment, Implementation and Training.
2. Planning phase – development of a project plan that includes assignment of roles and responsibilities, timeline and budget.
3. Assessment phase – a detailed comparison of the IFRS and Canadian standards to identify all applicable differences, as well as exemptions for first time adopters and expected changes to the relative IFRS standards. An assessment is then done on the impact on our accounting policies; information technology and data systems; business processes and data requirements; internal control over financial reporting, disclosure controls and procedures; financial reporting expertise and business activities that may be influenced such as debt covenants, capital requirements and compensation arrangements.
4. Implementation phase – preparing transitional opening IFRS financial statements; implementing accounting policy changes; implementing and testing data, process, system and control changes; training.

We are currently involved in the assessment phase of the project. We have completed the detailed analysis of the differences for most elements of our financial statements and are currently working with representatives from the various operational areas to select accounting policies and assess the impact of the differences on the data requirements, business processes, financial systems and internal controls. We have commenced our training of key employees through this process as well. Korea is on the same IFRS conversion schedule as Canada and as a result we must reassess the accounting policies that we have initially selected to ensure that they align with KNOC's policy choices. At this stage in the project, the full impact of adopting IFRS on Harvest's financial position and future results can not be determined; however, the most significantly impacted areas to date are property, plant and equipment and impairment of assets.

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. We intend to continue executing our business plan to create value.

We have segregated the identification of business risks into those generally applicable to upstream operations as well as downstream operations and should be read in conjunction with the full description of these risks in our Annual Information Form for the year ended December 31, 2009 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.
- 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 severe 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.
- Variations in interest rates on our current and/or future financing arrangements may result in significant increases in our borrowing costs.
- Our crude oil sales and refining margins are denominated in US dollars while we incur costs in Canadian dollars which results in a currency exchange exposure.

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.

On March 3, 2009, the Government of Alberta announced a new three-point stimulus plan, and extended the plan to two years on June 25, 2009. The drilling royalty credit for new conventional oil and natural gas wells is a two-year program effective for wells spud on or after April 1, 2009, and 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. The royalty rate cap is also effective April 1, 2009 for new conventional oil and natural gas wells and 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, 2011. The third point is an abandonment and reclamation fund which will provide $30 million to be invested by the Orphan Well Association to abandon and reclaim old well sites where there is no legally responsible or financially able party available.

In the February 2009 Speech from the Throne, the Alberta Government announced they were initiating a competitiveness review of the provinces Oil and Gas Sector which may include revisions to the current royalty program. The review is expected to be completed in 2010. 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, 2009 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, 2009 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, 2009, 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, 2009. 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, 2009, the design and operation of internal controls were effective.

During the year ended December 31, 2009, 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.

CONSOLIDATED BALANCE SHEETS

As at December 31
(thousands of Canadian dollars)

		2009		2008
Assets				
Current assets				
Accounts receivable and other	$	**180,839**	$	173,341
Fair value of risk management contracts *[Note 20]*		**-**		36,087
Prepaid expenses and deposits		**15,551**		11,843
Inventories *[Note 5]*		**81,784**		55,788
		278,174		277,059
Property, plant and equipment *[Note 6]*		**3,974,070**		4,468,505
Intangible assets *[Note 8]*		**87,846**		106,002
Future income tax *[Note 18]*		**64,822**		-
Goodwill *[Note 7]*		**-**		893,841
	$	**4,404,912**	$	5,745,407
Liabilities and Unitholders' Equity				
Current liabilities				
Bank loan *[Note 11]*	$	**428,017**	$	-
Accounts payable and accrued liabilities *[Note 9]*		**216,563**		221,418
Cash distribution payable		**-**		47,160
Current portion of convertible debentures *[Note 13]*		**172,053**		2,513
Current portion of $7^{7/8}$% Senior notes *[Note 12]*		**41,909**		
Fair value deficiency of risk management contracts *[Note 20]*		**2,052**		235
		860,594		271,326
Bank loan *[Note 11]*		**-**		1,226,228
$7^{7/8}$% Senior notes *[Note 12]*		**217,210**		298,210
Convertible debentures *[Note 13]*		**665,817**		825,246
Asset retirement obligation *[Note 10]*		**284,043**		265,997
Employee future benefits *[Note 19]*		**9,394**		10,551
Deferred credit		**359**		522
Future income tax *[Note 18]*		**-**		203,998
Unitholders' equity				
Unitholders' capital *[Note 14]*		**4,669,559**		3,897,653
Equity component of convertible debentures		**-**		84,100
Contributed surplus *[Note 15]*		**315,255**		6,433
Accumulated income		**(476,750)**		458,884
Accumulated distributions		**(2,056,444)**		(1,891,674)
Accumulated other comprehensive income (loss)		**(84,125)**		87,933
		2,367,495		2,643,329
	$	**4,404,912**	$	5,745,407

Commitments and contingencies *[Note 22]*
Subsequent events *[Note 23]*
See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

For the Years Ended December 31
(thousands of Canadian dollars, except per Trust Unit amounts)

		2009		2008
Revenue				
Petroleum, natural gas, and refined product sales	**$**	**3,267,945**	$	5,737,809
Royalty expense		**(128,860)**		(248,445)
		3,139,085		5,489,364
Expenses				
Purchased products for processing and resale		**2,015,671**		3,850,507
Operating		**500,586**		537,149
Transportation and marketing		**26,237**		34,243
General and administrative *[Note 17]*		**38,045**		34,743
Korea National Oil Corporation acquisition related costs [Note 1 and 17]		**18,393**		-
Realized net (gains) losses on risk management contracts		**(62,803)**		200,782
Unrealized net losses (gains) on risk management contracts		**37,904**		(185,921)
Interest and other financing charges on short term debt, net		**8,896**		295
Interest and other financing charges on long term debt		**110,943**		146,375
Depletion, depreciation, amortization and accretion		**527,579**		519,811
Goodwill impairment *[Note 7]*		**884,077**		-
Currency exchange (gain) loss		**(2,265)**		30,882
Large corporations tax and other tax		**(509)**		(81)
Future income tax expense (recovery) *[Note 18]*		**(28,035)**		108,560
		4,074,719		5,277,345
Net income (loss) for the year		**(935,634)**		212,019
Other comprehensive income (loss)				
Cumulative translation adjustment		**(172,058)**		284,692
Comprehensive income (loss) for the year	$	**(1,107,692)**	$	496,711
Net income (loss) per Trust Unit, basic *[Note 14]*	**$**	**(5.38)**	$	1.39
Net income (loss) per Trust Unit, diluted *[Note 14]*	**$**	**(5.38)**	$	1.39

