Financial & Operating Highlights

The table below provides a summary of our financial and operating results for three month periods ended March 31, 2009 and 2008.

	Three Months Ended March 31		
($000s except where noted)	**2009**	2008	Change
Revenue, net[1]	**731,095**	1,377,352	(47%)
Cash From Operating Activities	**221,745**	128,119	73%
Per Trust Unit, basic	**$ 1.40**	$ 0.85	65%
Per Trust Unit, diluted	**$ 1.28**	$ 0.83	54%
Net Income (Loss)[2]	**56,864**	(346)	- %
Per Trust Unit, basic	**$ 0.36**	$ -	- %
Per Trust Unit, diluted	**$ 0.36**	$ -	- %
Distributions declared	**103,302**	135,167	(24%)
Distributions declared, per Trust Unit	**$ 0.65**	$ 0.90	(28%)
Distributions declared as a percentage of Cash From Operating Activities	**47%**	106%	(59%)
Bank debt	**1,233,843**	1,330,423	(7%)
$7^{7/8}$% Senior Notes	**309,325**	250,099	24%
Convertible Debentures[3]	**830,757**	628,929	32%
Total long-term financial debt[3]	**2,373,925**	2,209,451	7%
Total assets	**5,785,269**	5,574,528	4%
UPSTREAM OPERATIONS			
Daily Production			
Light to medium oil (bbl/d)	**24,233**	25,509	(5%)
Heavy oil (bbl/d)	**11,141**	12,980	(14%)
Natural gas liquids (bbl/d)	**2,837**	2,484	14%
Natural gas (mcf/d)	**95,421**	102,570	(7%)
Total daily sales volumes (boe/d)	**54,115**	58,067	(7%)
Operating Netback ($/boe)	**16.45**	45.34	(64%)
Cash capital expenditures	**108,710**	79,571	37%
Business and property acquisitions, net	**675**	185	265%
DOWNSTREAM OPERATIONS			
Average daily throughput (bbl/d)	**104,296**	111,999	(7%)
Average Refining Margin (US$/bbl)	**15.18**	8.90	71%
Cash capital expenditures	**6,904**	6,027	15%

(1) Revenues are net of royalties.

(2) Net Income (Loss) includes a future income tax expense of $2.0 million (2008 – recovery of $21.8 million) and an unrealized net loss from risk management activities of $10.2 million (2008 - net losses of $60.9 million) for the three months ended March 31, 2009.

(3) Includes current portion of Convertible Debentures and excludes the equity component of Convertible Debentures.

Message to Unitholders

First quarter 2009 highlighted the benefit of having a diversified and integrated business model. While contributions from the upstream business continue to be affected by the significant decline in commodity prices, our downstream refining business reported record results. Cash from Operating Activities of $221.7 million ($1.40 per unit), represents a 21% increase over the previous quarter and a 73% increase over the same period last year. This strong cash contribution contributed to a low payout ratio (distributions declared divided by cash from operating activities) of 47%.

Given our focus of balancing the sources and uses of cash and debt reduction objectives, we have maintained the distribution at $0.05 per unit, subject to monthly review.

Upstream

The first quarter of 2009 was a challenging period for upstream western Canadian operations due to reduced commodity prices. Cash flow declined to $71.3 million, compared to $230.8 in the same period last year. However we are pleased with the operating results. Production volumes were above our expectations as we continued to benefit from our enhanced oil recovery projects as well as new drilling activities. In light of the lower commodity prices, we have introduced a number of initiatives to reduce costs which we are starting to see the benefits from and we should see continued improvements in future quarters.

Spending in the quarter amounted to $108.7 million, a 37% increase compared to the same period last year. Harvest concentrated its efforts in the Hay River area of northeast British Columbia with approximately 60% of our total first quarter capital dedicated to this winter only access area. At Hay River, we drilled 43 wells - 20 multi-leg horizontal producers, 18 horizontal injection wells, 4 water source wells and 1 stratigraphic test well. Production volumes in the area have now increased to approximately 7,000 boe/d. We have also identified an extension of this Bluesky oil pool through a stratigraphic test well, which should prove to expand our original oil in place and inventory of drillable locations.

We have also seen the results of successful new drilling in other areas. In the Chedderville area of west central Alberta, we followed up a successful well drilled in late 2007 and produced through 2008 at over 700 boe/d, with 3 additional wells that were tied-in late 2008, and 3 new drilling locations in Q1. This has been an extremely successful growth area for Harvest with current production of approximately 2,000 boe/d from the original 4 wells.

We continue to focus on our Enhanced Oil Recovery projects and are pleased with results to date. Improving pressure support in our large fields will help to reduce decline rates, enhance recovery and extend field life.

We are pleased with our drilling and production progress so far this year and we continue to anticipate average production of 50,000 boe/d in 2009. Harvest Energy continues to be positioned with short term growth opportunities coupled with long-term enhanced recovery prospects with over 2 billion barrels of estimated original oil in place on conventional land. Future EOR opportunities that could be implemented as early as 2009 have been identified in Hayter, Hay River, Kindersley and southeast Saskatchewan, while carbon dioxide (CO_2)flooding and sequestration, oilsands and coal bed methane (CBM) opportunities represent longer term recovery opportunities for Harvest.

Downstream

Harvest Energy's refining and marketing business in Newfoundland and Labrador reported record results as stronger refining margins and lower purchased energy costs more than offset a decline in refinery throughput due to end of run activity of the hydrocracker, distillate hydrotreater, and platformer catalysts. Cash from downstream operations of $142.0 million increased 480% from the same period last year as refining margins averaged US$15.18/bbl or a US$6.28/bbl increase over the same period last year. These downstream results represent the strongest overall performance in the history of the North Atlantic refinery.

We continue to benefit in the quarter from a refined product mix more heavily weighted toward distillate products (ultra low sulphur diesel and jet fuel) than most North American refiners who experienced relatively weaker margins on refined gasoline products. Output in the quarter of 104,296 bbls/d was weighted 38% to distillates (ultra low sulphur diesel and jet fuel), 36% to gasoline and related products and 26% to heavy fuel oil. The distillate yield will be restored to approximately 45% in the second half of 2009 due to the replacement of the hydrocracker catalyst.

During the second quarter, we have completed a turnaround and catalyst replacement of the hydrocracker, replacement of the distillate hydrotreater catalyst, regeneration of the platformer catalyst, and refurbishment of several other process and utility units at a planned cost of $45 million. Additionally, we have invested $22 million in capital projects that further enhance the reliability and profitability of the refinery, including the expansion of the hydrocracker capacity by approximately 1,000 bbls/d. This was strategically timed to take advantage of a window of weak refining margins and as operations at the refinery start back up, we are seeing a trend of improving margins. Even though we do not anticipate the first quarter of 2009 to be reflective of Harvest's refining margins for the remainder of the year, 2009 looks to be a strong year in our refining business.

Corporate

Harvest's integrated business model and strong operational results have proven to diversify cash from operating activities leading to sequential cash flow per unit growth that will likely lead western Canadian oil and gas companies. With the majority of our full year $170 upstream capital spending budget taking place in the first quarter, we are pleased with the results achieved and are expecting good operational performance for the remainder of the year. With that, we maintain the 2009 production guidance of 50,000 boe/d comprised of 35,000 bbl/d of oil and natural gas liquids and 90,000 mcf/d of natural gas. We continue to focus on projects that provide good opportunities and attractive rates of return even with current commodity prices. We continue to anticipate operating costs will be approximately $15.50/boe with royalties as a percent of revenue of 16.5% or less.

Downstream throughput will be reduced in the second quarter as the planned shut-down of the North Atlantic Refinery for the hydrocracker catalyst replacement and other improvements was under way. While down, we took advantage of opportunities to accelerate some planned equipment maintenance on the crude unit and accelerate a catalyst change on the distillate hydrotreater. We are now expecting throughput for the year to average 98,000 bbl/d.

Protecting our people, our partners, our stakeholders and the environment are key elements of our business. While we are active throughout the organization, we never lose sight of the fact that safe and environmentally friendly business practices are critical to our social license to operate. In all aspects of our business, we are committed to minimizing our environmental footprint, being a good and responsible corporate citizen, and conducting all of our affairs in an environmentally and socially responsible manner.

The first quarter of 2009 was a challenging period for many western Canadian oil and gas operators. Harvest Energy's diverse assets provided record contribution from our downstream assets largely offsetting reductions in our upstream business. As we look forward, Harvest continues to focus on debt repayment to improve the balance sheet as well as progressing opportunities to divest non-core properties.

In closing, we thank all of our stakeholders for your ongoing support of and interest in Harvest Energy.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of the financial condition and results of operations of Harvest Energy Trust should be read in conjunction with our audited consolidated financial statements and accompanying notes for the years ended December 31, 2008 and 2007, our MD&A for the year ended December 31, 2008 as well as our interim consolidated financial statements and notes for the three month period ended March 31, 2009 and 2008. The information and opinions concerning our future outlook are based on information available at May 11, 2009.

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

NON-GAAP MEASURES

Throughout this MD&A we have referred to certain measures of financial performance that are not specifically defined under Canadian GAAP. Cash G&A and Operating Netbacks are non-GAAP measures used extensively in the Canadian energy trust sector for comparative purposes. Cash G&A are G&A expenses excluding the effect of our unit based compensation plans, while Operating Netbacks are always reported on a per boe basis, and include gross revenue, royalties, operating expenses, and transportation and marketing expenses. Gross Margin is also a non-GAAP measure and is commonly used in the refining industry to reflect the net funds received from the sale of refined products after considering the cost to purchase the feedstock and is calculated by deducting purchased products for resale and processing from total revenue. Earnings From Operations and Cash From Operations are also non-GAAP measures and are commonly used for comparative purposes in the petroleum and natural gas and refining industries to reflect operating results before items not directly related to operations. This information may not be comparable to similar measures by other issuers.

FORWARD-LOOKING INFORMATION

This MD&A highlights significant business results and statistics from our consolidated financial statements for the three months ended March 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, 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 – First Quarter 2009

- Cash flow from operating activities of $221.7 million as compared to $128.1 million in the prior year reflects a $117.5 million improvement in the contribution from our downstream operations as well as a $61.8 million favourable change in the settlements of our commodity price risk management contracts more than offsetting a $159.5 million drop in the contribution from our upstream operations while a $70.3 million change in working capital requirements accounts for the balance.
- Upstream operating cash flow of $71.3 million in 2009 reflects substantially weaker commodity prices along with a drop in our average daily production to 54,115 boe/d as compared to 55,177 boe/d and 58,067 boe/d in the Fourth Quarter and First Quarter of the prior year, respectively.
- Upstream capital spending of $108.7 million includes the drilling of 82 wells with a success ratio of 100% with the primary focus on a substantial drilling program in Hay River.
- Downstream operating cash flow of $142.0 million in 2009, a 480% improvement over the $24.5 million reported in the prior year, reflects the cumulative benefit of improved refining margins including significant gains from operational hedging, a weakening of the Canadian dollar and a drop in the price of purchased energy along with stable refinery operations. This is a record level of cash flow surpassing the $138.4 million achieved in the Second Quarter of 2007.
- Cash receipts totaled $25.5 million in 2009 on the settlement of 20,000 bbl/d of refined products price risk management contracts in place for the First Quarter as compared to payments of $36.3 million in prior year.
- Monthly distributions of $0.30 per trust unit for January and February and $0.05 for March aggregate to a 47% Payout Ratio for the quarter.

SELECTED INFORMATION

The table below provides a summary of our financial and operating results for the three months ended March 31, 2009 and 2008.

	Three Months Ended March 31		
($000s except where noted)	**2009**	2008	Change
Revenue, net[1]	**731,095**	1,377,352	(47%)
Cash From Operating Activities	**221,745**	128,119	73%
Per Trust Unit, basic	**$ 1.40**	$ 0.85	65%
Per Trust Unit, diluted	**$ 1.28**	$ 0.83	54%
Net Income (Loss)[2]	**56,864**	(346)	-%
Per Trust Unit, basic	**$ 0.36**	$ -	-%
Per Trust Unit, diluted	**$0.36**	$ -	-%
Distributions declared	**103,302**	135,167	(24%)
Distributions declared, per Trust Unit	**$ 0.65**	$ 0.90	(28%)
Distributions declared as a percentage of Cash From Operating Activities	**47%**	106%	(59%)
Bank debt	**1,233,843**	1,330,423	(7%)
7 7/8% Senior Notes	**309,325**	250,099	24%
Convertible Debentures[3]	**830,757**	628,929	32%
Total long-term financial debt[3]	**2,373,925**	2,209,451	7%
Total assets	**5,785,269**	5,574,528	4%
UPSTREAM OPERATIONS			
Daily Production			
Light to medium oil (bbl/d)	**24,233**	25,509	(5%)
Heavy oil (bbl/d)	**11,141**	12,980	(14%)
Natural gas liquids (bbl/d)	**2,837**	2,484	14%
Natural gas (mcf/d)	**95,421**	102,570	(7%)
Total daily sales volumes (boe/d)	**54,115**	58,067	(7%)
Operating Netback ($/boe)	**16.45**	45.34	(64%)
Cash capital expenditures	**108,710**	79,571	37%
Business and property acquisitions, net	**675**	185	265%
DOWNSTREAM OPERATIONS			
Average daily throughput (bbl/d)	**104,296**	111,999	(7%)
Average Refining Margin (US$/bbl)	**15.18**	8.90	71%
Cash capital expenditures	**6,904**	6,027	15%

(4) Revenues are net of royalties.

(5) Net Income (Loss) includes a future income tax expense of $2.0 million (2008 – recovery of $21.8 million) and an unrealized net loss from risk management activities of $10.2 million (2008 - net losses of $60.9 million) for the three months ended March 31, 2009.

(6) Includes current portion of Convertible Debentures and excludes the equity component of Convertible Debentures.

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.

Cash flow from operating activities of $221.7 million in the First Quarter of 2009 is comprised of contributions of $71.3 million and $142.0 million from the upstream and downstream operations, respectively, plus $25.5 million of net cash receipts from our price risk management activities and a $15.3 million net reduction in non-cash working capital less $28.5 million of financing and other costs. As compared to $128.1 million reported in 2008, the year-over-year $93.6 million improvement in cash flow from operating activities is comprised of a $179.3 million combined improvement in refining contribution and price risk management settlements exceeding the drop in contribution from our upstream operations by $19.8 million plus a $70.3 million favourable change in non-cash working capital requirements. In 2009, the reduction in non-cash working capital is comprised of a $12.4 million decrease in accounts receivable and a $19.5 million increase in accounts payable offsetting a $21.4 million build in downstream inventories. The reduction in accounts receivable reflects the impact of lower commodity prices in our upstream business and a change in the net feedstock/refined product settlements in our downstream business from a receivable in 2008 to a payable in 2009. In addition, a portion of our capital spending program remains in payables at the end of the First Quarter of 2009.

Cash flow provided from our upstream operations totaled $71.3 million during the First Quarter of 2009, a drop of $159.5 million as compared to the $230.8 million reported in the prior year. The principal drivers of this reduction is a 56% drop in the West Texas Intermediate benchmark price for crude oil and a 7% reduction in our average daily production offset somewhat by the impact of a weakening Canadian dollar and tightening heavy oil differentials. Our netback price for the First Quarter of 2009 of $16.45 per boe as compared to $45.34 per boe in 2008 reflects the weaker commodity prices as well as a 13% higher operating cost per boe reflecting the impact of a 4% increase in spending and a 7% drop in production volume.

During the First Quarter of 2009, our downstream operations reported a record setting cash flow of $142.0 million as compared to $24.5 million in the prior year. While our average refining margin in the quarter was US$15.18/bbl as compared to US$8.90/bbl in the prior year, a 71% improvement, we also benefited from the weaker Canadian dollar in 2009 as our US dollar denominated gross margin includes a $34.2 million increase due to the translation of these amounts to Canadian dollars as compared to an exchange rate near parity in the prior year. Included in the US dollar denominated gross margin is a US$45.0 million operational hedging gain generated by the month-to-month hedging of the WTI price component of our crude oil feedstock purchase commitments through the Supply and Offtake Agreement. While our 2009 refining operating costs have remained relatively unchanged at $19.2 million ($2.05 per bbl of throughput) for the quarter, the cost of our purchased energy has dropped by $26.5 million to $1.77 per bbl of throughput as compared to $4.23 per bbl of throughput in the prior year. The 61% drop in our purchased energy costs reflects the US$47.03 per bbl drop in price with fuel oil purchased for US$33.91 in the First Quarter of 2009 as well as a 162,000 bbl reduction in the volume of purchased fuel oil due to a 98,000 bbl increase in consumption of internally produced fuel. The refinery throughput of 104,296 bbl/d in the quarter is approximately 7% lower than in the prior year reflecting a reduction required to accommodate the reduced activity level of the catalyst in the hydrocracker, which has now been replaced in the April 2009 turnaround, and other end of run conditions.