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY

As at 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, 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)	-	-	-	-
Settlement of convertible debentures						
10.5% Debentures Due 2008	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**
Issued for cash						
June 4, 2009	126,509					
December 22, 2009	600,000					
Issued for corporate acquisition [Note 4a]	4,618					
Settlement of convertible debentures						
9% Debentures Due 2009	944	-	-	-	-	-
8% Debentures Due 2009	1,588	(11)	11	-	-	-
Elimination of equity component of convertible debentures resulting from the acquisition by Korea National Oil Corporation [Note 13]	-	(84,089)	84,089	-	-	-
Exercise of unit appreciation rights and other	397	-	-	-	-	-
Issue costs, net of tax	(5,867)	-	-	-	-	-
Currency translation adjustment	-	-	-	-	-	(172,058)
Net loss	-	-	-	(935,634)	-	-
Distributions and distribution reinvestment plan	43,717	-	-	-	(164,770)	-
Future income tax adjustment from change in shareholder status [Note 18]	-	-	224,722	-	-	-
At December 31, 2009	**$4,669,559**	**$ -**	**$ 315,255**	**$ (476,750)**	**$ (2,056,444)**	**$ (84,125)**

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31
(thousands of Canadian dollars)

	2009	2008
Cash provided by (used in)		
Operating Activities		
Net income (loss) for the year	$ (935,634)	$ 212,019
Items not requiring cash		
Depletion, depreciation, amortization and accretion	527,579	519,811
Impairment of goodwill *[Note 7]*	884,077	-
Unrealized currency exchange (gain) loss	(5,337)	11,736
Non-cash interest expense and amortization of finance charges	15,521	14,197
Unrealized loss (gain) on risk management contracts *[Note 20]*	37,904	(185,921)
Future income tax expense (recovery)	(28,035)	108,560
Unit based compensation recovery	(5,212)	(1,577)
Employee benefit obligation	(1,157)	(1,618)
Other non-cash items	58	(5)
Settlement of asset retirement obligations *[Note 10]*	(14,270)	(11,418)
Change in non-cash working capital	(1,892)	(9,897)
	473,602	655,887
Financing Activities		
Issue of Trust Units, net of issue costs	719,504	-
Issue of convertible debentures, net of issue costs *[Note 13]*	-	239,498
Bank repayments *[Note 11]*	(810,704)	(52,413)
Financing costs	(3,300)	(228)
Cash distributions	(121,053)	(410,678)
Change in non-cash working capital	(47,893)	4,098
	(263,446)	(219,723)
Investing Activities		
Additions to property, plant and equipment	(230,151)	(327,474)
Business acquisitions	-	(36,756)
Property acquisitions	(2,635)	(138,493)
Property dispositions	64,751	46,476
Change in non-cash working capital	(41,583)	24,274
	(209,618)	(431,973)
Change in cash and cash equivalents	538	4,191
Effect of exchange rate changes on cash	(538)	(4,191)
Cash and cash equivalents, beginning of year	-	-
Cash and cash equivalents, end of year	$ -	$ -
Interest paid	$ 87,765	$ 115,209
Large corporation tax and other tax (received) paid, net	$ (509)	$ (81)

See accompanying notes to these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2009 and 2008

(tabular amounts in thousands of Canadian dollars, except Trust Unit, and per Trust Unit amounts)

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 and is governed pursuant to the Amended and Restated Trust Indenture dated December 22, 2009 between Harvest Operations Corp. ("Harvest Operations"), a wholly owned subsidiary and manager of the Trust, and 1496965 Alberta Ltd. as Trustee (the "Trust Indenture"). The beneficiary of the Trust is the holder of its Trust Units (the "Unitholder"). On December 22, 2009, Korea National Oil Corporation Canada Ltd. ("KNOC"), a wholly owned subsidiary of subsidiary Korea National Oil Corporation, purchased all of the issued and outstanding Trust Units of the Trust.

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 77/8% 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 interest 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").

(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, income taxes 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.

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.

(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.

Intangible assets with determinable useful lives are amortized using the straight line method over the estimated lives of the assets, which range from 5 to 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.

(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

Harvest follows the asset and 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.

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 the Trust and its trust subsidiaries distribute all of their taxable income to their Unitholders, neither the Trust nor its trust subsidiaries are currently subject to income tax. In 2007 the Canadian government enacted legislation to apply a tax to distributions from Canadian publicly traded income trusts; however, with the purchase of Harvest by the KNOC on December 22, 2009, Harvest is no longer a publicly traded trust and as a result is no longer subject to a distribution tax beginning in 2011. Therefore, as long as Harvest maintains its current structure and the Trust and its trust subsidiaries continue to distribute all of their taxable income, Harvest and its trust subsidiaries will not be subject to tax.

(j) Unit-based Compensation

Prior to the acquisition by KNOC, Harvest had a Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan. The compensation expense for these plans was determined 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 vested, further changes in the intrinsic value were 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 was used as participants in the plan had 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 had the option upon exercise to receive a cash payment or Trust Unit equivalent, equal to the value of awards outstanding, which was 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 plan provides 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.

(n) Financial Instruments

Harvest classifies cash and price risk management contracts as held-for-trading and measures these instruments at fair value each reporting period. The remainder of Harvest's financial instruments are measured at amortized cost.

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.

3. New Accounting Policies

(a) Current Year Accounting Changes

Financial Instruments - Disclosures

Effective December 31, 2009, Harvest adopted CICA issued amendments to Handbook Section 3862, Financial Instruments – Disclosures. The amendments include enhanced disclosures relating to the fair value of financial instruments and the liquidity risk associated with financial instruments. Section 3862 now requires that all financial instruments measured at fair value be categorized into one of three hierarchy levels. Refer to Note 20 Financial Instruments and Risk Management for enhanced fair value disclosures and liquidity risk disclosures.

Goodwill and Intangibles

Effective January 1, 2009, Harvest adopted the new Canadian Institute of Chartered Accountants ("CICA") accounting standard "Goodwill and Intangible Assets", Section 3064 which replaced Section 3062 "Goodwill and Other Intangible Assets" and Section 3450, "Research and Development Costs". Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of intangible assets and goodwill subsequent to its initial recognition. The adoption of this standard had no impact on the consolidated financial statements.

(b) Future Accounting Changes

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

The CICA Handbook Section 1582 ''Business Combinations'' is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting the standard is expected to have a material effect on the way the Company accounts for future business combinations. Entities adopting Section 1582 will also be required to adopt CICA Handbook Sections 1601 ''Consolidated Financial Statements'' and 1602 ''Non-Controlling Interests''. These standards will require non-controlling interests to be presented as part of Shareholders' Equity on the balance sheet. In addition, the income statement of the controlling parent will include 100 per cent of the subsidiary's results and present the allocation between the controlling and non-controlling interests. These standards will be effective January 1, 2011, with early adoption permitted. The changes resulting from adopting Section 1582 will be applied prospectively and the changes from adopting Sections 1601 and 1602 will be applied retrospectively. Harvest is currently assessing the impact of this standard on our financial position and future results.

International Financial Reporting Standards ("IFRS")

In February 2008, the CICA Accounting Standards Board ("ASB") announced that Canadian public reporting issuers will be required to report under International Financial Reporting Standards ("IFRS") commencing January 1, 2011 which will require comparative IFRS information for the 2010 year end. We will begin reporting under IFRS as of January 1, 2011, but given the current stage of the Company's IFRS project the full impact of adopting IFRS on Harvest's financial position and future results can not be determined.

4. Acquisitions

(a) Pegasus Oil & Gas Inc. ("Pegasus")

On August 11, 2009, Harvest acquired approximately 93.5% of the issued and outstanding class A shares of Pegasus in exchange for 0.015 units of Harvest for each Pegasus Class A Share and approximately 90.6% of the issued and outstanding class B shares of Pegasus in exchange for 0.15 units of Harvest for each Pegasus Class B Share for total consideration of approximately $4.6 million plus the assumption of $13.9 million of debt. This amount consisted of the issuance of 670,288 Trust Units at an ascribed price of $6.89 per Trust Unit, based on the weighted average trading price of the Harvest Trust Units before and after the announcement date of June 15, 2009. The results of operations of this acquisition have been included in the consolidated financial statements since its acquisition date.

(b) 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.

(c) 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.

5. Inventories

		December 31, 2009		December 31, 2008
Petroleum products				
Upstream – pipeline fill	**$**	**1,183**	$	603
Downstream		**76,424**		50,311
		77,607		50,914
Parts and supplies		**4,177**		4,874
Total inventories	**$**	**81,784**	$	55,788

During the year ended December 31, 2009, Harvest recognized $2.4 million (2008 – $35.3 million) of inventory impairments and $9.7 million (2008 – nil) of recoveries of inventory impairments in its downstream operations. At December 31, 2009, inventories held at net realizable value totaled $24.5 million (December 31, 2008 – $37.6 million).

6. Property, Plant and Equipment

	December 31, 2009			December 31, 2008		
	Upstream	**Downstream**	**Total**	Upstream	Downstream	Total
Cost	**$ 4,848,984**	**$ 1,328,727**	**$ 6,177,711**	$ 4,710,725	$ 1,493,039	$ 6,203,764
Accumulated depletion and depreciation	**(1,998,004)**	**(205,637)**	**(2,203,641)**	(1,572,449)	(162,810)	(1,735,259)
Net book value	**$ 2,850,980**	**$ 1,123,090**	**$ 3,974,070**	$ 3,138,276	$ 1,330,229	$ 4,468,505

General and administrative costs of $10.9 million (2008 – $10.0 million) have been capitalized during the year ended December 31, 2009, of which $2.5 million (2008 - nil) 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, 2009 including future development costs of $446.8 million (2008 – $489.5 million). Downstream major parts inventory of $6.6 million were excluded from the asset base subject to depreciation at December 31, 2009 (2008 - $7.5 million). Downstream assets under construction of $30.3 million were excluded from the asset base subject to depreciation at December 31, 2009 (2008 - $12.7 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 exceeded the carrying amount of its petroleum and natural gas assets as at December 31, 2009 and 2008, 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, 2009 were as follows:

Year	WTI Oil[(1)] (US$/barrel)	Currency Exchange Rate	Edmonton Light Crude Oil[(1)] (CDN$ barrel)	AECO Gas[(1)] (CDN$/MMBtu)
2010	80.00	0.95	83.20	6.05
2011	83.60	0.95	87.00	6.75
2012	87.40	0.95	91.00	7.15
2013	91.30	0.95	95.00	7.45
2014	95.30	0.95	99.20	7.80
Thereafter (escalation)	2%	0%	2%	2%

(1) Actual prices used in the impairment test were adjusted for commodity price differentials specific to Harvest.

7. Goodwill Impairment

At June 30, 2009, it was determined that an impairment test of the Downstream reporting unit was required due to expectations of lower future refining margins and the probable deferral of certain future capital expenditures. Harvest completed the two-step process to determine whether the goodwill of the Downstream reporting unit was impaired. The first step of the impairment test involved comparing the fair value of the reporting unit to the carrying value, including goodwill. The fair value was determined using a discounted cash flow approach which incorporated management's expectations of future throughput and expenses and the forward curve for refined product crack spreads. The fair value of the Downstream reporting unit was below the carrying value, indicating a potential impairment. The second step required the fair value of goodwill be determined by valuing the reporting unit's net assets in the same manner as allocating a purchase price in a business combination. It was determined that the goodwill associated with the Downstream reporting unit was fully impaired and a pre-tax charge of $206.5 million was recorded in the financial results at June 30, 2009.

At September 30, 2009, it was determined that the fair value of the Trust, based on the Arrangement Agreement with the KNOC, indicated a potential impairment of the Upstream goodwill. An impairment test for the Upstream reporting unit was conducted and the fair value of the reporting unit was below its carrying value as at September 30, 2009. The fair value of the Upstream goodwill was determined by valuing the reporting unit's net assets in the same manner as allocating a purchase price in a business combination. It was determined that the goodwill associated with the Upstream reporting unit was fully impaired and a pre-tax charge of $677.6 million was recorded at September 30, 2009.

Refer to the goodwill table in Note 21 for the change in goodwill during the year ended December 31, 2009.

8. Intangible Assets

	December 31, 2009			December 31, 2008		
	Cost	**Accumulated Amortization**	**Net book value**	Cost	Accumulated Amortization	Net book value
Engineering drawings	**$ 93,539**	**$ (15,005)**	**$ 78,534**	$ 108,402	$ (11,969)	$ 96,433
Marketing contracts	**6,505**	**(2,967)**	**3,538**	7,539	(2,480)	5,059
Customer lists	**3,938**	**(1,264)**	**2,674**	4,564	(1,008)	3,556
Fair value of office lease	**931**	**(875)**	**56**	931	(652)	279
Financing costs	**3,300**	**(256)**	**3,044**	7,300	(6,625)	675
Total	**$ 108,213**	**$ (20,367)**	**$ 87,846**	$ 128,736	$ (22,734)	$ 106,002

9. Accounts Payable and Accrued Liabilities

	December 31, 2009	December 31, 2008
Trade accounts payable	**$ 71,309**	$ 62,771
Accrued interest	**16,530**	17,262
Trust Unit Rights Incentive Plan and Unit Award Incentive Plan *[Note 17]*	**-**	3,894
Other accrued liabilities	**117,539**	126,170
Current portion of asset retirement obligation	**11,185**	11,321
Total	**$ 216,563**	$ 221,418

10. 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 $1,202 million which will be incurred between 2010 and 2059. 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, 2009	December 31, 2008
Balance, beginning of year	$ 277,318	$ 213,529
Incurred on business acquisition of a private corporation	1,411	1,900
Liabilities incurred	1,351	4,371
Revision of estimates	7,219	49,395
Net liabilities acquired (settled) through acquisition (disposition)	(2,538)	910
Liabilities settled	(14,270)	(11,418)
Accretion expense	24,737	18,631
Balance, end of year(1)	**$ 295,228**	**$ 277,318**

(1) Current portion of the asset retirement obligation is included in accounts payable and accrued liabilities [Note 9]

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.

11. Bank Loan

Harvest had a $1.6 billion three year syndicated credit facility with a maturity date of April 30, 2010. With the purchase of Harvest by KNOC on December 22, 2009, the facility was renegotiated and reduced to $600 million concurrent with a $600 million payment made in December. The maturity date remains unchanged at April 30, 2010. At December 31, 2009, Harvest had $428.0 million drawn from the $600 million available under the Credit Facility ($1,226.2 million drawn from the $1.6 billion available at December 31, 2008).