Our monthly distributions of $0.30 per Trust Unit for January and February of 2009 and $0.05 per Trust Unit for March 2009 represent 47% of our cash provided from operating activities. During the First Quarter of 2009, the $206.4 million of cash flow from operating activities (which excludes the $15.3 million reduction in non-cash working capital) was sufficient to fund aggregate distribution payments of $73.3 million (which is net of Unitholder participation in our distribution reinvestment programs) and $115.6 million of capital spending resulting in our bank borrowings being substantially unchanged at the end of the quarter as compared to December 31, 2008. At the end of the First Quarter of 2009, our bank debt to annualized earnings before interest, taxes depreciation and amortization ("EBITDA") was 1.5 times and our bank debt to total capitalization was 24%, substantially unchanged from the financial ratios at the end of December 31, 2008.

Business Segments

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

	Three Months Ended March 31					
	2009			2008		
(in $000s)	**Upstream**	**Downstream**	**Total**	Upstream	Downstream	Total
Revenue(1)	**158,391**	**572,704**	**731,095**	314,933	1,062,419	1,377,352
Earnings From Operations(2)	**(44,282)**	**120,574**	**76,292**	113,251	7,740	120,991
Cash From Operations(2)	**71,342**	**142,016**	**213,358**	230,773	24,537	255,310
Capital expenditures	**108,710**	**6,904**	**115,614**	79,571	6,027	85,598
Total assets(3)	**3,928,531**	**1,831,039**	**5,785,269**	3,962,295	1,592,586	5,574,528

(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 March 31, 2009 include $25.7 million (2008 - $19.6 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

First Quarter Highlights

- First Quarter 2009 operating cash flow of $71.3 million, a decrease of $159.5 million over the same period in the prior year, reflecting a year-over-year decrease in commodity prices as well as lower production.
- Average production of 54,115 boe/d during the First Quarter of 2009 as compared to production of 58,067 boe/d in the First Quarter of 2008 and 55,177 boe/d during the Fourth Quarter of 2008 reflects normal decline rates and the impact of reduced capital spending on natural gas and heavy oil in 2008.
- First Quarter 2009 operating netback of $16.45/boe, representing a $28.89/boe (64%) drop over the same period in the prior year, attributed to substantially lower commodity prices.
- First Quarter 2009 capital spending of $108.7 million included the drilling of 82 wells (62.1 on a net basis) with a 100% success rate.

Summary of Financial and Operating Results

	Three Months Ended March 31		
(in $000s except where noted)	**2009**	2008	Change
Revenues	**182,920**	377,333	(52%)
Royalties	**(24,529)**	(62,400)	(61%)
Net revenues	**158,391**	314,933	(50%)
Operating expenses	**75,335**	72,323	4%
General and administrative	**7,394**	11,909	(38%)
Transportation and marketing	**2,932**	3,025	(3%)
Depreciation, depletion, amortization and accretion	**117,012**	114,425	2%
Earnings From Operations[(1)]	**(44,282)**	113,251	(139%)
Cash capital expenditures (excluding acquisitions)	**108,710**	79,571	37%
Property and business acquisitions, net of dispositions	**675**	185	265%
Daily sales volumes			
Light to medium oil (bbl/d)	**24,233**	25,509	(5%)
Heavy oil (bbl/d)	**11,141**	12,980	(14%)
Natural gas liquids (bbl/d)	**2,837**	2,484	14%
Natural gas (mcf/d)	**95,421**	102,570	(7%)
Total (boe/d)	**54,115**	58,067	(7%)

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

Commodity Price Environment

	Three Months Ended March 31		
Benchmarks	**2009**	2008	Change
West Texas Intermediate crude oil (US$ per barrel)	**43.08**	97.90	(56%)
Edmonton light crude oil ($ per barrel)	**49.59**	97.35	(49%)
Bow River blend crude oil ($ per barrel)	**44.09**	77.72	(43%)
AECO natural gas daily ($ per mcf)	**4.92**	7.90	(38%)
Canadian / U.S. dollar exchange rate	**0.804**	0.996	(19%)

The average WTI benchmark price in the First Quarter 2009 was 56% lower than the First Quarter 2008 average price, as the declining global economy continued to precipitate a significant decrease in commodity prices. The average Edmonton light crude oil price ("Edmonton Par") also decreased significantly, resulting in a First Quarter 2009 price of $49.59, a decrease of 49% over the First Quarter of the prior year. The decrease in the Edmonton Par benchmark price has been less than that of the WTI benchmark price due to the weakening of the Canadian dollar relative to the U.S. 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. In the First Quarter of 2009, the decline in crude oil prices resulted in reduced supply of heavy oil as more expensive heavy oil plays became uneconomical, resulting in a tightening of the Bow River heavy oil differential relative to Edmonton Par to an average of $5.50/bbl (11.1%) compared to $19.63/bbl (20.2%) in the First Quarter of 2008.

	2009	2008				2007		
Differential Benchmarks	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Bow River Blend differential to Edmonton Par ($/bbl)	**5.50**	14.07	16.48	21.50	19.63	29.51	23.87	21.12
Bow River Blend differential as a % of Edmonton Par	**11.1%**	22.2%	13.5%	17.1%	20.2%	34.2%	30.0%	29.4%

The average First Quarter 2009 AECO daily natural gas price was 38% lower than the First Quarter of 2008 due to 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 the three months ended March 31, 2009 and 2008.

	Three Months Ended March 31		
	2009	2008	Change
Light to medium oil ($/bbl)	**40.99**	86.54	(53%)
Heavy oil ($/bbl)	**37.16**	69.04	(46%)
Natural gas liquids ($/bbl)	**41.22**	78.04	(47%)
Natural gas ($/mcf)	**5.33**	8.28	(36%)
Average realized price ($/boe)	**37.56**	71.41	(47%)

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

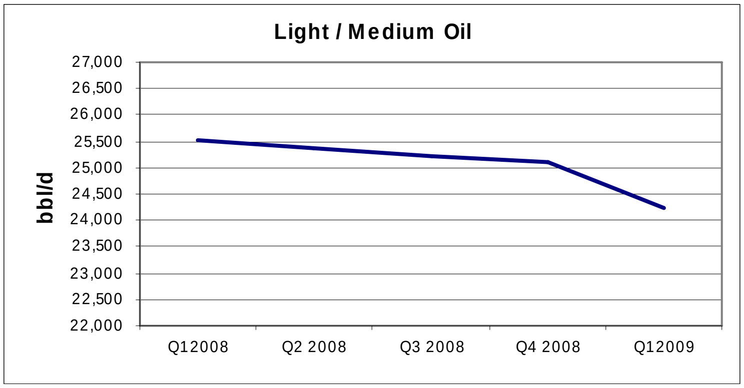
Our realized price for light to medium oil sales decreased by $45.55/bbl (53%) in the First Quarter of 2009 as compared to the same period in the prior year, reflecting the $47.76/bbl (49%) decrease in Edmonton Par pricing. Harvest's heavy oil price decreased by $31.88/bbl (46%) in the First Quarter of 2009 as compared to the same period in the prior year, reflecting the $33.63/bbl (43%) decrease in the Bow River price. Our average realized price for our natural gas production decreased by $2.95/mcf (36%) in the First Quarter of 2009 as compared to the same period in the prior year, reflecting the $2.98/mcf (38%) decrease in the AECO daily price.

Sales Volumes

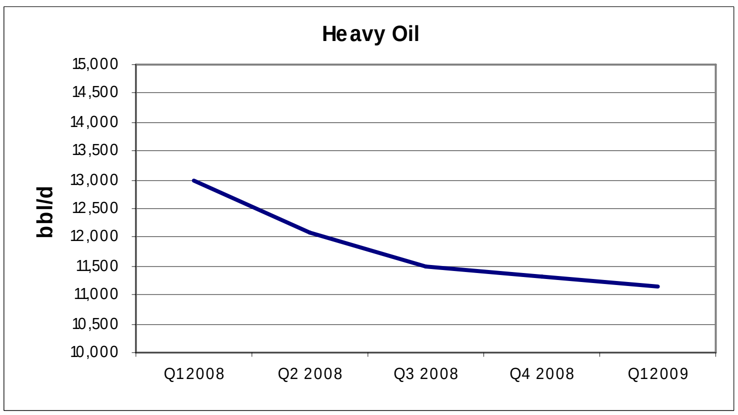
The average daily sales volumes by product were as follows:

	Three Months Ended March 31				
	2009		2008		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)(1)	**24,233**	**45%**	25,509	44%	(5%)
Heavy oil (bbl/d)	**11,141**	**21%**	12,980	22%	(14%)
Natural gas liquids (bbl/d)	**2,837**	**5%**	2,484	4%	14%
Total liquids (bbl/d)	**38,211**	**71%**	40,973	70%	(7%)
Natural gas (mcf/d)	**95,421**	**29%**	102,570	30%	(7%)
Total oil equivalent (boe/d)	**54,115**	**100%**	58,067	100%	(7%)

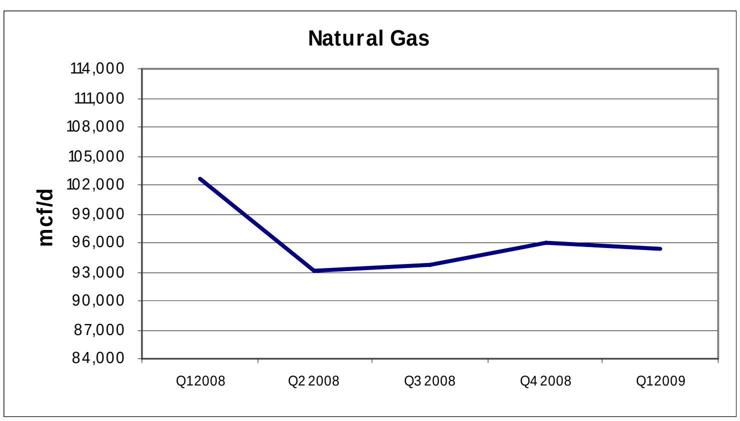
(1) Harvest classifies our oil production, except that produced from Hay River, as light to medium and heavy according to NI 51-101 guidance. The oil produced from Hay River has an average API of 24° (medium grade) and is classified as a light to medium oil, notwithstanding that, it benefits from a heavy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



During the First Quarter of 2009, Harvest's average daily production of light/medium oil was 24,233 bbl/d, a 1,276 bbl/d or 5% reduction from the First Quarter of 2008 and an 855 bbl/d decrease or 3% from the Fourth Quarter of 2008. The decrease in production in the First Quarter of 2009 relative to the Fourth Quarter of 2008 is mainly attributed to increased downtime due to cold weather in January coupled with downtime at Hay River, our largest production area, due to temporary power outages. Compared to the First Quarter of 2008, the decrease in light/medium oil production is due to increased water cuts and normal decline partially offset by new wells drilled and the production from the acquisitions completed during the Third Quarter of 2008 as well as the items noted above.



During the First Quarter of 2009, our heavy oil production averaged 11,141 bbls/d, a 1,839 bbl/d or 14% decrease from the First Quarter of 2008 and a 165 bbl/d or 1% decrease from the Fourth Quarter of 2008. While our production in the First Quarter of 2009 remained constant with the Fourth Quarter of 2008, the reduction from the First Quarter of 2008 is largely the result of normal decline, increased water cuts on our larger producing wells in the west central Saskatchewan and Lloydminster areas, and reduced spending on our heavy oil properties in late 2008.



Natural gas production averaged 95,421 mcf/d in the First Quarter of 2009, a 7,149 mcf/d or 7% reduction from the First Quarter of 2008 and a 658 mcf/d or 1% decrease from the Fourth Quarter of 2008. Production in the First Quarter of 2009 remained relatively consistent with the Fourth Quarter of 2008 as the incremental production from the 2009 winter drilling program was offset by cold weather related downtime. The decrease in production relative to the First Quarter of 2008 is mainly due to natural declines offset by the acquisitions completed in the Third Quarter of 2008 and improved run time on our largest producing wells as well as the items noted above.

Revenues

	Three Months Ended March 31		
(000s)			
Light to medium oil sales	**$ 89,405**	$ 200,875	(55%)
Heavy oil sales	**37,255**	81,552	(54%)
Natural gas sales	**45,735**	77,270	(41%)
Natural gas liquids sales and other	**10,525**	17,636	(40%)
Total sales revenue	**182,920**	377,333	(52%)
Royalties	**(24,529)**	(62,400)	(61%)
Net Revenues	**$ 158,391**	$ 314,933	(50%)

Our revenue is impacted by changes to production volumes, commodity prices and currency exchange rates. Our total sales revenue for the three months ended March 31, 2009 of $182.9 million is $194.4 million lower than the same period of the prior year, of which $166.1 million is attributed to lower realized prices and $28.3 million is attributed to lower production volumes. The price decrease reflects the 49% decrease in Edmonton Par pricing and the 38% decrease in AECO daily natural gas pricing in the First Quarter of 2009 as compared to the First Quarter of 2008, while our decreased production volumes are attributed to natural decline rates and reduced spending. Our revenues were also impacted by the decrease in the Canadian dollar, which resulted in a favourable variance of approximately $35.3 million.

As discussed earlier, light to medium oil sales revenue for the First Quarter of 2009 was $111.5 million lower than the comparative period due to a $99.3 million unfavourable price variance and a $12.2 million unfavourable volume variance. Heavy oil sales revenue of $37.3 million in the First Quarter of 2009 was $44.3 million lower than in the same period of the prior year due to a $32.0 million unfavourable price variance and a $12.3 million unfavourable volume variance. Natural gas sales revenue decreased by $31.5 million in the First Quarter of 2009 as compared to the First Quarter of 2008 due to a $25.3 million unfavourable price variance and a $6.2 million unfavourable volume variance.

During the First Quarter of 2009, natural gas liquids and other sales revenue decreased by $7.1 million compared to the same period in the prior year resulting from a $9.4 million unfavourable price variance offset by a $2.3 million favourable volume variance. Generally, the natural gas liquids volume variance will be aligned with our production of natural gas while the price variances will be aligned with the prices realized for our oil production. The positive volume variance is attributed to a few natural gas wells drilled in 2008 and the First Quarter of 2009 which yielded significant natural gas liquids.

Royalties

We pay Crown, freehold and overriding royalties to the owners of mineral rights from which production is generated. These royalties vary for each property and product and our Crown royalties are based on a sliding scale dependent on production volumes and commodity prices.

Throughout the First Quarter of 2009, net royalties as a percentage of gross revenue were 13.4% (2008 – 16.5%) and aggregated to $24.5 million (2008 - $62.4 million). The decrease in our royalty rate quarter over quarter is due to reduced royalty rates in a lower commodity price environment and the Government of Alberta's New Royalty Framework.

Operating Expenses

(000s except per boe amounts)	Three Months Ended March 31 2009 Total		2009 Per BOE		2008 Total		2008 Per BOE	Per BOE Change
Operating expense								
Power and fuel	**$**	**18,028**	**$**	**3.70**	$	18,500	$ 3.50	6%
Well Servicing		**12,629**		**2.59**		10,523	1.99	30%
Repairs and maintenance		**11,820**		**2.43**		10,981	2.08	17%
Lease rentals and property taxes		**7,598**		**1.56**		7,505	1.42	10%
Processing and other fees		**5,031**		**1.03**		2,074	0.39	164%
Labour – internal		**6,262**		**1.29**		6,322	1.20	8%
Labour – contract		**3,786**		**0.78**		3,901	0.74	5%
Chemicals		**3,876**		**0.80**		3,842	0.73	10%
Trucking		**3,130**		**0.64**		2,797	0.53	21%
Other		**3,175**		**0.65**		5,878	1.11	(41%)
Total operating expense	**$**	**75,335**	**$**	**15.47**	$	72,323	$ 13.69	13%
Transportation and marketing expense	**$**	**2,932**	**$**	**0.60**	$	3,025	$ 0.57	5%

First Quarter 2009 operating costs totaled $75.3 million, an increase of $3.0 million as compared to the same period in the prior year. On a per barrel basis, operating costs have increased to $15.47/boe in the first three months of 2009 as compared to $13.69/boe during the same period in the prior year, a 13% increase substantially attributed to reduced production volumes and increased well servicing and repair and maintenance activity.

Power and fuel costs, comprised primarily of electric power costs, represented approximately 24% of our total operating costs during the First Quarter of 2009. The average Alberta electric power price of $63.01/MWh in the First Quarter of 2009 was 18% lower than the First Quarter 2008 average price of $76.69/MWh. However, the decrease is not fully reflected in our First Quarter 2009 power and fuel costs due to increased power consumption at Hay River as we began purchasing power from BC Hydro late in the First Quarter of 2008 coupled with cold weather in January, when the average Alberta power price was $92.97/MWh. During the First Quarter of 2009, Harvest electricity usage in Alberta was exposed to market prices, while during the First Quarter of 2008, to mitigate our exposure to electric power price fluctuations, we had electric power price risk management contracts in place which resulted in a gain of $1.5 million. Beginning in April 2009, we have electric power price risk management contracts on 10 MWh at an average price of $61.90 per MWh through December 2009. The following table details the electric power costs per boe before and after the impact of our price risk management program.

(per boe)	Three Months Ended March 31 2009	2008	Change
Electric power and fuel costs	**$ 3.70**	$ 3.50	6%
Realized gains on electricity risk management contracts	**-**	(0.29)	(100%)
Net electric power and fuel costs	**$ 3.70**	$ 3.21	15%
Alberta Power Pool electricity price (per MWh)	**$ 63.01**	$ 76.69	(18%)

First Quarter 2009 transportation and marketing expense remained relatively unchanged at $2.9 million ($0.60 per boe) as compared to $3.0 million ($0.57 per boe) in the First Quarter of 2008. These costs relate primarily to delivery of natural gas to Alberta's natural gas sales hub, the AECO Storage Hub, and to a lesser extent, our costs of trucking clean crude oil to pipeline receipt points. As a result, the total dollar amount of costs fluctuates in relation with our natural gas production volumes while the cost per boe typically remains relatively constant.

Operating Netback

	Three Months Ended March 31	
(per boe)	**2009**	2008
Revenues	**$ 37.56**	$ 71.41
Royalties	**(5.04)**	(11.81)
Operating expense	**(15.47)**	(13.69)
Transportation and marketing expense	**(0.60)**	(0.57)
Operating netback[1]	**$ 16.45**	$ 45.34

[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 the First Quarter of 2009, our operating netback decreased by $28.89/boe or 64% over the same period in the prior year. The decrease in our operating netback is primarily attributed to a $33.85/boe decrease in realized commodity prices, reflecting the decrease in Edmonton Par, Bow River and AECO pricing over the prior year, offset by a decrease in royalties of $6.77/boe resulting from lower realized prices.

General and Administrative ("G&A") Expense

	Three Months Ended March 31		
(000s except per boe)			
Cash G&A	**$ 8,653**	$ 8,469	2%
Unit based compensation (recovery) expense	**(1,259)**	3,440	(137%)
Total G&A	**$ 7,394**	$ 11,909	(38%)
Cash G&A per boe	**$ 1.78**	$ 1.60	11%

For the three months ended March 31, 2009, Cash G&A costs remained relatively consistent with the same period in the prior year, as cost reduction efforts made in the First Quarter of 2009 are not expected to be fully realized until the Second Quarter. Generally, approximately 75% of our Cash G&A expenses are related to salaries and other employee related costs.

Our unit based compensation plans provide employees with the option of settling outstanding awards with cash. As a result, unit based compensation expense is determined using the intrinsic method, being the difference between the Trust Unit trading price and the strike price of the unit awards adjusted for the proportion that is vested. Total unit based compensation expense decreased $4.7 million in the First Quarter of 2009 as compared to the First Quarter of 2008 as the market price of our Trust Units dropped in 2009, while appreciating in 2008.

Depletion, Depreciation, Amortization and Accretion Expense

	Three Months Ended March 31		
(000s except per boe)	**2009**	2008	Change
Depletion, depreciation and amortization	**$ 106,209**	$ 106,204	-%
Depletion of capitalized asset retirement costs	**4,748**	3,624	31%
Accretion on asset retirement obligation	**6,055**	4,597	32%
Total depletion, depreciation, amortization and accretion	**$ 117,012**	$ 114,425	2%
Per boe	**$ 24.03**	$ 21.65	11%

Our overall depletion, depreciation, amortization and accretion ("DDA&A") expense for the three months ended March 31, 2009 was $2.6 million higher compared to the same period in the prior year. The increase is attributed to increased accretion expense due to an increase in the asset retirement obligation balance quarter over quarter and slightly higher finding, development and acquisition costs that have increased our depletion rate offset by lower production volumes.

Capital Expenditures

	Three Months Ended March 31	
(000s)	**2009**	2008
Land and undeveloped lease rentals	**$ 834**	$ 985
Geological and geophysical	**1,015**	3,136
Drilling and completion	**60,022**	56,376
Well equipment, pipelines and facilities	**43,810**	16,408
Capitalized G&A expenses	**2,762**	2,666
Furniture, leaseholds and office equipment	**267**	-
Development capital expenditures excluding acquisitions and non-cash items	**108,710**	79,571
Non-cash capital (recoveries) additions	**(302)**	543
Total development capital expenditures excluding acquisitions	**$ 108,408**	$ 80,114

The focus of our activity in the First Quarter of 2009 was our Hay River project in northeast British Columbia where we incurred approximately 60% of our capital spending for the quarter. Hay River is a winter access only property requiring that all heavy equipment, such as drilling rigs, only operate from December to March. During the quarter we drilled 43 wells including 20 multi-leg horizontal producers, 18 horizontal injection wells, 4 water source wells and 1 stratigraphic test well in this area. During 2008, the benefit of our enhanced water injection in Hay River was very evident as we were able to maintain our production throughout the year without the benefit of a large drilling program. As part of our 2009 Hay River drilling program, we are further enhancing our water injection capability, particularly in our newly developed area with additional horizontal injection wells and water source wells. A stratigraphic test well confirmed a pool extension identified seismically which we expect will increase both our original oil in place as well as our inventory of drillable locations. Our program was completed by the end of the quarter and we have been ramping up production with volumes reaching 7,000 boe/d early in the Second Quarter.

Drilling activity in our other areas was modest given the continuing softness in commodity prices. At Suffield, we drilled a horizontal water injection well into our North Batus pool to initiate the second phase of our enhanced water injection project initiated last year. At Chedderville, we drilled 3 additional wells into our Ostracod pool discovery as we continue to develop and delineate this liquids rich gas channel sand. We also participated in a shallow gas drilling program at Channel Lake where we drilled 22 gross (11 net) wells.

In addition to activity at our Suffield Enhanced Oil Recovery ("EOR") project as noted above, at Bellshill Lake, our enhanced waterflood project is showing early signs of response and we expect production to increase over the course of the Second and Third Quarter. Polymer injection at our Wainwright EOR project will commence early in the Second Quarter and we are actively evaluating additional opportunities to apply our EOR technologies.

The following summarizes Harvest's participation in gross and net wells drilled during the first three months of 2009:

	Total Wells		Successful Wells		Abandoned Wells	
Area	**Gross(1)**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Hay River	43.0	43.0	43.0	43.0	-	-
Southeast Saskatchewan	2.0	2.0	2.0	2.0	-	-
Southeast Alberta	25.0	11.5	25.0	11.5	-	-
Red Earth	1.0	1.0	1.0	1.0	-	-
Suffield	1.0	1.0	1.0	1.0	-	-
Lloydminster/Hayter	-	-	-	-	-	-
Rimbey	9.0	2.6	9.0	2.6	-	-
Markerville	-	-	-	-	-	-
Northwest Alberta	-	-	-	-	-	-
Other Areas	1.0	1.0	1.0	1.0	-	-
Total	82.0	62.1	82.0	62.1	-	-

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

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 $3.0 million during the first three months of 2009 as a result of accretion expense of $6.1 million, new liabilities recorded of $0.4 million, offset by $3.5 million of asset retirement expenditures.

DOWNSTREAM OPERATIONS

First Quarter Highlights

- First Quarter of 2009 cash from downstream operations totaled $142.0 million (2008 - $24.5 million) primarily attributed to improved refining margins, a gain from operationally hedging our feedstock costs, a significant weakening of the Canadian dollar and lower costs for purchased energy.
- During the First Quarter of 2009, downstream refining margins averaged US$15.18/bbl reflecting a US$6.28/bbl increase over the prior year reflecting higher margins on high sulphur fuel oil ("HSFO") and gasoline products coupled with increased discounts on feedstock, partially offset by reduced margins on distillate products, all relative to the WTI benchmark price.
- During the First Quarter of 2009, the operational hedging of the WTI component of our feedstock costs through the Supply and Offtake Agreement resulted in a US$45.0 million reduction in our feedstock costs.
- Weakening of the Canadian dollar relative to the U.S. dollar in the First Quarter of 2009 as compared to the First Quarter of 2008, added $34.2 million to our gross margin in 2009 as our U.S. dollar denominated margins are translated to Canadian dollars.
- Refinery throughput averaged 104,296 bbls/d representing a 91% utilization rate and reflecting the deterioration of the hydrocracker catalyst, which was replaced during the Second Quarter scheduled turnaround, and other end of run conditions.
- Refining operating costs remained relatively constant at $2.05/bbl of throughput as compared to $2.10/bbl in the prior year reflecting continued cost containment efforts offset by decreased throughput.
- Cost of purchased energy decreased to $1.77/bbl of throughput as compared to $4.23/bbl in the prior year reflecting a weaker commodity price environment during the First Quarter of 2009.

Summary of Financial and Operational Results

(in $000's except where noted below)	Three Months Ended March 31		
	2009	2008	Change
Revenues	**572,704**	1,062,419	(46%)
Purchased feedstock for processing and products purchased for resale	**381,837**	959,992	(60%)
Gross margin[(1)]	**190,867**	102,427	86%
Costs and expenses			
Operating expense	**23,965**	25,895	(7%)
Purchased energy expense	**16,607**	43,127	(61%)
Turnaround and catalyst expense	**4,202**	-	100%
Marketing expense	**2,979**	8,597	(65%)
General and administrative expense	**355**	568	(38%)
Depreciation and amortization expense	**22,184**	16,500	34%
Earnings From Operations[(1)]	**120,575**	7,740	1,458%
Cash capital expenditures	**6,904**	6,027	15%
Feedstock volume (bbl/day)[(2)]	**104,296**	111,999	(7%)
Yield (000's barrels)			
Gasoline and related products	**3,321**	3,417	(3%)
Ultra low sulphur diesel and jet fuel	**3,494**	4,261	(18%)
High sulphur fuel oil	**2,370**	2,566	(8%)
Total	**9,185**	10,244	(10%)
Average refining margin (US$/bbl)[(3)]	**15.18**	8.90	71%

(1) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.
(2) Barrels per day are calculated using total barrels of crude oil feedstock and vacuum gas oil.
(3) Average refining margin is calculated based on per barrel of feedstock throughput.

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:

	Three Months Ended March 31		
	2009	2008	Change
WTI crude oil (US$/bbl)	**43.08**	97.90	(56%)
Brent crude oil (US$/bbl)	**45.67**	93.39	(51%)
Basrah Official Sales Price Discount (US$/bbl)	**(3.75)**	(7.78)	(52%)
RBOB gasoline (US$/bbl/gallon)	**52.13/1.24**	104.36/2.48	(50%)
Heating Oil (US$/bbl/gallon)	**56.46/1.34**	115.10/2.74	(51%)
High Sulphur Fuel Oil (US$/bbl)	**36.99**	70.43	(47%)
Canadian / U.S. dollar exchange rate	**0.804**	0.996	(19%)

During the First Quarter of 2009, the Heating Oil Crack Spread averaged US$13.38/bbl, a decrease of US$3.82/bbl over the US$17.20/bbl averaged in the prior year, due to decreased demand as global economic growth slowed. The RBOB

Gasoline Crack Spread averaged US$9.05/bbl in the First Quarter of 2009, an increase of US$2.59/bbl from the US$6.46/bbl in the prior year, as refinery output decreased to balance the weak demand environment, which resulted in the improvement in gasoline margins. Similarly, the HSFO price averaged US$6.09/bbl less than WTI in the First Quarter of 2009, an improvement of US$21.38/bbl from the average of US$27.47/bbl less than WTI in the prior year.

During the First Quarter of 2009, the Canadian/U.S. dollar exchange rate averaged 0.804 as compared to 0.996 in the First Quarter of the prior year. As compared to the First Quarter of 2008, the weakening of the Canadian dollar in 2009 has significantly improved the contribution from our downstream operations as substantially all of its gross margin, cost of purchased energy and marketing expense are denominated in U.S. dollars. The net impact of a weakening Canadian dollar increased our refining gross margin by $34.2 million in the quarter.

Summary of Gross Margin

The following table summarizes our downstream gross margin for the three months ended March 31, 2009 and 2008 segregated between refining activities and petroleum marketing and other related businesses.

	Three Months Ended March 31					
	2009			2008		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Sales revenue[1]	**550,214**	**100,675**	**572,704**	1,036,631	144,006	1,062,419
Cost of feedstock for processing and	**372,983**	**87,039**	**381,837**			
Gross margin[2]	**177,231**	**13,636**	**190,867**	91,032	11,395	102,427
Average refining margin (US$/bbl)	**15.18**			8.90		

(1) Downstream sales revenue and cost of products for processing and resale are net of intra-segment sales of $78.2 million for the three months ended March 31, 2009 (2008 - $118.2 million) reflecting the refined products produced by the refinery and sold by the Marketing Division.

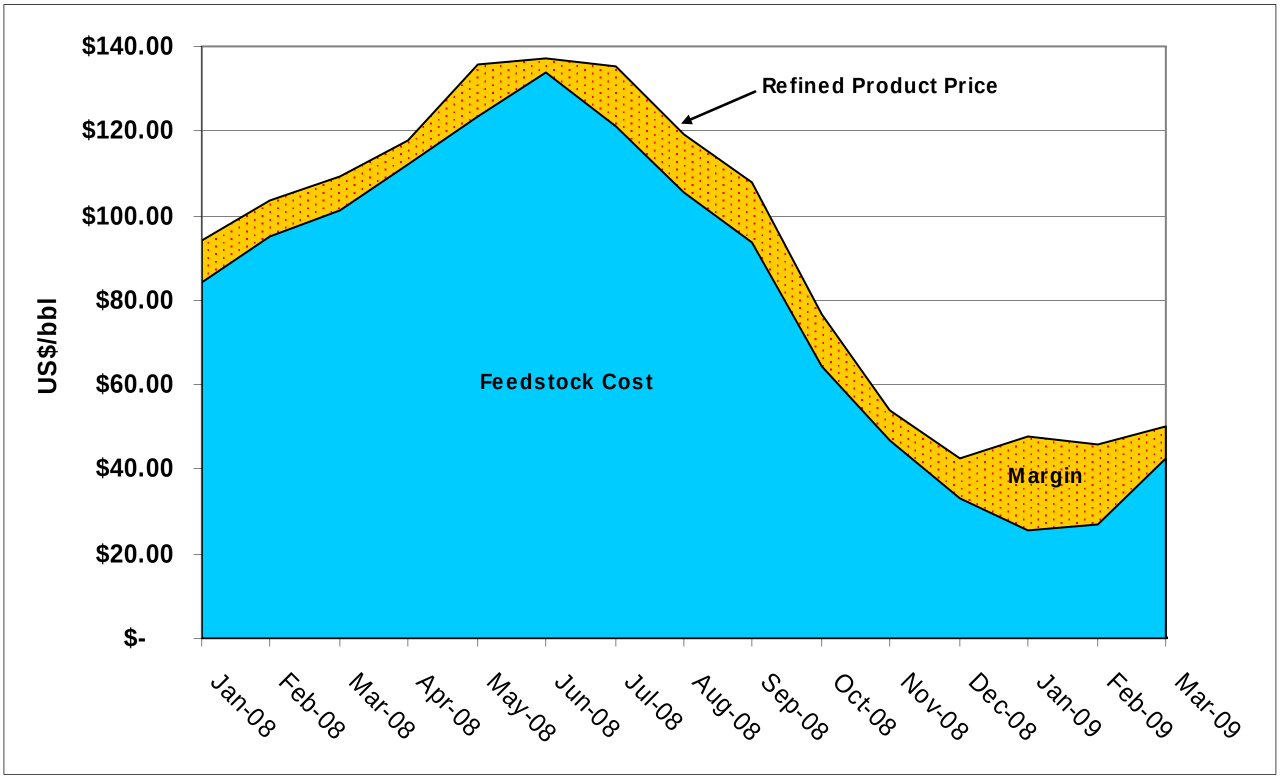
(2) This is a non-GAAP measure; please refer to "Non-GAAP Measures" in this MD&A.