The Credit Facility is secured by 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 77/8% 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 77/8% Senior Notes described in Note 12, availability is subject to the following quarterly financial covenants:

	Covenant	As at December 31, 2009
Secured debt to EBITDA	3.0 to 1.0 or less	0.7
Total debt to EBITDA	3.5 to 1.0 or less	2.7
Secured debt to Capitalization	50% or less	11%
Total debt to Capitalization	55% or less	40%

For the year ended December 31, 2009, Harvest's average interest rate on advances under the Credit Facility was 1.44% (2008 – 4.12%).

12. 77/8% Senior Notes

On October 14, 2004, Harvest Operations Corp., a wholly owned subsidiary of Harvest, issued US$250 million of 77/8% Senior Notes for cash proceeds of $311,951,000. The 77/8% 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, 2009 at 101.969% of the principal amount
- After October 15, 2010 at 100% of the principal amount

The 77/8% Senior Notes contains a change of control covenant that requires Harvest Operations Corp. to commence an offer to repurchase the 77/8% 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. On December 22, 2009, concurrent with the acquisition of 100% of Harvest's outstanding Trust Units by Korea National Oil Company, the change of control covenant was triggered and on January 20, 2010 Harvest Operations Corp. delivered formal notice to the trustee under the indenture of its offer to purchase all outstanding 77/8% Senior Notes; refer to Note 23 for details on the redemptions. 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 77/8% 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, 2009, the Borrowing Base Covenant restricts secured indebtedness to Cdn$1.87 billion (at December 31, 2008 - Cdn$1.91 billion).

In addition, the covenants of the 77/8% 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 77/8% 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, 2009, amounted to a carry-forward of approximately Cdn$2.2 billion (Cdn$1.5 billion as at December 31, 2008).

The fair value of the 77/8% Senior Notes at December 31, 2009 was $265.4 million (2008 - $231.4 million).

13. Convertible Debentures

Harvest has five 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.

KNOC's acquisition of all the outstanding Trust Units constitutes a change of control under the debenture indenture whereby Harvest is required to make an offer to the holders of the debentures to repurchase the debentures for cash consideration equal to 101% of the principal amount plus any accrued and unpaid interest within 30 days; refer to Note 23 for details on the redemptions.

As a result of KNOC acquiring all of the outstanding Trust Units of Harvest and will be settled with cash upon maturity, the debentures are no longer convertible into Units but investors would receive $10.00 for each unit notionally received based on each series conversion rate. Because every series of debentures carry a conversion price that exceeds $10.00 per unit, it is assumed that no investor would exercise their conversion option.

The debentures may be redeemed by Harvest at its option in whole or in part prior to their respective redemption dates. The redemption price for the first redemption period is at a price equal to $1,050 per debenture and at $1,025 per debenture during the second redemption period. Any redemption will include accrued and unpaid interest at such time.

The following is a summary of the five series of convertible debentures:

Series	Conversion price / Trust Unit	Maturity	First redemption period	Second redemption period
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, 2009			December 31, 2008		
	Face Value	**Carrying Amount**	**Fair Value**	Face Value	Carrying Amount(1)	Fair Value
9% Debentures Due 2009	**$ -**	**$ -**	**$ -**	$ 944	$ 940	$ 984
8% Debentures Due 2009	**-**	**-**	**-**	1,588	1,573	1,540
6.5% Debentures Due 2010	**37,062**	**36,187**	**37,562**	37,062	35,387	29,650
6.40% Debentures Due 2012	**174,626**	**170,667**	**176,460**	174,626	169,455	75,089
7.25% Debentures Due 2013	**379,256**	**362,216**	**385,703**	379,256	358,533	166,835
7.25% Debentures Due 2014	**73,222**	**68,458**	**74,467**	73,222	67,549	36,611
7.5% Debentures Due 2015	**250,000**	**200,342**	**256,875**	250,000	194,322	107,500
	$ 914,166	**$ 837,870**	**$ 931,067**	$ 916,698	$ 827,759	$ 418,209

(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.

On May 31, 2009, the 9% Debenture matured and Harvest elected to settle its obligation by issuing 136,906 Trust Units rather than settling in cash.

On September 30, 2009, the 8% Debenture matured and Harvest elected to settle its obligation by issuing 259,184 Trust Units rather than settling in cash.

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	
	2009	2008
Outstanding, beginning of year	**157,200,701**	148,291,170
Issued for cash		
June 4, 2009 at $7.30 per Trust Unit	**17,330,000**	-
December 22, 2009 at $10.00 per Trust Unit	**60,000,000**	-
Issued for corporate acquisition	**670,288**	-
Convertible debenture conversions		
9% Debentures Due 2009	**-**	2,310
8% Debentures Due 2009	**-**	8,710
10.5% Debentures Due 2008	**-**	344
Settlement of convertible debentures		
10.5% Debentures Due 2008	**-**	1,166,593
9% Debentures Due 2009	**136,906**	-
8% Debentures Due 2009	**259,184**	-
Distribution reinvestment plan issuance	**6,590,755**	7,655,414
Exercise of unit appreciation rights and other	**80,967**	76,160
Outstanding, end of year	**242,268,801**	157,200,701

In 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. With the acquisition of all the issued and outstanding Trust Units of Harvest by KNOC on December 22, 2009, the distribution reinvestment plan was cancelled.

(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, 2009**		December 31, 2008
Net (loss) income, basic	**$**	**(935,634)**	$	212,019
Interest on Convertible Debentures		-		95
Net income, diluted[(1)(3)]	**$**	**(935,634)**	$	212,114

Weighted average Trust Units adjustments	**December 31, 2009**	December 31, 2008
Number of Units		
Weighted average Trust Units outstanding, basic	**173,785,806**	152,836,717
Effect of Convertible Debentures	**-**	69,155
Effect of Employee Unit Incentive Plans	**-**	200,789
Weighted average Trust Units outstanding, diluted[(2)(3)]	**173,785,806**	153,106,661

(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, 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 and nil for the Employee Unit Incentive Plans, as the impact would be anti-dilutive.

(3) As a result of the acquisition of all the issued and outstanding Trust Units of Harvest by Korea National Oil Company on December 22, 2009, the debentures are no longer convertible into Trust Units at the option of the holder and the Employee Unit Incentive Plans have been settled; therefore, no adjustment for the effect of Convertible Debentures or the effect of Employee Unit Incentive Plans have been included in the determination of net income, diluted or weighted average Trust Units outstanding, diluted for the year ended December 31, 2009.

15. Contributed Surplus

	December 31, 2009	December 31, 2008
Balance, beginning of year	**$ 6,433**	$ -
Settlement of convertible debentures	**11**	6,433
Elimination of equity component of convertible debentures resulting from the acquisition by KNOC	**84,089**	-
Future income tax adjustment from change in shareholder status [Note 18]	**224,722**	-
Balance, end of year	**$315,255**	$ 6,433

16. Capital Structure

Harvest considers its capital structure to comprise its credit facilities, 77/8% Senior Notes, Convertible Debentures and unitholders' equity.