For the three months ended March 31, 2009, our refining gross margin was $177.2 million as compared to $91.0 million in the prior year, an increase of $86.2 million. The increase in refining gross margin is primarily due to a US$21.38/bbl improvement in the HSFO benchmark crack spread, a US$2.59/bbl improvement in the RBOB gasoline benchmark crack spread, a US$45.0 million operational hedging gain on our feedstock purchases, a US$6.64/bbl improved feedstock discount, and the translation of our U.S. dollar denominated gross margin to Canadian dollars resulted in an increase to gross margin of $34.2 million. These factors were partially offset by a US$3.82/bbl decrease in the Heating Oil benchmark crack spread.

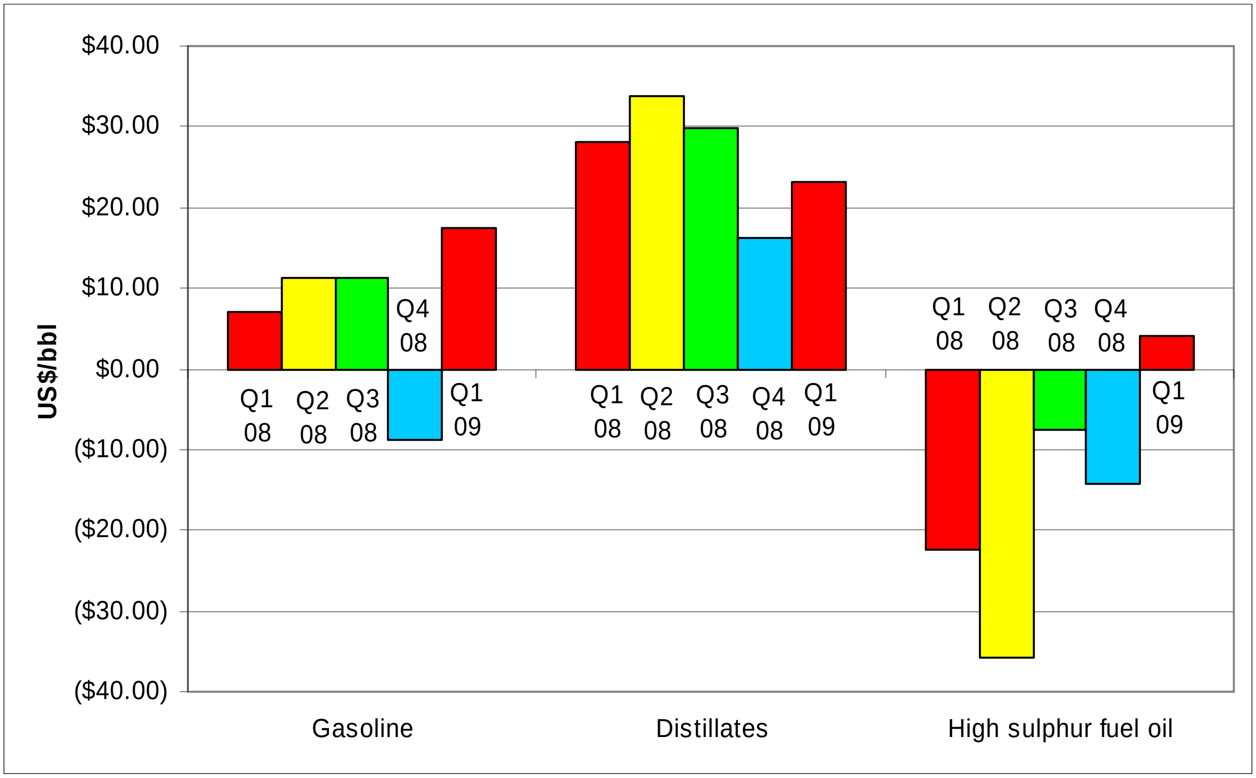
For the three months ended March 31, 2009, our marketing division earned a gross margin of $13.6 million as compared to $11.4 million in the prior year, an increase of 20%, primarily due to improved margins on home heating fuels and increased volumes and margins of wholesale products.

Refining Gross Margin

We analyze our refining margin on each refined product and our sales revenue relative to benchmark prices for the refined product and the WTI benchmark price. With respect to feedstock costs, we analyze our price discounts relative to the WTI benchmark price and segregate crude oil sources by country of origin. The following graph summarizes our average refining margin relative to the cost of feedstock for the period of January 2008 to March 2009:



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



Refining margins on HSFO improved significantly in the First Quarter of 2009 relative to the Fourth Quarter and the First Quarter of 2008, due to improved margins on lower valued petroleum products. Gasoline margins also improved in the First Quarter of 2009 as compared to the Fourth Quarter of 2008, when gasoline margins were particularly depressed, and the First Quarter of 2008. Margins on distillate products improved in the First Quarter of 2009 over the Fourth Quarter of 2008, but were lower than the First Quarter of 2008.

Refinery Sales Revenue

Our refinery sales revenue is dependent on the selling price as well as the yield of refined products produced from the crude oil and other feedstocks. Although our yield can be altered slightly by adjusting refinery operations to react to market conditions and seasonal demand, product yields are primarily impacted by the type of crude oil feedstock processed and refinery performance. A comparison of our refinery yield, product pricing and revenue for the three months ended March 31, 2009 and 2008 is presented below:

	Three Months Ended March 31					
	2009			2008		
	Refinery Revenues	**Volume**	**Sales Price**[1]	Refinery Revenues	Volume	Sales Price[1]
	(000's of Cdn$)	(000s of bbls)	(US$ per bbl/ US$ per US gal)	(000's of Cdn$)	(000s of bbls)	(US$ per bbl/ US$ per US gal)
Gasoline products	**214,471**	**3,492**	**49.38/1.18**	355,564	3,528	100.38/2.39
Distillates	**224,454**	**3,273**	**55.14/1.31**	512,586	4,216	121.09/2.88
High sulphur fuel oil	**111,289**	**2,473**	**36.18**	168,481	2,362	71.04
	550,214	**9,238**	**47.89**	1,036,631	10,106	102.17
Inventory adjustment		**(53)**			138	
Total production		**9,185**			10,244	
Yield (as a % of Feedstock) [2]		**98%**			101%	

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

[2] After adjusting for changes in inventory held for resale.

For the three months ended March 31, 2009, our refinery yield was comprised of 36% gasoline products, 38% distillates and 26% HSFO compared to 33%, 42% and 25% for the same products respectively during 2008. The shift in product yield in 2009 from distillates to gasoline is primarily attributed to end of run activity of the hydrocracker catalyst as well as other end of run conditions and a different feedstock mix.

In the First Quarter of 2009, our average sales price was US$47.89/bbl (a premium of US$4.81/bbl over WTI) as compared to an average selling price of US$102.17/bbl in the prior year (a premium of US$4.27/bbl over WTI). This increase in premium relative to WTI of US$0.54/bbl represents a $6.2 million favourable price variance in the current period.

During the First Quarter of 2009, the average sales price of our gasoline products of US$49.38/bbl was a US$6.30/bbl premium to the average WTI price as compared to a US$2.48/bbl premium over WTI realized in the same period of the prior year representing a $16.6 million increase in gross margin. This US$3.82/bbl increase in our gasoline refining margin relative to WTI reflects the US$2.59/bbl increase in the RBOB gasoline benchmark crack spread.

During the First Quarter of 2009, the average sales price for our distillate products of US$55.14/bbl was a US$12.06/bbl premium over the average WTI price as compared to a US$23.19/bbl premium over WTI realized in the same period of the prior year representing a $45.3 million drop in gross margin. The US$11.13/bbl decrease in our distillate refining margin relative to WTI was more than the US$3.82/bbl decrease in the Heating Oil benchmark crack spread due to the decrease in the crack spreads on jet fuel and ultra low sulphur diesel decreasing by more than the benchmark Heating Oil crack spread.

During the First Quarter of 2009, the average sales price of our HSFO of US$36.18/bbl was a US$6.90/bbl discount to the average WTI price as compared to a US$26.86/bbl discount in the same period of the prior year representing a $61.4

million increase in gross margin. The US$19.96/bbl improvement in our HSFO refining margin relative to WTI reflects the US$21.38/bbl increase in the HSFO benchmark crack spread.

Refinery Feedstock

The volatility of WTI prices from month to month makes it difficult to compare the financial impact of specific crude types when our consumption of crude types varies from month to month and costs are aggregated over the quarter. Further, our refinery competes for international waterborne crude oil and VGO and the WTI benchmark price generally reflects a land-locked North American price with limited access to the international markets.

Changes to the cost of our feedstock reflect numerous factors beyond changes in WTI price, including the quality of the crude oil processed, the mix of crude oil types, the costs of transporting the crude oil to our refinery, the operational hedging of the WTI component of our feedstock costs through the Supply and Offtake Agreement, the ten day delay in pricing pursuant to the Supply and Offtake Agreement and for Iraqi crude oil purchased, the Official Selling Price ("OSP") as set by the Oil Marketing Company of the Republic of Iraq. The discount of Iraqi crude oil relative to the WTI benchmark price is influenced by the quality of the crude oil as well as by the demand from other purchasers who may not be based in North America. On a monthly basis, the OSP discount is announced as a discount to the WTI benchmark price for North American deliveries and can fluctuate significantly.

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

	Three Months Ended March 31					
	2009			2008		
	Cost of Feedstock	**Volume**	**Cost per Barrel** (1)	Cost of Feedstock	Volume	Cost per Barrel (1)
	(000's of Cdn$)	(000s of bbls)	(US$/bbl)	(000's of Cdn$)	(000s of bbls)	(US$/bbl)
Iraqi	**292,341**	**7,023**	**33.47**	539,885	5,903	91.09
Russian	**15,139**	**225**	**54.10**	195,168	2,010	96.71
Venezuelan	**51,521**	**1,735**	**23.87**	140,944	1,507	93.15
Crude Oil Feedstock	**359,001**	**8,983**	**32.13**	875,997	9,420	92.62
Vacuum Gas Oil	**14,314**	**403**	**28.56**	80,077	771	103.45
	373,315	**9,386**	**31.98**	956,074	10,191	93.44
Net inventory adjustment (2)	**(4,817)**			(14,857)		
Additives and blendstocks	**7,417**			4,382		
Inventory write-down (recovery)	**(2,932)**			-		
	372,983			945,599		

(1) Cost of feedstock includes all costs of transporting the crude oil to the 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.

During the First Quarter of 2009, throughput was limited due to end of run activity of the catalyst in our hydrocracker unit and other end of run conditions, which reduced feedstock volume to an average of 104,296 bbl/d, a decrease of 7,703 bbl/d from 111,999 bbl/d in the First Quarter of 2008 and 10,704 bbl/d lower than the refinery's nameplate capacity of 115,000 bbl/d.

As is normal business practice, the WTI component of our feedstock cost is operationally hedged under the Supply and Offtake Agreement. When we commit to crude oil purchases, Vitol sells a forward WTI price contract for the next contract month, which results in price fluctuations on our purchase commitment being offset by the price volatility of the forward price curve. If the timing between processing the crude oil and the expiration of the forward contract are not aligned, the volume of unprocessed crude oil relating to that forward contract is rolled to the next 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 resulted in accumulated gains from the rolling forward of these operational hedges, which under the terms of the Supply and Offtake Agreement reduce our feedstock costs in the month the feedstock is processed. During the First Quarter of 2009, this operational hedging resulted in a US$45.0 million reduction to the cost of our feedstock, as compared to the same period in the prior year when this operational hedging resulted in a $7.4 million increase in the cost of our feedstock. The Supply and Offtake Agreement is more fully described in our Annual Information Form for the year ended December 31, 2008 filed on SEDAR at www.sedar.com.

The cost of our crude oil feedstock averaged US$32.13/bbl during the First Quarter of 2009 representing a US$10.95/bbl discount from WTI as compared to a cost of US$92.62/bbl and a discount of US$5.28/bbl in the First Quarter of the prior year. The US$10.95/bbl discount is comprised of a US$7.30/bbl quality discount (2008 – US$6.99/bbl), plus a US$4.70/bbl operational hedging gain (2008 – charge of US$0.72/bbl), offset by a US$1.05/bbl charge relating to the timing under the Supply and Offtake Agreement with Vitol (2008 – US$0.98).

The average cost of purchased VGO during the First Quarter of 2009 was US$28.56/bbl representing a discount of US$14.52/bbl relative to the WTI benchmark price as compared to US$103.45/bbl and a US$5.55/bbl premium in the First Quarter of the prior year. The US$14.52/bbl discount is comprised of a US$6.64/bbl discount to WTI (2008 – a premium of US$3.72/bbl), a US$6.93/bbl operational hedging gain (2008 – charge of US$0.77/bbl), and a US$0.95/bbl reduction relating to the Supply and Offtake Agreement with Vitol (2008 – charge of US$1.06/bbl). The discount in the First Quarter of 2009 is attributed to supply and demand disruptions in the very tightly balanced VGO market coupled with the benefit of our operational hedging.

Operating Expenses

The following summarizes the operating costs from the refinery and marketing division for the three months ended March 31, 2009 and 2008:

	Three Months Ended March 31					
	2009			2008		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Operating expense	**19,214**	**4,751**	**23,965**	21,375	4,520	25,895
Turnaround and catalyst	**4,202**	**-**	**4,202**	-	-	-
Purchased energy	**16,607**	**-**	**16,607**	43,127	-	43,127
	40,023	**4,751**	**44,774**	64,502	4,520	69,022

The largest component of refining operating expense is wages, salaries and benefits which totaled $12.3 million during the First Quarter of 2009 (2008 - $13.2 million) while the other significant components were maintenance and repair costs of $2.6 million (2008 - $4.1 million), insurance of $1.6 million (2008 - $1.4 million) and professional services of

$0.6 million (2008 - $1.0 million). During the three months ended March 31, 2009, refining operating expenses were $2.05/bbl as compared to $2.10/bbl in the three months ended March 31, 2008 reflecting a reduction in total refining operating expenses partially offset by decreased throughput. During the three month period ended March 31, 2009, the marketing division's operating expenses remained consistent at approximately $4.8 million.

Turnaround and catalyst expenditures for the three months ended March 31, 2009 of $4.2 million (2008 - nil) relate to costs incurred in preparation for the scheduled turnaround in the Second Quarter of 2009.

Purchased energy, consisting of low sulphur fuel oil and electricity, is required to provide heat and power to refinery operations. Our purchased energy for the three months ended March 31, 2009 was $1.77/bbl of throughput as compared to $4.23/bbl for the three months ended March 31, 2008. In the First Quarter of 2009, we purchased approximately 336,000 barrels of fuel oil at an average price of US$33.91/bbl as compared to approximately 498,000 barrels purchased in the First Quarter of 2008 at an average price of US$80.94/bbl. The $26.3 million decrease in the cost of purchased fuel oil is due to a $13.1 million decreased price variance and a $13.2 million decrease in purchased volumes as we consumed more internally generated fuel and in total required less fuel oil to run the refinery as the hydrocracker unit had reduced throughput due to end of run activity of the catalyst. Our electricity costs remained substantially unchanged during the year at $2.4 million as compared to $2.6 million in the prior year.

Marketing Expense and Other

During the three months ended March 31, 2009, marketing expense was comprised of $1.0 million (2008 - $0.9 million) of marketing fees (based on US$0.08/bbl) to acquire feedstock and $2.0 million (2008 - $7.7 million) of "Time Value of Money" charges both pursuant to the terms of the Supply and Offtake Agreement. The decreased "Time Value of Money" charge is mainly the result of a lower LIBOR rate in the First Quarter of 2009 coupled with a lower crude oil inventory investment due to the lower commodity prices. As at March 31, 2009, Harvest had commitments totaling approximately $246.2 million in respect of future crude oil feedstock purchases and related transportation from Vitol.

Capital Expenditures

Capital spending for the three months ended March 31, 2009 totaled $6.9 million (2008 - $6.0 million) relating to various capital improvement projects.

Depreciation and Amortization Expense

The following summarizes the depreciation and amortization expense for the three months ended March 31, 2009 and 2008:

	Three Months Ended March 31					
	2009			2008		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Tangible assets	**19,546**	**892**	**20,438**	14,479	553	15,032
Intangible assets	**1,384**	**362**	**1,746**	1,118	350	1,468
	20,930	**1,254**	**22,184**	15,597	903	16,500

The process units are amortized over an average useful life of 20 to 30 years. The intangible assets, consisting of engineering drawings, customer lists and fuel supply contracts, are amortized over a period of 20 years, 10 years and the term of the expected cash flows respectively.

Goodwill

As the downstream assets are held in a self-sustaining subsidiary with a US dollar functional currency, the value of the goodwill is adjusted at the end of each accounting period to reflect the current US dollar exchange rate. We assess goodwill for impairment annually, or more frequently if events or changes in circumstances warrant. There has been no charge for impairment to goodwill since the date of acquisition.

RISK MANAGEMENT, FINANCING AND OTHER

Cash Flow Risk Management

With respect to our cash flow risk management program, see "Cash Flow Risk Management" in our MD&A for the year ended December 31, 2008 filed on SEDAR at www.sedar.com. The details of our commodity price contracts outstanding at March 31, 2009 are included in the notes to our consolidated financial statements which are also filed on SEDAR at www.sedar.com.

During the First Quarter of 2009, the lower commodity price environment resulted in Harvest realizing gains of $25.5 million on our risk management contracts, while higher commodity prices experienced in the First Quarter of 2008 resulted in $36.3 million of realized losses on our risk management contracts. The table below provides a summary of the gains and losses realized on our price risk management contracts for the three months ended March 31, 2009 and 2008:

	Three Months Ended March 31		
(000s)			
Crude oil	**$ -**	$ (8,579)	(100%)
Refined product	**25,572**	(31,816)	(180%)
Natural gas	**(30)**	(101)	(70%)
Currency exchange rates	**-**	2,654	(100%)
Electric Power	**-**	1,548	(100%)
Total	**$ 25,542**	$ (36,294)	(170%)

During the First Quarter of 2009, Harvest did not have any crude oil, currency exchange rate, or electric power contracts in place, while in the First Quarter of 2008, losses on our crude oil contracts totaled $8.6 million, and gains on our currency exchange rates and electric power contracts totaled $2.7 million and $1.5 million, respectively. In respect of refined products, we have 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 half of 2009. In total, during the first three months of 2009, we realized gains on our refined product contracts totaling $25.6 million due to refined product prices in the First Quarter 2009 being below the floor prices on our contracts as compared to the same period in the prior year when we realized losses of $31.8 million due to the higher commodity price environment.

During the First Quarter of 2009, we entered into electricity price swap contracts for 10 MWh at $61.90 per MWh from April to December 2009 and U.S./Cdn currency exchange rate swaps for $15 million per month from July to December 2009 at an average exchange rate of US$0.78/Cdn$1.00.

As at March 31, 2009, the mark-to-market value on our refined product contracts was $23.6 million, while the mark-to-market value on our currency contracts, natural gas contracts and electric power contracts aggregated to $2.1 million.

Interest Expense

	Three Months Ended March 31		
	2009	2008	
Interest on short term debt			
Bank loan	**$ -**	$ -	n/a
Convertible Debentures	**60**	201	(70%)
Amortization of deferred finance charges – short term debt	**-**	-	n/a
	60	201	(70%)
Interest on long-term debt			
Bank loan	**6,251**	16,060	(61%)
Convertible Debentures	**19,113**	13,062	46%
7 7/8% Senior Notes	**6,553**	5,306	24%
Amortization of deferred finance charges – long term debt	**675**	675	-%
	32,592	35,103	(7%)
Total interest expense	**$ 32,652**	$ 35,304	(8%)

Interest expense for the three months ended March 31, 2009, including the amortization of related financing costs, decreased $2.7 million (8%) compared to the same period in the prior year as interest on our bank borrowings decreased by $9.8 million, while total interest expense on Convertible Debentures has increased as a result of our Second Quarter 2008 Convertible Debenture offering.

The interest on our $1.6 billion Extendible Revolving Credit Facility is at a floating rate based on 70 basis points over bankers' acceptances for Canadian dollar borrowings. During the three months ended March 31, 2009, interest charges on bank loans reflected an average interest rate of 2.01% compared to 4.83% in the same period in the prior year.

The interest on our Convertible Debentures totaled $19.2 million during the First Quarter 2009, representing a $5.9 million increase compared to the First Quarter 2008. The increase is due to the April 25th issuance of $250 million face value of 7.5% Convertible Debentures due 2015. Details on the Convertible Debentures outstanding are fully described in Note 12 to the audited consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com. Interest on the Convertible Debentures is based on the effective yield of the debt component of the Convertible Debentures, and as a result, the interest expense recorded is greater than the cash interest paid.

The interest on our 7 7/8% Senior Notes totaled $6.6 million for the three months ended March 31, 2009 which is an increase of $1.2 million over the same period in the prior year. The increase is due to the weakening of the Canadian dollar compared to the same period in the prior year, as the interest on these notes is denominated in U.S. dollars. Similar to our Convertible Debentures, interest expense is based on the effective yield, and as a result, the interest expense recorded is greater than the cash interest paid.

Included in short and long term interest expense is the amortization of the discount on the 7 7/8% Senior Notes, the accretion on the debt component balance of the Convertible Debentures to face value at maturity, as well as the amortization of commitment fees and legal costs incurred for our credit facility, all totaling $0.7 million for the three months ended March 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 $7^{7/8}$% Senior Notes as well as any other U.S. dollar cash balances. Realized foreign exchange losses of $0.5 million for the three months ended March 31, 2009, have resulted from the settlement of U.S. dollar denominated transactions. Since December 31, 2008, the Canadian dollar has weakened slightly resulting in an unrealized foreign exchange gain of $0.4 million for the First Quarter 2009.

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 the First Quarter of 2009, the weakening of the Canadian dollar relative to the U.S. dollar resulted in a $49.8 million net cumulative translation gain (2008 – $50.5 million) as the stronger U.S. dollar results in an increase in the relative value of the net assets in our downstream operations.

Future Income Tax

At the end of 2008, we had a net future income tax provision on our balance sheet totaling $204.0 million comprised of a $372.6 million provision for our mutual fund trust and other "flow through" entities and a net asset of $168.6 million for our corporate entities. For the three months ended March 31, 2009, we have recorded a future income tax expense of $2.0 million to reflect the changes in both the temporary differences held in our corporate entities and for changes in our forecasted temporary differences for our "flow through entities" as well as legislative tax rate changes both as of January 1, 2011. At March 31, 2009 we have a net future tax liability on our balance sheet totaling $206.0 million comprised of a $172.7 million net asset for our corporate entities offset by a $378.7 million provision for our mutual fund trust and other "flow through" entities. The future income tax asset recorded by our corporate entities will fluctuate during each accounting period to reflect changes in the respective temporary differences between the book value and tax basis of their assets as well as further legislative tax rate changes.

Currently, the principal source of our corporate entities' temporary differences is the difference between our net book value of our property, plant and equipment versus our unclaimed tax pools and the recognition for accounting purposes of a mark-to-market position on our risk management contracts.

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) and accordingly, the amount of this contingent liability has not been accrued at March 31, 2009. In addition to presenting the merit of our position to the CRA, we have filed a Notice of Objection with the CRA and are in the process of appealing directly to Tax Court.

Contractual Obligations and Commitments

We have contractual obligations and commitments entered into in the normal course of operations including the purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, and land lease obligations. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. We also have contractual obligations and commitments that are of a less routine nature as disclosed in the following table:

		Maturity			
Annual Contractual Obligations *(000s)*	**Total**	Less than 1year	1-3 years	4-5 years	After 5 years
Long-term debt(2)	**$ 1,549,168**	$ -	$ 1,549,168	$ -	$ -
Interest on long-term debt(4)	**81,180**	31,352	49,828	-	-
Interest on Convertible Debentures(3)	**309,705**	49,155	127,864	105,387	27,299
Operating and premise leases	**22,728**	5,935	13,337	2,890	566
Purchase commitments(5)	**39,535**	39,535	-	-	-
Asset retirement obligations(6)	**1,210,572**	10,748	30,790	26,958	1,142,076
Transportation (7)	**7,045**	2,675	3,630	740	-
Pension contributions(8)	**42,326**	5,700	14,217	14,791	7,618
Feedstock commitments	**246,159**	246,159	-	-	-
Total	**$ 3,508,418**	$ 391,259	$ 1,788,834	$ 150,766	$ 1,177,559

(1) As at March 31, 2009, we have entered into financial contracts for downstream production of refined products with average deliveries of approximately 20,000 bbl/d for the first half of 2009.
(2) Assumes that the outstanding Convertible Debentures either convert at the holders' option or are redeemed for Trust Units at our option.
(3) Assumes no conversions and redemption by Harvest for Trust Units at the end of the second redemption period.
(4) Assumes a constant foreign exchange rate.
(5) Relates to drilling commitments, AFE commitments and downstream purchase commitments.
(6) Represents the undiscounted obligation by period.
(7) Relates to firm transportation commitment on the Nova pipeline.
(8) Relates to the expected contributions for employee benefit plans.

We have a number of operating leases for moveable field equipment, vehicles and office space and our commitments under those leases are noted in our annual contractual obligations table above. The leases require periodic lease payments and are recorded as either operating costs or G&A. We also finance our annual insurance premiums, whereby a portion of the annual premium is deferred and paid monthly over the balance of the term.

Change In Accounting Policies

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 new standard contains additional guidance with respect to the recognition of intangible assets.

DISTRIBUTIONS TO UNITHOLDERS

Harvest is an integrated energy trust with a declining asset base in our upstream operations and a "near perpetual" asset in our downstream operations. The contribution from our upstream operations relies on successful exploitation of our existing reserves, future development activities and strategic acquisitions to replace existing production and add additional reserves as well as future petroleum and natural gas prices. With a prudent maintenance program, our downstream assets are expected to have a long life with additional growth in profitability available by upgrading the heavy fuel oil currently produced and/or expanding our refining capacity. Future development activities and modest acquisitions in our upstream business as well as the maintenance program in our downstream business will likely be funded by our cash generated from operating activities while we will generally rely on funding more significant acquisitions and growth initiatives from some combination of cash from operating activities, issuances of Trust Units and incremental debt. To the extent that we finance acquisitions and growth initiatives from cash from operating activities, distributions to Unitholders may be reduced. Should equity capital markets or incremental debt not be available to us, our ability to make the necessary expenditures to maintain or expand our assets may be impaired and result in reductions to future distributions paid to Unitholders.

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 a percentage of cash from operating activities for the three months ended March 31, 2009 and 2008:

	Three Months Ended March 31		
(000s except per trust unit amounts)	**2009**	2008	Change
Cash from Operating Activities	**$ 221,745**	$ 128,119	73%
Net Income (Loss)	**$ 56,864**	$ (346)	-%
Distributions declared	**$ 103,302**	$ 135,167	(24%)
Per trust unit	**$ 0.65**	$ 0.90	(28%)
Distribution reinvestment proceeds	**$ 30,038**	$ 35,890	(16%)
Distributions as a percentage of cash from operating activities	**47%**	106%	(59%)

LIQUIDITY AND CAPITAL RESOURCES

During the First Quarter of 2009, cash flow from operating activities was $221.7 million as compared to $128.1 million in the prior year. The First Quarter 2009 cash flow from operating activities includes a $15.3 million increase in non-cash working capital reflecting a $12.4 million decrease in accounts receivable and a $19.5 increase in payables offsetting a $21.4 build in downstream inventories. Cash flow from operating activities before changes in non-cash working capital totaled $206.4 million as compared to $183.1 million in the First Quarter of 2008 and $94.8 million in the Fourth Quarter of 2008. In the First Quarter of 2009, we declared distributions of $103.3 million ($73.3 million net of our distribution re-investment plans) and required $115.6 million for capital expenditures resulting in a net cash requirement of $17.5 million. At the end of the First Quarter of 2009, our bank borrowings totaled $1,233.8 million with $366.2 million of undrawn credit lines.

The following table summarizes our capital structure as at March 31, 2009 and December 31, 2008 as well as provides the key financial ratios contained in our Revolving Credit Facility. For a complete description of our Revolving Credit Facility, 7 7/8% Senior Notes and Convertible Debentures, see Notes 10, 11 and 12, respectively, to our audited consolidated financial statements for the year ended December 31, 2008 filed on SEDAR at www.sedar.com.

(in millions)

SUMMARY OF CAPITALIZATION	March 31, 2009	December 31, 2008
Revolving Credit Facility	**$1,233.8**	$1,226.2
7 7/8% Senior Notes Due 2011 (US$250 million)[1]	**315.3**	304.5
Convertible Debentures, at principal amount	**916.7**	916.7
Total Debt	**2,465.8**	2,447.4
Unitholders' Equity, at book value less equity component of convertible debentures		
161,508,947 issued at March 31, 2009	**2,592.9**	
157,200,701 issued at December 31, 2008		2,559.2
TOTAL CAPITALIZATION	**$5,058.7**	$5,006.6

FINANCIAL RATIOS		
Secured Debt to Annualized EBITDA[2]	1.5	1.5
Senior Debt to Annualized EBITDA[2]	1.8	1.8
Secured Debt to Total Capitalization	24%	25%
Senior Debt to Total Capitalization	31%	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.

During the First Quarter of 2009, the global economic slowdown continued as did the broadly based credit crunch which has been characterized as a universal reduction in the appetite for risk, a tightening of capital availability and a higher cost for renegotiated borrowings. There continues to be uncertainty over the ultimate depth of the economic slump as well as the timing and shape of the subsequent recovery. The current state of the credit markets can best be described as challenging and has resulted in our continuing to defer capital market initiatives, particularly the renewal of our credit facilities and further equity offerings, and as a result, our balance sheet leverage has not improved during the First Quarter of 2009. In light of this economic outlook, we have reduced our 2009 capital spending plan by approximately $100 million and reduced the staffing levels (including consultants) in our upstream operations by approximately 5% as well as reduced our distribution to Unitholders to $0.05 per Trust Unit monthly commencing in March 2009. In addition, we continue to pressure our suppliers to reduce their costs to reflect the current commodity price environment which should eventually result in lower operating and capital costs.

With respect to the renewal of our $1.6 billion Revolving Credit Facility which matures in April 2010, we have deferred requesting an extension as some lenders may have chosen to not extend and extending lenders would have likely required increased fees and credit spreads. Having recently provided our syndicate of lenders with our January 1, 2009 independent reserve reports, we are now engaged in discussions with our lead banks as to the potential size, pricing and terms for a new credit facility which will likely require a reserve based borrowing covenant and an amortization schedule for some portion of the lending commitments. We anticipate that by April 2010, borrowings under our credit facilities should approach $1 billion which may include approximately $100 million of proceeds from the disposition of non-core assets.

The most restrictive covenant of the $7^{7/8}$% Senior Notes limits the incurrence of additional indebtedness if such issuance would result in an interest coverage ratio, as defined, of less than 2.5 to 1.0 and in respect of the incurrence of secured indebtedness, limits the amount to less than 65% of the present value of future net revenues from our proved petroleum and natural gas reserves discounted at an annual rate of 10%. At the end 2008, 65% of the present value of the future net revenues from our proved petroleum and natural gas reserves discounted at an annual rate of 10% is approximately $1.91 billion. Our $7^{7/8}$% Senior Notes are rated by both Standard and Poor's Ratings Services ("S&P") and Moody's Investors Service who have assigned a corporate rating of "B" and "B3", respectively, and have rated the $7^{7/8}$% Senior Notes as "CCC+" and "Caa1", respectively. Recently, S&P has revised its ratings outlook from stable to negative reflecting an expectation of lower upstream production and weakened financial metrics as a result of low hydrocarbon prices.