	December 31, 2009	December 31, 2008
Bank debt	**$ 428,017**	$ 1,226,228
$7^{7/8}$% Senior Notes (1)	**262,750**	304,500
Principal amount of convertible debentures	**914,166**	916,698
Total Debt	**1,604,933**	2,447,426
Unitholders' equity (2)	**4,669,559**	2,559,229
Total capitalization	**$ 6,274,492**	$ 5,006,655

(1) Face value converted at the year end exchange rate.
(2) Less equity component of convertible debentures at December 31, 2008.

Harvest's primary objective in its management of capital resources is to have access to capital to fund its financial obligations as well as future growth. Harvest monitors its capital structure and makes adjustments according to market conditions to remain flexible while meeting these objectives. Accordingly, Harvest may adjust its capital spending programs, issue new units in exchange for equity capital from the unitholder, issue new debt or repay existing debt.

Harvest evaluates its capital structure using the following non-GAAP financial ratios: bank debt to Twelve Month Trailing 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. These ratios are also included in our externally imposed capital requirements per our credit facility [Note 10], Senior Notes [Note 11] and Convertible Debentures [Note 12]; Harvest was in compliance with all debt covenants at December 31, 2009.

At December 31, 2008 the issuance of Trust Units was limited by the "normal growth guidelines" contained in Bill C-52 issued by the Government of Canada; however, subsequent to the acquisition of all the outstanding Trust Units by KNOC, Harvest is no longer subject to this legislation as it is no longer a publicly traded trust. Harvest's Trust Unit indenture provides for the issuance of an unlimited number of Trust Units.

17. Employee Unit Incentive Plans

Harvest had a Trust Unit Rights Incentive Plan and Unit Award Incentive Plan ("Unit Award Plan") in place prior to the KNOC acquisition.

Trust Unit Rights Incentive Plan

Harvest was authorized to grant non-transferable unit appreciation rights to directors, officers, consultants, employees and other service providers. The initial exercise price of rights granted under the plan was equal to the market price of the Trust Units at the time of grant and the maximum term of each right was five years. The rights vest equally over four years commencing on the first anniversary of the grant date. Any portion of a distribution that did not reduce the exercise price on exercised rights was paid to the holder in a lump sum cash payment after the rights had been exercised.

Upon the exercise of unit appreciation rights the holder had the sole discretion to elect to receive cash or units. As a result, Harvest recognized a liability on its consolidated balance sheet associated with the rights reserved under the plan. This obligation represented the difference between the market value of the Trust Units and the exercise price of the vested unit rights outstanding under the plan. No obligation has been recorded at December 31, 2009 in accounts payable and accrued liabilities (2008 - $0.3 million) as the 7,233,661 outstanding Trust Unit Rights (2008 – 8,037,446) were settled with the acquisition of Harvest by the KNOC in December 2009.

The following table summarizes the changes in the Trust Unit Rights Incentive Plan:

	Year ended December 31, 2009				Year ended December 31, 2008		
	Unit Appreciation Rights		**Weighted Average Exercise Price**		Unit Appreciation Rights		Weighted Average Exercise Price
Outstanding beginning of year	**8,037,466**	**$**	**21.19**		3,823,683	$	30.74
Granted	**145,000**		**7.90**		5,244,102		15.68
Exercised	**(20,675)**		**23.95**		(68,675)		25.67
Forfeited/settled [(1)]	**(8,161,791)**		**20.98**		(961,644)		28.80
Outstanding before exercise price reductions	**-**		**-**		8,037,466		21.19
Exercise price reductions	**-**		**-**		-		(4.45)
Outstanding, end of year	**-**		**-**		8,037,466		16.74
Exercisable before exercise price reductions	**-**	**$**	**-**		85,200	$	22.60
Exercise price reductions	**-**		**-**		-		(15.49)
Exercisable, end of year	**-**	**$**	**-**		85,200	$	7.11

(1) Trust Unit Rights of 7,233,661 were settled on December 22, 2009 subsequent to the closing of the acquisition of Harvest by KNOC (2008 – nil).

Unit Award Plan

The Unit Award Plan authorized Harvest to grant awards of Trust Units to directors, officers, employees and consultants of Harvest and its affiliates. Awards vested annually over a two to four year period and, upon vesting, entitled the holder to elect to receive the number of Trust Units subject to the award or the equivalent cash amount. Harvest recognized a liability on its consolidated balance sheet associated with the awards granted under the plan. This obligation represented the fair value of the vested Trust Units granted under the Unit Award Plan. No obligation has been recorded at December 31, 2009 in accounts payable and accrued liabilities (2008 - $3.6 million) as the 629,347 outstanding Unit Awards (2008 – 659,137) were settled with the acquisition of Harvest by the KNOC in December 2009.

Number	**December 31, 2009**	December 31, 2008
Outstanding, beginning of year	**659,137**	348,248
Granted	**17,732**	390,274
Adjusted for distributions	**93,523**	75,310
Exercised	**(101,652)**	(121,776)
Forfeitures/settled [(1)]	**(668,740)**	(32,919)
Outstanding, end of year	**-**	659,137
Exercisable, end of year	**-**	238,817

(1) Unit Awards of 629,347 were settled on December 31, 2009 subsequent to the closing of the acquisition of Harvest by KNOC (2008 – nil).

In conjunction with the KNOC acquisition, each of the Trust Unit Rights Incentive Plan and the Unit Award Plan was cancelled and $8.3 million was required to be paid to directors, officers and employees. The Trust had accrued $5.6 million of costs associated with the plans prior to the cancellation of the plans; on cancellation of the plans the Trust recorded an additional $2.7 million of costs of which $2.2 million has been included in KNOC acquisition related costs in the consolidated statements of income and $0.5 million was included in general and administrative expense.

Total non cash compensation recovery included in G&A is $5.2 million (2008 – recovery of $1.7 million).

18. Income Taxes

The future income tax ("FIT") provision reflects the net tax effects of temporary differences between the carrying amounts of assets and liabilities of the corporate subsidiaries in the Trust and their corresponding income tax bases as at that date. Changes in the temporary differences are reflected in FIT expense (recovery). Those changes that arise due to a change in capital structure are charged to equity.

As a result of the acquisition by KNOC on December 22, 2009, Harvest is no longer a public trust and is therefore no longer subject to the SIFT tax legislation that passed in Bill C-52 in June 2007 which made the distributions of publicly traded trusts subject to tax. Management does not intend on having income accumulate in the trust; however, in the event that this occurred, tax free distributions could be made to KNOC Canada to eliminate any taxable income. This results in an effective tax rate of zero for Harvest's flow through entities which led to the reversal of the remaining FIT liability that was initially booked upon the enactment of the SIFT rates in the second quarter of 2007. A recovery of $224.7 million relating to this reversal was realized through equity during 2009 as it arose from a change in shareholder status, a recovery of $1.1 million was recognized in unitholders' capital as it related to a capital transaction and a recovery of $28.0 million was credited through the income statement; the additional movement was due to a FIT asset of $14.9 million being recorded on the Pegasus acquisition.

At the end of 2009, Harvest had a net FIT asset on the balance sheet of $64.8 million comprised of a $91.0 million FIT liability for the downstream corporate entities and an offsetting FIT asset of $155.8 million for the upstream corporate entities as compared to a FIT liability of $204.0 million comprised of a $372.6 million provision for our various flow through entities and a $168.6 million net asset for our corporate entities at the end of the prior year.

FIT liability (asset)	
Opening FIT Liability, January 1, 2009	203,998
Ending FIT Asset, December 31, 2009	(64,822)
	(268,820)
Consists of:	
FIT recovery for period ended December 31, 2009	(28,035)
FIT asset recognized on Pegasus acquisition	(14,991)
FIT related to SIFT moved to equity	(224,723)
FIT related to share issuance costs	(1,071)
Total	(268,820)

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		
		2009		2008
Income (loss) before taxes	**$**	**(964,178)**	$	320,498
Combined Canadian Federal and Provincial statutory income tax rate		**29.23%**		29.85%
Computed income tax expense (recovery) at statutory rates		**(281,829)**		95,669
Increased expense (recovery) resulting from the following:				
Income earned by flow through entities		**(48,162)**		(164,571)
Goodwill write-down		**258,416**		
Transfer of intangibles from trust to corporation		**34,199**		
Temporary differences acquired in excess of fair value limitation				944
Benefit of future tax deductions previously unrecognized		**(8,172)**		-
Difference between current and expected tax rates		**(57,482)**		113,655
Non-taxable portion of capital (gain) loss		**(5,936)**		8,216
Change in estimates of future temporary differences		**52,158**		54,005
Non-deductible expenses		**28,773**		642
FIT expense		**(28,035)**		108,560

The components of the FIT (asset)/liability are as follows:

		December 31		
		2009		2008
Net book value of petroleum and natural gas assets in excess of tax pools	$	**214,584**	$	498,725
Net book value of intangible assets in excess of tax pools		**9,681**		16,640
Asset retirement obligation		**(52,129)**		(73,899)
Net unrealized losses related to risk management contracts and currency exchange positions – current		**(3,248)**		7,124
Net unrealized losses related to risk management contracts and currency exchange positions – long-term		**6,681**		1,177
Non-capital loss carry forwards for tax purposes		**(239,513)**		(241,660)
Deferral of taxable income in partnership		**681**		554
Future employee retirement costs		**(1,514)**		(3,135)
Working capital and other items		**(45)**		(1,528)
FIT liability (asset), net	$	**(64,822)**	$	203,998

There are approximately $1.0 billion of temporary differences in the consolidated flow-through entities within the Trust on which FIT has not been recognized.

The expiry dates on the consolidated non-capital losses are as follows:

Year of Expiry	
2013	**$9,768**
2014	**40,411**
2023	**366**
2024	**902**
2025	**97,444**
2026	**40,698**
2027	**457,336**
2028	**353,884**
2029	**118,424**
Consolidated non-capital losses	**$1,119,233**

See Commitments and Contingencies [Note 22].

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, 2009		December 31, 2008	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Discount rate	**5.5%**	**5.5%**	7.25%	7.25 %
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	**-**	**9%**	-	10%
Expected average remaining service lifetime (years)	**12.2**	**10.5**	11.7	10.7

The assets of the defined benefit plan are invested and maintain the following asset mix:

	December 31, 2009	December 31, 2008
Bonds/fixed income securities	**31%**	36%
Equity securities	**69%**	64%

Total cash payments for employee future benefits, consisting of cash contributed by Harvest to the pension plans and other benefit plans was $4.8 million for 2009 (2008 - $3.7 million).

The expected long-term rates of return are estimated based on many factors, including the expected forecast for inflation, risk premiums for each class of asset, and current and future financial market conditions.

The defined benefit pension plans and post-retirement health care benefits plan were subject to actuarial valuations on December 31, 2009; the next valuation reports are due no later than December 31, 2010.

	December 31, 2009		December 31, 2008	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Employee benefit obligation, beginning of year	**$ 40,652**	**$ 5,298**	$ 49,082	$ 6,653
Current service costs	**1,182**	**216**	3,355	370
Interest	**3,084**	**392**	2,673	346
Actuarial losses (gains)	**13,317**	**1,462**	(13,086)	(1,795)
Benefits paid	**(1,759)**	**(321)**	(1,372)	(276)
Employee benefit obligation, end of year	**56,476**	**7,047**	40,652	5,298
Fair value of plan assets, beginning of year	**35,132**	**-**	38,903	-
Actual return on plan assets	**6,510**	**-**	(7,587)	-
Employer contributions	**4,605**	**224**	3,485	199
Employee contributions	**1,582**	**97**	1,703	77
Benefits paid	**(1,759)**	**(321)**	(1,372)	(276)
Fair value of plan assets, end of year	**46,070**	**-**	35,132	-
Funded status	**(10,406)**	**(7,047)**	(5,520)	(5,298)
Unamortized balances:				
Net actuarial losses	**8,059**	**-**	267	-
Carrying amount	**$ (2,347)**	**$ (7,047)**	$ (5,253)	$ (5,298)

	December, 31, 2009	December, 31, 2008
Summary:		
Pension plans	**$ 2,347**	$ 5,253
Other benefit plans	**7,047**	5,298
Carrying amount	**$ 9,394**	$ 10,551

Estimated pension and other benefit payments to plan participants which reflect expected future service, expected to be paid from 2010 to 2019, are as follows:

	Pension Plans	**Other Benefit Plans**
2010	**$ 1,667**	**$ 382**
2011	**1,926**	**543**
2012	**2,144**	**655**
2013	**2,419**	**786**
2014	**2,887**	**943**
2015 to 2019	**21,663**	**7,303**
Total	**$ 32,706**	**$ 10,612**

The table below shows the components of the net benefit plan expense:

	Year ended December 31, 2009		Year ended December 31, 2008	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Current service cost	**$ 1,182**	**$ 216**	$ 3,355	$ 370
Interest costs	**3,084**	**392**	2,673	346
Expected return on assets	**(2,558)**	**-**	(2,806)	-
Amortization of net actuarial (gains)/losses	**(8)**	**1365**	-	(1,872)
Net benefit plan expense	**$ 1,700**	**$ 1,973**	$ 3,222	$ (1,156)

A 1% percent change in the expected health care cost trend rate would have the following annual impacts as at December 31, 2009:

	1% Increase	1% Decrease
Impact on post-retirement benefit expense	$ 1	$ (2)
Impact on projected benefit obligation	16	(25)

20. Financial Instruments and risk management contracts

Financial instruments of Harvest consist of cash, accounts receivable, accounts payable and accrued liabilities, bank loan, risk management contracts, Convertible Debentures and the 77/8% Senior Notes. The carrying value and fair value of these financial instruments at December 31, 2009 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, 2009:

	Carrying Value	Fair Value	Gains/ (Losses)	Interest Income/ (Expense)	Other Income/ (Expense)
Loans and Receivables					
Accounts receivable	$ 180,839	$ 180,839	$ -	$ 130 [2]	$ -
Assets Held for Trading					
Net fair value of risk management contracts	(2,052)	(2,052)	(24,899) [3]	-	-
Other Liabilities					
Accounts payable[6]	205,378	205,378	-	-	-
Bank loan	428,017	428,017	-	(16,582) [4]	(930)[4]
$7^{7/8}$% Senior Notes	259,119 [1]	265,378	-	(24,413) [5]	-
Convertible Debentures	$ 837,870	$ 931,067	$ -	$ (77,914) [5]	$ -

[1] The face value of the $7^{7/8}$% Senior Notes at December 31, 2009 is $262.8 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.
[6] Excludes current portion of asset retirement obligation

(a) Fair Values

The fair values of the Convertible Debentures and the 77/8% Senior Notes are based on quoted market prices as at December 31, 2009. 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.