Currently, we have $916.7 million of principal amount of Convertible Debentures issued in seven series with conversion privileges to Trust Units at prices that range from $13.85 to $46.00. With our Trust Units currently trading in the $5 to $7 range, we do not anticipate there will likely be many conversions until the trading value of our Trust Units appreciates significantly. The most restrictive term of the Convertible Debentures limits the issuance of additional Convertible Debentures if the principal amount of all issued and outstanding Convertible Debentures immediately after the issuance exceed 25% of the total market capitalization, being an aggregate of the principal amount of all issued and outstanding Convertible Debentures plus an amount equal to the current market price of all of the issued and outstanding Trust Units. At March 31, 2009, our total market capitalization was approximately $1.7 billion which would prohibit the issuance of further Convertible Debentures.

During 2009, the trading value of our trust units ranged from a high of $11.91 in January to a low of $3.87 in March, reflecting the general trend in the financial markets. The following summarizes the trading value of our Trust Units year-to-date for 2009:

	Trading Price		
Month	**High**	**Low**	**Volume**
TSX Trading			
January 2009	$ 11.91	$ 10.36	10,266,136
February 2009	$ 10.57	$ 5.87	13,739,710
March 2009	$ 6.20	$ 3.87	16,343,646
April 2009	$ 6.18	$ 4.44	8,769,868
May 1 to 8, 2009	$ 8.72	$ 5.71	4,394,864
NYSE Trading (US$)			
January 2009	$ 10.10	$ 8.25	25,461,464
February 2009	$ 8.55	$ 4.69	36,881,966
March 2009	$ 4.83	$ 3.00	36,763,788
April 2009	$ 5.08	$ 3.50	21,501,439
May 1 to 8, 2009	$ 7.47	$ 4.80	13,038,812

We are authorized to issue an unlimited number of Trust Units and at the end of the First Quarter of 2009, approximately 72% of the 161,508,947 Trust Units issued were held by non-residents of Canada.

During the First Quarter of 2009, we did not purchase any securities pursuant to our Normal Course Issuer Bid and continue to have approval to purchase for cancellation at prevailing market prices up to 14,826,261 Trust Units as well as up to $91.4 million principal amount of Convertible Debentures.

Concurrent with our purchase of our downstream assets in 2006, we entered into a Supply and Offtake Agreement that required the ownership of all crude oil feedstock and substantially all of the refined product inventory at the refinery be retained by Vitol Refining S.A. (an international oil trader) and granted Vitol the right and obligation to provide and deliver crude oil feedstock to the refinery as well as the right and obligation to purchase 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 refined products held for sale, except for HSFO. For a more complete description of this Supply and Offtake Agreement, see the discussion of the Supply and Offtake Agreement in our Annual Information Form for the year ended December 31, 2008 filed on SEDAR at www.sedar.com. Currently, the Supply and Offtake Agreement may be terminated by either Vitol or Harvest with six months prior notice. Pursuant to the Supply and Offtake Agreement, we estimate that Vitol held inventories of VGO and crude oil feedstock (both delivered and in-transit valued at approximately $246.2 million at March 31, 2009 ($319.7 million at December 31, 2008) which would otherwise have 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 although debt repayment obligations may reduce future distributions paid to Unitholders.

SUMMARY OF QUARTERLY RESULTS

The following table and discussion highlights our First Quarter of 2009 relative to the preceding seven quarters:

	2009	2008				2007		
(000s except where noted)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Revenue, net of royalties	**$731,095**	$892,739	$1,597,195	$1,622,079	$1,377,352	$ 879,124	$1,031,514	$1,133,450
Net income (loss)	**$ 56,864**	$ 78,640	$ 295,788	$(162,063)	$ (346)	$(113,585)	$ 11,811	$ 6,248
Per Trust Unit, basic(1)	**$ 0.36**	$ 0.50	$ 1.93	$ (1.07)	$ -	$ (0.77)	$ 0.08	$ 0.05
Per Trust Unit, diluted(1)	**$ 0.36**	$ 0.50	$ 1.73	$ (1.07)	$ -	$ (0.77)	$ 0.08	$ 0.05
Cash from operating activities	**$ 221,745**	$ 183,740	$ 133,493	$ 210,534	$ 128,119	$ 87,998	$ 191,049	$ 251,218
Per Trust Unit, basic	**$ 1.40**	$ 1.18	$ 0.87	$ 1.39	$ 0.85	$ 0.60	$ 1.31	$ 1.88
Per Trust Unit, diluted	**$ 1.28**	$ 1.10	$ 0.84	$ 1.26	$ 0.83	$ 0.60	$ 1.22	$ 1.67
Distributions per Unit, declared	**$ 0.65**	$ 0.90	$ 0.90	$ 0.90	$ 0.90	$ 0.98	$ 1.14	$ 1.14
Total long-term financial debt	**$2,373,925**	$ 2,352,196	$2,284,664	$2,105,998	$2,209,451	$2,172,417	$2,097,187	$1,987,352
Total assets	**$5,785,269**	$5,745,407	$5,659,227	$5,637,879	$5,574,528	$5,451,683	$5,585,651	$5,613,333

(1) The sum of the interim periods does not equal the total per year amount as there were large fluctuations in the weighted average number of Trust Units outstanding in each individual quarter.

Net revenues are comprised of revenues net of royalties from our upstream operations as well as sales of refined products from our downstream operations. Revenues throughout 2007 remained relatively stable until the Fourth Quarter when the refinery throughput decreased due to a planned shutdown for more than half the quarter. Throughout the first three quarters of 2008, net revenues 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 through to the First Quarter 2009, resulted in a significant decrease in net revenues.

The growth in cash from operating activities is closely aligned with the trend in commodity prices for our upstream operations, reflects the cyclical nature of the downstream segment, and is significantly impacted by changes in working capital. In the First Quarter of 2009, cash from operating activities has increased from the previous quarter mainly reflecting increased refining margins.

Net income reflects both cash and non-cash items. Changes in non-cash items, including future income tax, DDA&A expense, unrealized foreign exchange gains and losses, unrealized gains on risk management contracts and Trust Unit right compensation expense cause net income to vary significantly from period to period. In the Second Quarter of 2007 Bill C-52 was enacted, which imposed a new tax on distributions from publicly traded income trusts resulting in a large future income tax expense in the quarter. In the Fourth Quarter of 2007 Bill C-28 implemented reductions in the federal corporate income tax rates which will also apply to the tax on distributions from publicly traded mutual fund trusts, resulting in a significant future income tax recovery in the quarter. Changes in the fair value of our risk management contracts have also contributed to the volatility in net income (loss) over the preceding eight quarters. For these reasons, our net income (loss) does not reflect the same trends as net revenues or cash from operating activities, nor is it expected to.

Total assets over the last eight quarters have remained relatively stable. The stability reflects moderate acquisition activity offset by a reduction in net book value associated with depletion and depreciation charges. Total long term financial liabilities have also remained relatively stable over the last eight quarters, reflecting moderate acquisition activity, offset by the issuance of Trust Units in the Second Quarter of 2007, and a net cash surplus of cash from operating activities over distributions to Unitholders.

OUTLOOK

As anticipated, the First Quarter of 2009 has been challenging with the global economic slowdown and financial crisis continuing to limit liquidity in the financial markets and causing a reduction in demand for crude oil as well as refined products. However, by the end of the quarter, there was some sense of generally improving conditions. In light of these conditions, we are very pleased with the contribution from our downstream business during the First Quarter which enabled us to maintain our bank borrowings at $1,233.8 million, essentially unchanged from year end. Since the end of the First Quarter, the WTI benchmark price for crude oil has strengthened somewhat trading in the US$50 range and the equity markets have shown some meaningful recovery in trading prices which has offset the impact of a strengthening in the Canadian dollar and the deterioration of refining margins for distillate products.

As recovery of the global economy and stability in the financial markets remains uncertain, we have reduced our monthly distribution to $0.05 per Trust Unit commencing with the March 2009 distribution and continue to target capital spending for 2009 at less than $220 million with any excess cash flow directed towards debt repayment. We expect weak financial performance during the Second Quarter of 2009 as our upstream operations will continue to be impacted by low commodity prices and the contribution from our downstream operations will be negative with the refinery shutdown from early April through mid-May for a scheduled turnaround of the hydrocracking unit. For the last half of 2009, we anticipate that both our upstream and downstream business units will operate at full capacity with financial performance dependent on commodity prices and the Canadian/US dollar exchange rate.

In our upstream operations, we estimate capital spending for the remainder of 2009 will be approximately $60 million and continue to expect production to average approximately 50,000 boe/d for calendar 2009 comprised of 35,000 bbl/d of oil and natural gas liquids and 90,000 mcf/d of natural gas. For the balance of 2009, our capital spending will continue to focus on Enhanced Oil Recovery projects with commencement of polymer injection at Wainwright while we monitor the benefits of our enhanced waterflood project at Bellshill Lake and Suffield completed in 2008 and early 2009. Our drilling plan will focus on oil/liquids weighted opportunities where we benefit from the Alberta Government's New Royalty Framework. We will continue to focus on opportunities to reduce costs including general and administrative and operating costs as well as capital expenditures, by seeking competitive reductions in equipment and services provided by third parties. We are continuing to forecast general and administrative costs at roughly $1.50 per boe and operating costs to range between $15.00 to $16.00 per boe.

In our downstream operations, we had planned to shutdown the refinery for the month of April for a turnaround of the hydrocracking unit including the replacement of spent catalyst. However, as refining margins deteriorated during the month of March, we expanded the planned shutdown to include a shutdown of the crude unit to allow the replacement of catalyst in the distillate hydrotreating unit (originally planned for 2010) and have "paced" the turnaround to improve labour productivity and reduce labour cost by avoiding overtime and other premium pay. As a consequence of this, the shutdown of the refinery has been extended from 35 days to approximately 45 days with the benefit of improved labour productivity and lower costs expected to offset the lost gross margin from the extended shutdown. The expected cost of our expanded turnaround and catalyst replacement is approximately $46 million.

During the Second Quarter of 2009, we expect that the throughput of the refinery will average approximately 54,000 bbl/d of feedstock as compared to an average of approximately 116,000 bbl/d for the last half of 2009. For the last half of 2009, we expect our operating costs will continue to average approximately $1.90/bbl of throughput and our cost of purchased energy will average slightly less than $3.00/bbl of throughput reflecting an exchange rate expectation of approximately US$0.82 per Cdn$1.00 and a reduction in the consumption of internally produced HSFO and butane. We expect capital spending in our downstream operations to be approximately $50 million, with $10 million to be spent on the $300 million refinery debottlenecking project. The annual cash flow contribution from our Downstream Marketing Division is expected to be approximately $24 million, unchanged from our previous guidance.

During the First Quarter of 2009, we did not enter into any additional commodity price contracts resulting in approximately 68% of our WTI sensitive cash flow in the Second Quarter of 2009 price protected with 12,000 bbl/d of heating oil and 8,000 bbl/d of fuel oil price under contract. The heating oil price contracts provide downside protection equivalent to market price plus US$13.93/bbl when prices are lower than US$72.59 and provide a price of US$86.52 when the market price is between US$72.59 and US$86.52 with our upside participation limited to US$98.73/bbl. The fuel oil price contracts provide downside protection equivalent to market price plus US$7.63 per bbl when prices are lower than US$49.75 and provide a price of US$57.38 when the market price is between US$49.75 and US$57.38 with our upside participation limited to US$65.89 per bbl. Beyond June 30, 2009, we have no commodity price contracts in place.

During the First Quarter of 2009, we entered into currency exchange rate contracts that fixed the exchange rate on US$15 million per month for the period from July through December 2009 at approximately US$0.78/Cdn$1.00 representing approximately 25% of our currency exchange rate exposure, prior to considering the offsetting exposure of our US dollar denominated 7 7/8% Senior Notes. In addition, we have entered into contracts to fix the price of 10 MWh of Alberta power prices for the period from April through December 2009 at an average price of $61.90 with the objective of reducing the volatility of our operating costs to fluctuating electricity costs which represent approximately 25% of our upstream operating costs.

We manage our exposure to fluctuations in interest rates by maintaining a mix of short and longer term financing with the short term financing typically carrying floating interest rates and longer term financing (our 7⁷/⁸% Senior Notes and Convertible Debentures) carrying fixed rates of interest. Our short term financing consists of bank borrowings under our credit facilities which totaled $1,233.8 million at March 31, 2009, representing approximately 50% of our total debt. As a result, approximately 50% of our interest rate exposure is floating and 50% is fixed. Currently, our most significant exposure to increasing interest rates is through the re-pricing of bank borrowings as we renew our credit facilities or enter into additional longer term financings. In October 2011, our US$250 million of 7⁷/⁸% Senior Notes mature and the re-financing of this maturity also presents an exposure to increased borrowing costs while the maturing of the $916.7 million of principal amount of Convertible Debentures (2009 - $2.5 million; 2010 - $37.1 million; 2012 – $174.6 million; 2013 - $379.3 million; 2014 - $73.2 million and 2015 - $250 million) will not necessarily result in an exposure to increased borrowing costs as we anticipate that as these Convertible Debentures mature, or are converted into Trust Units before their maturity date, the principal amount will be settled with the issuance of Trust Units.

While we do not forecast commodity prices nor refining margins, we may enter into commodity price risk management contracts from time-to-time to mitigate some portion of our price volatility with the objective of stabilizing our cash flow from operating activities. The following table reflects the sensitivity of our 2009 cash flow from operating activities over the remaining nine months of the year to changes in the following benchmark prices:

	Assumption	**Change**	**Impact on Cash Flow**
WTI oil price (US$/bbl)	$ 54.00	$ 5.00	$ 0.19 / Unit
CAD/USD exchange rate	$ 0.82	$ 0.05	$ 0.17 / Unit
AECO daily natural gas price	$ 3.90	$ 1.00	$ 0.14 / Unit
Refinery crack spread (US$/bbl)	$ 6.35	$ 1.00	$ 0.20 / Unit
Upstream operating expenses (per boe)	$ 16.00	$ 1.00	$ 0.08 / Unit

Overall, we expect that based on current commodity price expectations, our 2009 cash from operating activities will be sufficient to fund our planned capital expenditures. In prior years, we have balanced our cash from operating activities and the funding of capital expenditures and distributions paid to Unitholders with reliance on the proceeds from our distribution reinvestment programs for any shortfalls. In light of the significant reduction in commodity prices over the past three quarters, we significantly reduced capital spending plans for 2009 and effective March 2009, have reduced monthly distributions from $0.30 per Trust Unit to $0.05 per Trust Unit resulting in expected cash savings of approximately $90 million and $284 million (net of participation in distribution reinvestment programs), respectively.

As we look forward to the maturity of our $1.6 billion Extendible Credit Facility and consider the reduced availability of liquidity/credit and our reduced cash flow with lower commodity prices, it is prudent to direct any excess cash flow to debt repayment as we plan to reduce our bank borrowings to approximately $1 billion by April 2010, the maturity date of the Extendible Credit Facilities. Based on current commodity price expectations, our net cash flow after capital spending will not be sufficient to achieve our target of less than $1 billion of bank borrowings. Accordingly, over the next year, we will be considering some combination of the following initiatives to reach our target: the sale of non-core assets and the possible reduction of distributions to Unitholders as well as the issuance of additional equity and unsecured debt. A target approaching $1 billion in bank borrowings is based on a prudent evaluation of our debt capacity and available credit.

We continue to review and evaluate the impact of the enacted and proposed changes to the tax on distributions to Unitholders effective January 1, 2011 and while there has been no decision at this time, we are more likely to convert to a corporation while retaining the income tax advantages until 2011.

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 are settled and when these activities are recognized for accounting purposes. Changes in these estimates could have a material impact on our reported results. These estimates are described in detail in our MD&A for the year ended December 31, 2008 as filed on SEDAR at www.sedar.com. There have been no significant changes to any of our critical accounting estimates in our consolidated financial statements for the three months ended March 31, 2009 from those described in our annual MD&A.

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

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 mid-2008, the ASB issued an exposure draft to incorporate IFRS into the Canadian accounting standards. In September 2008, the International Accounting Standards Board ("IASB") issued an exposure draft proposing amendments for first time adopters of IFRS to enable an entity to measure exploration and evaluation assets at the amount determined under the entity's previous accounting principles and it also provides for the measurement of oil and gas assets in the development or production phase, among other things, by allocating the amount determined by the entity's previous accounting principles to the underlying assets on a pro rata basis using reserve volumes or reserve values at the date of transition. If formally approved by the IASB, these amendments will substantially ease the adoption of IFRS for Harvest.