Harvest's financial assets and liabilities recorded at fair value have been classified according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Harvest's cash and risk management contracts have been assessed on the fair value hierarchy described above; cash is classified as Level 1 and risk management contracts as Level 2.

(b) Risk Management Contracts

At December 31, 2009, the net fair value deficiency reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $2.1 million (2008 – net fair value asset of $35.9 million), which is presented on the balance sheet as a current liability.

The following is a summary of Harvest's risk management contracts outstanding, along with their fair value at December 31, 2009:

Quantity	Type of Contract	Term	Average Price	Fair value
Electricity Price Risk Management				
25 MWh	Electricity price swap contracts	Jan. 10 – Dec. 10	Cdn $59.22	$ (2,052)

For the year ended December 31, 2009, the total unrealized loss recognized in the consolidated statement of income and comprehensive income on the change in fair value of risk management contracts was $37.9 million (2008 – gain of $185.9 million). The realized gains and losses on all risk management contracts are included in the period in which they are incurred.

(c) Risk Exposure

Harvest is exposed to market risks resulting from fluctuations in commodity prices, currency exchange rates and interest rates in the normal course of operations. Harvest is also exposed, to a lesser extent, to credit risk on accounts receivable 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 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 limited 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, 2009 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, 2009, Harvest had an accounts receivable balance with one customer of $23.6 million resulting from the sale of refined product, representing approximately 35% 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, 2009 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	$ 93,735	$ 346	$ 435	$ 265	$ 14,065[1]
Risk Management Contract Counterparties	3,357	-	-	-	-
Downstream Accounts Receivable	62,238	2,902	755	374	2,367
Total	**$ 159,330**	**$ 3,248**	**$ 1,190**	**$ 639**	**$ 16,432**

[1] Includes a $4.2 million allowance for doubtful accounts.

(ii.) Liquidity Risk

Harvest is exposed to liquidity risk due to our borrowings under our credit facilities, convertible debentures and 77/8% Senior Notes. 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, 2009 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	$ 188,848	$ -	$ -	$ -	**$ 188,848**
Settlement of risk management contract	2,052	-	-	-	**2,052**
Bank loan and interest	429,646	-	-	-	**429,646**
Convertible debentures and interest	236,173	211,435	448,992	243,891	**1,140,491**
$7^{7/8}$% Senior Notes and interest	60,272	233,892	-	-	**294,164**
Pension contributions	4,100	8,448	8,789	4,527	**25,864**
Asset retirement obligations	12,178	40,071	25,893	1,123,473	**1,201,615**
Total	**$ 933,269**	**$ 493,846**	**$ 483,674**	**$1,371,891**	**$3,282,680**

(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 77/8% 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, 2009, interest charges on bank loans aggregated to $16.1 million (2008 - $49.6 million), reflecting an effective interest rate of 1.44% (2008 – 4.12%).

At December 31, 2009, if interest rates had decreased by 100% with all other variables held constant, after-tax net income for the year would have been $1.3 million higher, as a result of lower interest expense on variable rate borrowings. If interest rates had increased by 250%, with all other variables held constant, the after-tax net income would have been $3.3 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 77/8% 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, 2009, 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	$	(21,057)
U.S. Dollar Exchange Rate - 8% decrease	$	21,057

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	$	(22,978)
Canadian Dollar Exchange Rate - 8% decrease	$	22,978

Commodity Price Risk

Harvest uses price risk management contracts to manage a portion of its 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 power price. 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. Harvest uses power hedge contracts as an effective method of reducing its cash power expense.

If the following changes in expected forward prices were applied to the fair value of risk management contracts in place at December 31, 2009, net income would be impacted as follows:

		Impact on Net Income			
Contract	**% Change**	**Due to % increase**		**Due to % decrease**	
Power	50%	$	-	$	(36)
Total		**$**	**-**	**$**	**(36)**

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	
	2009	2008	**2009**	2008	**2009**	2008
Revenue[2]	**$ 2,381,637**	$ 4,194,595	**$ 886,308**	$ 1,543,214	**$ 3,267,945**	$ 5,737,809
Royalties	**-**	-	**(128,860)**	(248,445)	**(128,860)**	(248,445)
Less:						
Purchased products for resale and processing	**2,015,671**	3,850,507	**-**	-	**2,015,671**	3,850,507
Operating[3]	**241,911**	236,259	**258,675**	300,890	**500,586**	537,149
Transportation and marketing	**12,009**	20,753	**14,228**	13,490	**26,237**	34,243
General and administrative	**1,593**	1,875	**36,452**	32,868	**38,045**	34,743
Depletion, depreciation, amortization and accretion	**77,288**	71,076	**450,291**	448,735	**527,579**	519,811
Goodwill impairment[5]	**206,465**	-	**677,612**	-	**884,077**	-
	$ (173,300)	$ 14,125	**$ (679,810)**	$ 498,786	**(853,110)**	512,911
Realized net gains (losses) on risk management contracts					**62,803**	(200,782)
Unrealized net losses on risk management contracts					**(37,904)**	185,921
Korea National Oil Corporation transaction costs					**(18,393)**	-
Interest and other financing charges on short term debt					**(8,896)**	(295)
Interest and other financing charges on long term debt					**(110,943)**	(146,375)
Currency exchange gain (loss)					**2,265**	(30,882)
Large corporations tax (expense) recovery and other tax					**509**	81
Future income tax (expense) recovery					**28,035**	(108,560)
Net (loss) income					**$ (935,634)**	$ 212,019
Total Assets[4]	**$ 1,362,941**	$ 1,775,688	**$ 3,041,971**	$ 3,933,632	**$ 4,404,912**	$ 5,745,407
Capital Expenditures						
Development and other activity	**$ 43,875**	$ 56,162	**$ 186,276**	$ 271,312	**$ 230,151**	$ 327,474
Business acquisitions	**-**	-	**-**	36,756	**-**	36,756
Property acquisitions	**-**	-	**2,635**	138,493	**2,635**	138,493
Property dispositions	**-**	-	**(64,751)**	(46,476)	**(64,751)**	(46,476)
Total expenditures	**$ 43,875**	$ 56,162	**$ 124,160**	$ 400,085	**$ 168,035**	$ 456,247
Property, plant and equipment						
Cost	**$ 1,328,727**	$ 1,493,039	**$ 4,848,984**	$ 4,710,725	**$ 6,177,711**	$ 6,203,764
Less: Accumulated depletion, depreciation, and amortization	**(205,637)**	(162,810)	**(1,998,004)**	(1,572,449)	**(2,203,641)**	(1,735,259)
Net book value	**$ 1,123,090**	$ 1,330,229	**$ 2,850,980**	$ 3,138,276	**$ 3,974,070**	$ 4,468,505
Goodwill[5]						
Beginning of year	**$ 216,229**	$ 175,984	**$ 677,612**	$ 676,794	**$ 893,841**	$ 852,778
Addition (reduction) to goodwill	**(9,764)**	40,246	**-**	817	**(9,764)**	41,063
Impairment of goodwill	**(206,465)**	-	**(677,612)**	-	**(884,077)**	-
End of year	**$ -**	$ 216,230	**$ -**	$ 677,611	**$ -**	$ 893,841

[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, 2009, two customers represent sales of $1,459.7 million and $391.1 million respectively (2008 - $2,818.1 million and $592.0 million). 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, 2009 include $47.5 million of turnaround and catalyst costs (2008 - $5.6 million).
[4] Total Assets on a consolidated basis includes nil (2008 - $36.1 million) relating to the fair value of risk management contracts.
[5] A goodwill impairment charge of $206.5 million for the downstream segment was recognized at June 30, 2009 and of $677.6 million was recognized for the upstream segment at September 30, 2009 (see Note 7).
[6] There is no intersegment activity.

22. Commitments and Contingencies

From time to time, Harvest is involved in litigation or has claims brought against it in the normal course of business operations. Management of Harvest is not currently aware of any claims or actions that would materially affect Harvest's reported financial position or results from operations. In the normal course of operations, management may also enter into certain types of contracts that require Harvest to indemnify parties against possible third party claims, particularly when these contracts relate to purchase and sale agreements. The terms of such contracts vary and generally a maximum is not explicitly stated; as such the overall maximum amount of the obligations cannot be reasonably estimated. Management does not believe payments, if any, related to such contracts would have a material effect on Harvest's reported financial position or results from operations.

The following are the significant commitments and contingencies at December 31, 2009:

(a) North Atlantic has a Supply and Offtake Agreement with Vitol Refining S.A. ("Vitol") which was revised effective November 1, 2009 for a primary term of two years after which the agreement will revert to evergreen. This agreement continues to provide that the ownership of substantially all crude oil feedstock and refined product inventory at the refinery be retained by Vitol and that Vitol 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. The revised terms also include the marketing of high sulphur fuel oil inventories which, along with other amendments, will increase the amount of working capital financing provided by Vitol. At December 31, 2009, North Atlantic had commitments totaling approximately $582.0 million (2008 - $319.7 million) in respect of future crude oil feedstock purchases and related transportation from Vitol.

(b) 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 $3.4 million and are included in the table below; costs cannot yet be estimated for the remaining projects.

(c) 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.

(d) Suncor Energy (formerly 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

(e) 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. Harvest has filed a Notice of Objection with the CRA and filed a Notice of Appeal with the Tax Court. The CRA has advised that they will file their Reply/Statement of Defense shortly and Harvest has now scheduled examinations for discovery for April 2010.

The following is a summary of Harvest's contractual obligations and commitments as at December 31, 2009:

	Payments Due by Period						
	2010	**2011**	**2012**	**2013**	**2014**	**Thereafter**	**Total**
Debt repayments (1)	650,687	220,254	106,796	330,548	60,050	236,599	**1,604,934**
Debt interest payments(2)	75,404	66,537	51,740	39,957	18,437	7,292	**259,367**
Capital commitments(3)	19,173	1,817	-	-	-	-	**20,990**
Operating leases(4)	6,506	7,475	6,854	6,205	6,126	1,159	**34,325**
Pension contributions(5)	4,100	4,182	4,266	4,351	4,438	4,527	**25,864**
Transportation agreements(6)	3,131	1,694	631	205	-	-	**5,661**
Feedstock commitments(7)	582,050	-	-	-	-	-	**582,050**
Contractual obligations	**1,341,051**	**301,959**	**170,287**	**381,266**	**89,051**	**249,577**	**2,533,191**

(1) Included in the 2010 period is the principal amount of convertible debentures and 7 7/8% Senior Notes redeemed subsequent to year end [see note 23].
(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.
(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. Subsequent Events

Between January 1, 2010 and March 3, 2010, an additional $54.4 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].

On January 7, 2010 the downstream operations experienced a fire at the refinery in the conversion section of the operating units. As a result, this section of the refinery was shut-down for assessment and repairs. Subsequent to the fire, the remaining operating units were also shut-down for other repairs and economic reasons. The current assessment of the cost of repairs from the fire is approximately $7.0 million with an estimated downtime of six to eight weeks.

On January 20, 2010, Harvest made an offer to purchase 100% of the outstanding Convertible Debentures for cash consideration of 101% of the principal amount thereof plus accrued and unpaid interest in accordance with the "change of control" provisions included within the indenture pursuant to which the Convertible Debentures were issued. The expiry date of each offer is as follows:

Series	Face Value at December 31, 2009	Carrying Value at December 31, 2009	Expiry Date of offer:
6.5% Debentures due 2010	37,062	36,187	March 4, 2010
6.4% Debentures due 2012	174,626	170,667	February 11, 2010
7.25% Debentures due 2013	379,256	362,216	March 4, 2010
7.25% Debentures due 2014	73,222	68,458	February 25, 2010
7.5% Debentures due 2015	250,000	200,342	February 25, 2010
	914,166	837,870	

As at March 4th all of the offers have expired and the following redemptions have been made:

- 6.5% Debentures due 2010 – $13.3 million principal amount tendered leaving a principal balance of $23.8 million outstanding
- 6.4% Debenture due 2012 – $67.8 million principal amount tendered leaving a principal balance of $106.8 million outstanding
- 7.25% Debentures due 2013 – $48.7 million principal amount tendered leaving a principal balance of $330.5 million outstanding
- 7.25% Debentures due 2014 – $13.2 million principal amount tendered leaving a principal balance of $60.1 million outstanding
- 7.5% Debentures due 2015 – $13.4 million principal amount tendered leaving a principal balance of $236.6 million outstanding

On January 20, 2010, Harvest made an offer to purchase 100% of the outstanding 7 7/8% Senior Notes for cash consideration of 101% of the principal amount thereof plus accrued and unpaid interest in accordance with the "change of control" provisions included within the indenture pursuant to which the 7 7/8% Senior Notes were issued. On February 16, 2010, the offer relating to the 7 7/8% Senior Notes expired and US$40.4 million principal amount was tendered, leaving a principal balance of US$209.6 million outstanding.

On January 29, 2010 Harvest issued 46,567,852 Trust Units to Korea National Oil Corporation at $10.00 per Unit. The total proceeds of $465.7 million were used to repay the credit facility and to establish funding for potential convertible debenture or 7 7/8% Senior Note redemptions under the "change of control" provisions included within the relevant indentures.

In December 2009 Harvest signed a conditional letter of intent to purchase certain petroleum and natural gas assets in exchange for $31.0 million. The letter of intent is subject to certain conditions, including approval by Harvest's Board of Directors which was received in January 2010. The acquisition is not expected to close until mid March; upon completion of this purchase, the production from these properties will be included in Harvest's results.

24. Comparatives

Certain comparative figures have been reclassified to conform to the current year's presentation.