We have established an IFRS Conversion Plan and have staffed a project team with regular reporting to our senior management team and to the Audit Committee of the Board of Directors. We have completed an initial assessment of the differences between Canadian accounting standards and IFRS and are currently completing a comprehensive assessment of the impact of adopting IFRS on our accounting policies, information technology and data systems, internal control over financial reporting, disclosure controls and procedures, financial reporting expertise as well as business activities that may be influenced such as debt covenants, capital requirements and compensation arrangements. At this stage in the project we are unable to determine the full impact of adopting IFRS on Harvest's financial position and future results.

OPERATIONAL AND OTHER BUSINESS RISKS

Both Harvest's upstream operations and its downstream operations are conducted in the same business environment as most other operators in the respective businesses and the business risks are very similar. However, our structure as a publicly traded mutual fund trust is significantly different than that of a traditional corporation with share capital and there are some unique business risks of our structure. In addition, Harvest's monthly cash distributions limits its accumulation of capital resources from internal sources. We intend to continue executing our business plan to create value for Unitholders by increasing the net asset value per Trust Unit with our risk management activities carried out under policies approved by our Board of Directors.

We have segregated the identification of business risks into those generally applicable to upstream operations as well as downstream operations and those applicable to our royalty trust structure and these should be read in conjunction with the full description of these risks in our Annual Information Form for the year ended December 31, 2008 filed on www.sedar.com. The following summarizes the more significant risks:

Upstream Operations

- Prices received for petroleum and natural gas have fluctuated widely in recent years and are also impacted by the volatility in the Canadian/US currency exchange rate.
- The differential between light oil and heavy oil compounds the fluctuations in the benchmark oil prices.
- The operation of petroleum and natural gas properties involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected and/or dangerous conditions.
- The production of petroleum and natural gas may involve a significant use of electrical power and since de-regulation of the electric system in Alberta, electrical power prices in Alberta have been volatile.
- The markets for petroleum and natural gas produced in western Canada depend upon available capacity to refine crude oil and process natural gas as well as pipeline capacity to transport the products to consumers.
- The reservoir and recovery information in reserve reports are estimates and actual production and recovery rates may vary from the estimates and the variations may be significant.
- Absent capital reinvestment, production levels from petroleum and natural gas properties will decline over time and absent commodity price increases, cash generated from operating these assets will also decline.
- Prices paid for acquisitions are based in part on reserve report estimates and the assumptions made preparing the reserve reports are subject to change as well as geological and engineering uncertainty.
- The operation of petroleum and natural gas properties is subject to environmental regulation pursuant to local, provincial and federal legislation and a breach of such legislation may result in the imposition of fines as well as higher operating standards that may increase costs.

Downstream Operations

- The market prices for crude oil and refined products have fluctuated significantly, the direction of the fluctuations may be inversely related and the relative magnitude may be different resulting volatile refining margins.
- The prices for crude oil and refined products are generally based in US dollars while our operating costs are denominated in Canadian dollars which introduces currency exchange rate exposure.
- Crude oil feedstock is delivered to our refinery via waterborne vessels which could experience delays in transporting supplies due to weather, accidents, government regulations or third party actions.
- Over 60% of our feedstock in 2008 was supplied from sources in Iraq and if Iraq curtails supply, we may not be able to find another source with an adequate amount of a similar type of crude oil.
- We are relying on the marketing ability and 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 and we would be required to find another counterparty to our Supply and Offtake Agreement.
- Our refinery is a single train integrated interdependent facility which could experience a major accident, be damaged by sever weather or otherwise be forced to shutdown which may reduce or eliminate our cash flow.

- Our refining operations which include the transportation and storage of a significant amount of crude oil and refined products are adjacent to environmentally sensitive coastal waters, and are subject to hazards and similar risks such as fires, explosions, spills and mechanical failures, any of which may result in personal injury, damage to our property and/or the property of others along with significant other liabilities in connection with a discharge of materials.
- The production of aviation fuels subjects us to liability should contaminants in the fuel result in aircraft engines being damaged and/or aircraft crashes.
- Collective agreements with our employees and the United Steel Workers of America may not prevent a strike or work stoppage and future agreements may result in an increase in operating costs.
- Refinery operations are subject to environmental regulation pursuant to local, provincial and federal legislation and a breach of such legislation may result in the imposition of fines as well as higher operating standards that may increase costs.

General Business Risks

- The loss of a member to our senior management team and/or key technical operations employee could result in a disruption to either our upstream or downstream operations.
- Our credit facility and other financing agreements contain financial covenants and maturity dates that may limit our ability to sell assets, enter into certain financing arrangements and/or pay distributions to Unitholders.
- Variations in interest rates on our current and/or future financing arrangements may result in significant increases in our borrowing costs and result in less cash available for distributions to Unitholders.
- Our crude oil sales and refining margins are denominated in US dollars while we pay distributions to our Unitholders in Canadian dollars which results in currency exchange rate exposure.

Royalty Trust Structural Risks

- Trust Units are hybrid securities in that they share certain attributes common to both equity securities and debt instruments and represent a fractional interest in the Trust.
- Recent changes to income tax legislation related to the royalty trust structure will result in a tax, at the trust level of our structure, on distributions from Harvest at rates of tax comparable to the combined federal and provincial corporate income tax rates in Canada and to treat such distributions as dividends to the Unitholders for income tax purposes.

CHANGES IN REGULATORY ENVIRONMENT

For a detailed discussion of the most recent changes to our regulatory environment, please refer to our MD&A for the year ended December 31, 2008 as filed on SEDAR at www.sedar.com.

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 (UNAUDITED)

(thousands of Canadian dollars)		**March 31, 2009**		December 31, 2008
Assets				
Current assets				
Accounts receivable and other	**$**	**160,897**	$	173,341
Fair value of risk management contracts *[Note 12]*		**25,699**		36,087
Prepaid expenses and deposits		**11,934**		11,843
Inventories *[Note 3]*		**77,204**		55,788
		275,734		277,059
Property, plant and equipment *[Note 4]*		**4,500,771**		4,468,505
Intangible assets *[Note 5]*		**107,236**		106,002
Goodwill		**901,528**		893,841
	$	**5,785,269**	$	5,745,407
Liabilities and Unitholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities	**$**	**229,605**	$	210,097
Cash distribution payable		**8,075**		47,160
Current portion of convertible debentures *[Note 8]*		**2,520**		2,513
Fair value deficiency of risk management contracts *[Note 12]*		**38**		235
		240,238		260,005
Bank loan *[Note 7]*		**1,233,843**		1,226,228
$7^{7/8}$% Senior notes		**309,325**		298,210
Convertible debentures *[Note 8]*		**828,237**		825,246
Asset retirement obligation *[Note 6]*		**280,312**		277,318
Employee future benefits *[Note 11]*		**9,895**		10,551
Deferred credit		**441**		522
Future income tax		**206,008**		203,998
Unitholders' equity				
Unitholders' capital *[Note 9]*		**3,927,914**		3,897,653
Equity component of convertible debentures		**84,100**		84,100
Contributed surplus		**6,433**		6,433
Accumulated income		**515,748**		458,884
Accumulated distributions		**(1,994,976)**		(1,891,674)
Accumulated other comprehensive income		**137,751**		87,933
		2,676,970		2,643,329
	$	**5,785,269**	$	5,745,407

Commitments, contingencies and guarantees *[Note 14]*

Subsequent events *[Note 15]*

See accompanying notes to these consolidated financial statements.

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

(thousands of Canadian dollars, except per Trust Unit amounts)		**Three months ended March 31, 2009**		Three months ended March 31, 2008
Revenue				
Petroleum, natural gas, and refined product sales	**$**	**755,624**	$	1,439,752
Royalty expense		**(24,529)**		(62,400)
		731,095		1,377,352
Expenses				
Purchased products for processing and resale		**381,837**		959,992
Operating		**120,110**		141,345
Transportation and marketing		**5,911**		11,622
General and administrative *[Note 10]*		**7,749**		12,477
Realized net (gains) losses on risk management contracts *[Note 12]*		**(25,542)**		36,294
Unrealized net losses on risk management contracts *[Note 12]*		**10,191**		60,858
Interest and other financing charges on short term debt, net		**60**		201
Interest and other financing charges on long term debt		**32,592**		35,103
Depletion, depreciation, amortization and accretion		**139,196**		130,925
Currency exchange loss		**98**		10,665
Large corporations tax and other tax		**19**		50
Future income tax expense (recovery)		**2,010**		(21,834)
		674,231		1,377,698
Net income (loss) for the period		**56,864**		(346)
Other comprehensive income				
Cumulative translation adjustment		**49,818**		50,513
Comprehensive income for the period	$	**106,682**	$	50,167
Net income per trust unit, basic *[Note 9]*	**$**	**0.36**	$	-
Net income per trust unit, diluted *[Note 9]*	**$**	**0.36**	$	-

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY (UNAUDITED)

(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)**
Convertible debenture conversions											
9% Debentures Due 2009	7		-		-		-		-		-
8% Debentures Due 2009	31		-		-		-		-		-
10.5% Debentures Due 2008	13		(3)		-		-		-		-
Redemption of convertible debentures											
10.5% Debentures Due 2008	24,249		(6,433)		6,433		-		-		-
Exercise of unit appreciation rights and other	805		-		-		-		-		-
Issue costs	(14)		-		-		-		-		-
Currency translation adjustment	-		-		-		-		-		50,513
Net loss	-		-		-		(346)		-		-
Distributions and distribution reinvestment plan	35,890		-		-		-		(135,166)		-
At March 31, 2008	**$3,797,061**	**$**	**33,101**	**$**	**6,433**	**$**	**246,519**	**$**	**(1,475,515)**	**$**	**(146,246)**
At December 31, 2008	**$3,897,653**	**$**	**84,100**	**$**	**6,433**	**$**	**458,884**	**$**	**(1,891,674)**	**$**	**87,933**
Exercise of unit appreciation rights and other	223		-		-		-		-		-
Currency translation adjustment	-		-		-		-		-		49,818
Net income	-		-		-		56,864		-		-
Distributions and distribution	30,038		-		-		-		(103,302)		-
At March 31, 2009	**$3,927,914**	**$**	**84,100**	**$**	**6,433**	**$**	**515,748**	**$**	**(1,994,976)**	**$**	**137,751**

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(thousands of Canadian dollars)		**Three months ended March 31, 2009**		Three months ended March 31, 2008
Cash provided by (used in)				
Operating Activities				
Net income (loss) for the period	**$**	**56,864**	$	(346)
Items not requiring cash				
Depletion, depreciation, amortization and accretion		**139,196**		130,925
Unrealized currency exchange (gain) loss		**(420)**		9,866
Non-cash interest expense and amortization of finance charges		**4,182**		2,511
Unrealized loss on risk management contracts *[Note 12]*		**10,191**		60,858
Future income tax expense (recovery)		**2,010**		(21,834)
Unit based compensation (recovery) expense		**(1,447)**		3,234
Employee benefit obligation		**(656)**		169
Other non-cash items		**(25)**		3
Settlement of asset retirement obligations *[Note 6]*		**(3,466)**		(2,253)
Change in non-cash working capital		**15,316**		(55,014)
		221,745		128,119
Financing Activities				
Bank borrowings *[Note 7]*		**7,016**		50,386
Financing costs		**(94)**		(14)
Cash distributions		**(73,264)**		(98,423)
Change in non-cash working capital		**(33,075)**		67
		(99,417)		(47,984)
Investing Activities				
Additions to property, plant and equipment		**(115,614)**		(85,598)
Property (acquisitions) dispositions, net		**(675)**		(185)
Change in non-cash working capital		**(6,156)**		5,646
		(122,445)		(80,137)
Change in cash and cash equivalents		**(117)**		(2)
Effect of exchange rate changes on cash		**117**		2
Cash and cash equivalents, beginning of period		**-**		-
Cash and cash equivalents, end of period	**$**	**-**	$	-
Interest paid	**$**	**13,979**	$	24,041
Large corporation tax and other tax paid	**$**	**19**	$	50

See accompanying notes to these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Period ended March 31, 2009

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

1. Significant Accounting Policies

These interim consolidated financial statements of Harvest Energy Trust (the "Trust" or "Harvest") have been prepared by management in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). 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. In the opinion of management, these financial statements have been prepared within reasonable limits of materiality. These interim consolidated financial statements follow the same significant accounting policies as described and used in the consolidated financial statements of Harvest for the year ended December 31, 2008 which should be read in conjunction with that report.

These consolidated financial statements include the accounts of the Trust, its wholly owned subsidiaries and its proportionate interest in a partnership with a third party.

2. Change in Accounting Policy

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.

3. Inventories

	March 31, 2009	December 31, 2008
Petroleum products		
Upstream – pipeline fill	$ **267**	$ 603
Downstream	**60,818**	50,311
	61,085	50,914
Parts and supplies	**16,119**	4,874
Total inventories	$ **77,204**	$ 55,788

4. Property, Plant and Equipment

	March 31, 2009			December 31, 2008		
	Upstream	**Downstream**	**Total**	Upstream	Downstream	Total
Cost	**$ 4,820,212**	**$ 1,553,268**	**$ 6,373,480**	$ 4,710,725	$ 1,493,039	$ 6,203,764
Accumulated depletion	**(1,683,406)**	**(189,303)**	**(1,872,709)**	(1,572,449)	(162,810)	(1,735,259)
Net book value	**$ 3,136,806**	**$ 1,363,965**	**$ 4,500,771**	$ 3,138,276	$ 1,330,229	$ 4,468,505

General and administrative costs of $2.5 million (2008 – $3.2 million) have been capitalized during the three months ended March 31, 2009, which includes a recovery of $0.3 million (2008 – costs of $0.7 million) related to the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan.

5. Intangible Assets

	March 31, 2009			December 31, 2008		
	Cost	**Accumulated Amortization**	**Net book value**	Cost	Accumulated Amortization	Net book value
Engineering drawings	**$ 112,255**	**$ (13,798)**	**$ 98,457**	$ 108,402	$ (11,969)	$ 96,433
Marketing contracts	**7,807**	**(2,816)**	**4,991**	7,539	(2,480)	5,059
Customer lists	**4,727**	**(1,162)**	**3,565**	4,564	(1,008)	3,556
Fair value of office lease	**931**	**(708)**	**223**	931	(652)	279
Financing costs	**7,300**	**(7,300)**	**-**	7,300	(6,625)	675
Total	**$ 133,020**	**$ (25,784)**	**$ 107,236**	$ 128,736	$ (22,734)	$ 106,002

6. 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 $1,211 million which will be incurred between 2009 and 2058. The majority of the costs will be incurred between 2015 and 2040. A credit-adjusted risk-free discount rate of 8% - 10% and inflation rate of approximately 2% were used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

	March 31, 2009	December 31, 2008
Balance, beginning of period	**$ 277,318**	$ 213,529
Incurred on acquisition of a private corporation	**-**	1,900
Liabilities incurred	**405**	4,371
Revision of estimates	**-**	49,395
Net liabilities acquired (settled) through acquisition (disposition)	**-**	910
Liabilities settled	**(3,466)**	(11,418)
Accretion expense	**6,055**	18,631
Balance, end of period	**$ 280,312**	$ 277,318

7. Bank Loan

At March 31, 2009, Harvest had $1,233.8 million drawn of the $1.6 billion available under the Credit Facility ($1,226.2 million drawn at December 31, 2008) which matures on April 30, 2010.

The Credit Facility is secured by a $2.5 billion first floating charge over all of the assets of Harvest's operating subsidiaries plus a first mortgage security interest on the refinery assets of North Atlantic. The most restrictive covenants of Harvest's credit facility include an aggregate limitation of $25 million on financial assistance and/or capital contributions to parties other than those included in the first floating charge, a limitation to carrying on business in countries that are not members of the Organization of Economic Co-operation and Development and a limitation on the payment of distributions to Unitholders in certain circumstances including 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 (as described in Note 11 in the consolidated financial statements for the year ended December 31, 2008), availability is subject to the following quarterly financial covenants:

	Covenant	As at March 31, 2009
Secured debt to EBITDA	3.0 to 1.0 or less	1.5
Total senior debt to EBITDA	3.5 to 1.0 or less	1.8
Secured debt to Capitalization	50% or less	24%
Total senior debt to Capitalization	55% or less	31%

For the three months ended March 31, 2009, Harvest's average interest rate on advances under the Credit Facility was 2.01% (2008 – 4.83%).

8. Convertible Debentures

At March 31, 2009, Harvest had seven series of Convertible Unsecured Subordinated Debentures outstanding, the details of which have been outlined in Harvest's consolidated financial statements for the year ended December 31, 2008.

The following table summarizes the face value, carrying amount and fair value of the Convertible Debentures:

	March 31, 2009			December 31, 2008		
	Face Value	**Carrying Amount(1)**	**Fair Value**	Face Value	Carrying Amount(1)	Fair Value
9% Debentures Due 2009	**$ 944**	**$ 942**	**$ 944**	$ 944	$ 940	$ 984
8% Debentures Due 2009	**1,588**	**1,578**	**1,588**	1,588	1,573	1,540
6.5% Debentures Due 2010	**37,062**	**35,577**	**27,797**	37,062	35,387	29,650
6.4% Debentures Due 2012	**174,626**	**169,745**	**73,884**	174,626	169,455	75,089
7.25% Debentures Due 2013	**379,256**	**359,412**	**157,202**	379,256	358,533	166,835
7.25% Debentures Due 2014	**73,222**	**67,766**	**35,842**	73,222	67,549	36,611
7.5% Debentures Due 2015	**250,000**	**195,737**	**105,000**	250,000	194,322	107,500
	$ 916,698	**$ 830,757**	**$ 402,257**	$ 916,698	$ 827,759	$ 418,209

(1)Excluding the equity component.

9. Unitholders' Capital

(a) Authorized

The authorized capital consists of an unlimited number of Trust Units.

(b) Number of Units Issued

	Three months ended March 31	
	2009	2008
Outstanding, beginning of period	**157,200,701**	148,291,170
Convertible debenture conversions		
9% Debentures Due 2009	**-**	505
8% Debentures Due 2009	**-**	1,928
10.5% Debentures Due 2008	**-**	344
Redemption of convertible debentures		
10.5% Debentures Due 2008	**-**	1,166,593
Distribution reinvestment plan issuance	**4,252,949**	1,637,601
Exercise of unit appreciation rights and other	**55,297**	37,583
Outstanding, end of period	**161,508,947**	151,135,724

(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		**March 31, 2009**		March 31, 2008
Net income (loss), basic	**$**	**56,864**	$	(346)
Interest on Convertible Debentures		**23**		-
Net income (loss), diluted[(1)]	**$**	**56,887**	$	(346)

Weighted average Trust Units adjustments	**March 31, 2009**	March 31, 2008
Number of Units		
Weighted average Trust Units outstanding, basic	**158,892,410**	149,899,484
Effect of Convertible Debentures	**68,159**	-
Effect of Employee Unit Incentive Plans	**-**	-
Weighted average Trust Units outstanding, diluted[(2)]	**158,960,569**	149,899,484

(1) Net income (loss), diluted excludes the impact of the conversions of certain of the Convertible Debentures of $19.1 million for the three months ended March 31, 2009 (2008 - $13.3 million) as the impact would be anti-dilutive.

(2) Weighted average Trust Units outstanding, diluted for the three months ended March 31, 2009 does not include the unit impact of 28,679,854 for certain of the Convertible Debentures (2008 – 20,031,150) and nil (2008 – 121,294) for the Employee Unit Incentive Plans as the impact would be anti-dilutive.

10. Employee Unit Incentive Plans

Trust Unit Rights Incentive Plan

The following summarizes the Trust Units reserved for issuance under the Trust Unit Rights Incentive Plan:

	March 31, 2009		December 31, 2008	
	Unit Appreciation Rights	**Weighted Average Exercise Price**	Unit Appreciation Rights	Weighted Average Exercise Price
Outstanding, beginning of period	**8,037,466**	**$ 21.19**	3,823,683	$ 30.74
Granted	**72,400**	**9.87**	5,244,102	15.68
Exercised	**(2,500)**	**18.90**	(68,675)	25.67
Forfeited	**(292,793)**	**23.59**	(961,644)	28.80
Outstanding before exercise price reductions	**7,814,573**	**21.02**	8,037,466	21.19
Exercise price reductions	**-**	**(5.00)**	-	(4.45)
Outstanding, end of period	**7,814,573**	**16.02**	8,037,466	16.74
Exercisable before exercise price reductions	**16,750**	**$ 15.18**	85,200	$ 22.60
Exercise price reductions	**-**	**(15.04)**	-	(15.49)
Exercisable, end of period	**16,750**	**$ 0.14**	85,200	$ 7.11

The following table summarizes information about Unit Appreciation Rights outstanding at March 31, 2009.

		Outstanding			Exercisable	
Exercise Price before price reductions	**Exercise Price net of price reductions**	**At March 31, 2009**	**Weighted Average Exercise Price net of price reductions(1)**	**Remaining Contractual Life (1)**	**At March 31, 2009 (2)**	**Weighted Average Exercise Price net of price reductions(1)**
$9.31 - $12.51	$8.84 - $11.56	3,147,400	$ 9.73	4.7	-	$ -
$14.99 - $18.63	$0.01 - $17.08	48,100	10.95	3.1	16,250	0.01
$19.29 - $25.37	$4.22 - $22.83	1,863,840	19.32	3.8	500	4.22
$26.09 - $31.96	$14.58 - $24.90	1,439,183	18.05	2.8	-	-
$32.01 - $37.56	$18.48 - $28.14	1,316,050	24.34	2.1	-	-
$9.31 - $37.56	$0.01 - $28.14	7,814,573	$ 16.02	3.7	16,750	$ 0.14

(1) Based on weighted average Unit Appreciation Rights outstanding.
(2) Excludes vested Unit Appreciation Rights that are out-of-the money at period end.

Unit Award Incentive Plan ("Unit Award Plan")

The following table summarizes the Trust Units reserved for issuance under the Unit Award Incentive Plan:

Number	**March 31, 2009**	December 31, 2008
Outstanding, beginning of period	**659,137**	348,248
Granted	**5,002**	390,274
Adjusted for distributions	**46,851**	75,310
Exercised	**(42,236)**	(121,776)
Forfeitures	**(12,771)**	(32,919)
Outstanding, end of period	**655,983**	659,137
Exercisable, end of period	**254,694**	238,817

Harvest has recognized a compensation recovery of $1.3 million (2008 – expense of $3.6 million), including a non cash compensation recovery of $1.5 million (2008 – expense of $3.1 million), for the three months ended March 31, 2009, related to the Trust Unit Rights Incentive Plan and the Unit Award Plan and this is reflected in general and administrative expense in the consolidated statements of income.

11. Employee Future Benefit Plans

Defined Benefit Plans

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

	Three months ended March 31, 2009		Three months ended March 31, 2008	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Current service cost	**$ 295**	**$ 54**	$ 839	$ 92
Interest costs	**774**	**98**	667	87
Expected return on assets	**(660)**	**-**	(698)	-
Amortization of net actuarial gains	**(2)**	**-**	-	-
Net benefit plan expense	**$ 407**	**$ 152**	$ 808	$ 179

12. Financial Instruments and risk management contracts

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. The Trust's financial risk exposure and risk management strategies have not changed significantly from those described in the consolidated financial statements for the year ended December 31, 2008 in Note 20 as filed on SEDAR at www.sedar.com.

Financial instruments of Harvest consist of cash, accounts receivable, accounts payable and accrued liabilities, cash distribution payable, a credit facility, risk management contracts, Convertible Debentures and the $7^{7/8}$% Senior Notes.

At March 31, 2009, the net fair value reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $25.7 million (December 31, 2008 - $35.9 million), which was included in the balance sheet as follows: fair value of risk management contracts (current assets) $25.7 million, fair value deficiency of risk management contracts (current liabilities) $38,000.

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

Quantity	Type of Contract	Term	Average Price	Fair value
Refined Product Price Risk Management				
12,000 bbl/d	NYMEX heating oil 3-way contract	Jan. 09 – Jun. 09	US$72.59 - $98.73 ($86.52)[(a) (c)]	$ 17,837
8,000 bbl/d	Platt's fuel oil 3-way contract	Jan. 09 – Jun. 09	US$49.75 - $65.89 ($57.38)[(b)]	5,738
				$ 23,575
Natural Gas Price Risk Management				
251 GJ/d	Fixed price – natural gas contract	Jan. 09 – Dec. 09	Cdn$3.48[(d)]	**$ (38)**
Electricity Price Risk Management				
10 MWh	Electricity price swap contracts	Apr. 09 – Dec. 09	Cdn $61.90	**$ 36**
Currency Exchange Rate Risk Management				
$10,000,000/month	U.S./Cdn dollar exchange rate swap	Jul. 09 – Sep. 09	1.279 Cdn/U.S.	$ 603
$5,000,000/month	U.S./Cdn dollar exchange rate swap	Jul. 09 – Dec. 09	1.288 Cdn/U.S.	879
$10,000,000/month	U.S./Cdn dollar exchange rate swap	Oct. 09 – Dec. 09	1.279 Cdn/U.S.	606
				$ 2,088
Total net fair value of risk management contracts				**$ 25,661**

(a) If the market price is below the floor price of $72.59, the price received is market price plus $13.93; if the market price is between the floor price of $72.59 and $86.52, the price received is $86.52; if the market price is between $86.52 and the ceiling of $98.73, the price received is market price; if the market price is over the ceiling of $98.73, price received is $98.73.

(b) If the market price is below the floor of $49.75, the price received is market price plus $7.63; if the market price is between the floor price of $49.75 and $57.38, the price received is $57.38; if the market price is between $57.38 and the ceiling of $65.89, the price received is market price; if the market price is over the ceiling of $65.89, the price received is $65.89.

(c) Heating oil contracts are contracted in U.S. dollars per U.S. gallon and are presented in this table in U.S. dollars per barrel for comparative purposes (1 barrel equals 42 U.S. gallons).

(d) This contract contains an annual escalation factor such that the fixed price is adjusted each year.

For the three months ended March 31, 2009, the total unrealized loss recognized in the consolidated statement of income and comprehensive income was $10.2 million (2008 - $60.9 million), which represents the change in fair value of financial assets and liabilities classified as held for trading. The realized gains and losses on all risk management contracts are included in the period in which they are incurred.

13. 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 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] Three months ended March 31		Upstream[1] Three months ended March 31		Total Three months ended March 31	
	2009	2008	**2009**	2008	**2009**	2008
Revenue[2]	**$ 572,704**	$ 1,062,419	**$ 182,920**	$ 377,333	**$ 755,624**	$ 1,439,752
Royalties	**-**	-	**(24,529)**	(62,400)	**(24,529)**	(62,400)
Less:						
Purchased products for resale and processing	**381,837**	959,992	**-**	-	**381,837**	959,992
Operating	**44,775**	69,022	**75,335**	72,323	**120,110**	141,345
Transportation and marketing	**2,979**	8,597	**2,932**	3,025	**5,911**	11,622
General and administrative	**355**	568	**7,394**	11,909	**7,749**	12,477
Depletion, depreciation, amortization and accretion	**22,184**	16,500	**117,012**	114,425	**139,196**	130,925
	$ 120,574	$ 7,740	**$ (44,282)**	$ 113,251	**76,292**	120,991
Realized net gains (losses) on risk management contracts					**25,542**	(36,294)
Unrealized net losses on risk management contracts					**(10,191)**	(60,858)
Interest and other financing charges on short term debt, net					**(60)**	(201)
Interest and other financing charges on long term debt					**(32,592)**	(35,103)
Currency exchange loss					**(98)**	(10,665)
Large corporations tax and other tax					**(19)**	(50)
Future income tax (expense) recovery					**(2,010)**	21,834
Net income (loss)					**$ 56,864**	$ (346)
Total Assets[3]	**$ 1,831,039**	$ 1,592,586	**$ 3,928,531**	$ 3,962,295	**$ 5,785,269**	$ 5,574,528
Capital Expenditures						
Development and other activity	**$ 6,904**	$ 6,027	**$ 108,710**	$ 79,571	**$ 115,614**	$ 85,598
Property acquisitions (dispositions), net	**-**	-	**675**	185	**675**	185
Total expenditures	**$ 6,904**	$ 6,027	**$ 109,385**	$ 79,756	**$ 116,289**	$ 85,783
Property, plant and equipment						
Cost	**$ 1,553,268**	$ 1,211,860	**$ 4,820,212**	$ 4,327,478	**$ 6,373,480**	$ 5,539,338
Less: Accumulated depletion, depreciation, amortization and	**(189,303)**	(90,206)	**(1,683,406)**	(1,252,173)	**(1,872,709)**	(1,342,379)
Net book value	**$ 1,363,965**	$ 1,121,654	**$ 3,136,806**	$ 3,075,305	**$ 4,500,771**	$ 4,196,959
Goodwill						
Beginning of period	**$ 216,230**	$ 175,984	**$ 677,611**	$ 676,794	**$ 893,841**	$ 852,778
Addition to goodwill	**7,687**	6,249	**-**	-	**7,687**	6,249
End of period	**$ 223,917**	$ 182,233	**$ 677,611**	$ 676,794	**$ 901,528**	$ 859,027

[1] Accounting policies for segments are the same as those described in the consolidated financial statements for the year ended December 31, 2008 in Note 2 as filed on SEDAR at www.sedar.com.

[2] Of the total downstream revenue for the three months ended March 31, 2009, two customers represent sales of $366.8 million and $98.1 million respectively (2008 - $800.9 million and $98.9 million). No other single customer within either division represents greater than 10% of Harvest's total revenue.

[3] Total Assets on a consolidated basis includes $25.7 million (2008 – $19.6 million) relating to the fair value of risk management contracts.

[4] There is no intersegment activity.

14. Commitments, Contingencies and Guarantees

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

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

(a) *Canada Revenue Agency Assessment*
In January 2009, Canada Revenue Agency issued a Notice of Reassessment to Harvest Energy Trust in respect of its 2002 through 2004 taxation years claiming past taxes, interest and penalties totaling $6.2 million. The CRA has adjusted Harvest Energy Trust's taxable income to include their net profits interest royalty income on an accrual basis whereas the tax returns had reported this revenue on a cash basis. A Notice of Objection has been filed with CRA requesting the adjustments to an accrual basis be reversed. The Harvest Energy Trust 2005 tax return has also been prepared on a cash basis for royalty income with no taxes payable and, if reassessed by CRA on a similar basis, there would have been approximately $40 million of taxes owing. The Harvest Energy Trust 2006 tax return has been prepared on an accrual basis including incremental payments required to align the prior year's cash basis of reporting with no taxes payable. Management along with our legal advisors believe the CRA has not properly applied the provisions of the Income Tax Act (Canada) that entitle income from a royalty to be included in taxable income on a cash basis and that the dispute will be resolved with no taxes payable by Harvest Energy Trust.

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

	Payments Due by Period						
	2009	2010	2011	2012	2013	Thereafter	Total
Debt repayments (1)	-	1,233,843	315,325	-	-	-	**1,549,168**
Debt interest payments(2)	80,507	95,436	82,256	60,838	44,549	27,299	**390,885**
Capital commitments(3)	39,535	-	-	-	-	-	**39,535**
Operating leases(4)	5,935	7,143	6,194	2,324	566	566	**22,728**
Pension contributions(5)	5,700	7,038	7,179	7,322	7,469	7,618	**42,326**
Transportation agreements(6)	2,675	2,678	952	551	189	-	**7,045**
Feedstock commitments(7)	246,159	-	-	-	-	-	**246,159**
Contractual obligations	**380,511**	**1,346,138**	**411,906**	**71,035**	**52,773**	**35,483**	**2,297,846**

(1) Assumes that the outstanding Convertible Debentures either convert at the holders' option for Units or are redeemed for Units at Harvest's option.
(2) Interest determined on bank loan balance using the rate effective at period end and by using the period 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 11].
(6) Relating to oil and natural gas pipeline transportation agreements.
(7) Relating to crude oil feedstock purchases and related transportation costs. North Atlantic has a Supply and Offtake Agreement with Vitol Refining S.A. This agreement, which continues on a monthly basis with a mutual six months termination notice period, provides that the ownership of substantially all crude oil feedstock and refined product inventory at the refinery be retained by Vitol Refining S.A. and that Vitol Refining S.A. will be granted the right and obligation to provide crude oil feedstock for delivery to the refinery, as well as the right and obligation to purchase substantially all refined products produced by the refinery.

15. Subsequent Events

Subsequent to March 31, 2009, Harvest declared a distribution of $0.05 per unit for Unitholders of record on April 22, 2009 and May 28, 2009.

16. Comparatives

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