Financial & Operating Highlights

The table below provides a summary of our financial and operating results for the three and nine month periods ended September 30, 2008 and 2007.

	Three Month Period Ended Sept 30			Nine Month Period Ended Sept 30		
($000s except where noted)	**2008**	2007	Change	**2008**	2007	Change
Revenue, net(1)	**1,597,195**	1,031,514	55%	**4,596,625**	3,190,476	44%
Cash From Operating Activities before changes in non-cash working capital and asset retirement obligations	**208,928**	136,208	53%	**577,770**	594,610	(3%)
Per Trust Unit, basic	**$ 1.36**	$ 0.94	45%	**$ 3.81**	$ 4.39	(13%)
Cash From Operating Activities	**133,493**	191,049	(30%)	**472,147**	553,315	(15%)
Per Trust Unit, basic	**$ 0.87**	$ 1.31	(34%)	**$ 3.11**	$ 4.09	(24%)
Per Trust Unit, diluted	**$ 0.84**	$ 1.22	(31%)	**$ 2.95**	$ 3.74	(21%)
Net Income (Loss)(2)	**295,788**	11,811	2,404%	**133,379**	87,909	52%
Per Trust Unit, basic	**$ 1.93**	$ 0.08	2,313%	**$ 0.88**	$ 0.65	35%
Per Trust Unit, diluted	**$ 1.73**	$ 0.08	2,063%	**$ 0.88**	$ 0.65	35%
Distributions declared	**138,511**	166,271	(17%)	**410,678**	465,598	(12%)
Distributions declared, per Trust Unit	**$ 0.90**	$ 1.14	(21%)	**$ 2.70**	$ 3.42	(21%)
Distributions declared as a percentage of Cash From Operating Activities before changes in non-cash working capital and asset retirement obligations	**66%**	122%	(56%)	**71%**	78%	(7%)
Distributions declared as a percentage of Cash From Operating Activities	**104%**	87%	17%	**87%**	84%	3%
Bank debt				**1,199,773**	1,205,119	0%
77/8% Senior Notes				**260,120**	241,628	8%
Convertible Debentures(3)				**824,771**	650,440	27%
Total long-term debt(3)				**2,284,664**	2,097,187	9%
Total assets				**5,659,227**	5,585,651	1%
UPSTREAM OPERATIONS						
Daily Production						
Light to medium oil (bbl/d)	**25,210**	27,401	(8%)	**25,362**	27,342	(7%)
Heavy oil (bbl/d)	**11,485**	14,217	(19%)	**12,182**	14,845	(18%)
Natural gas liquids (bbl/d)	**2,627**	2,219	18%	**2,575**	2,350	10%
Natural gas (mcf/d)	**93,628**	96,737	(3%)	**96,394**	98,682	(2%)
Total daily sales volumes (boe/d)	**54,926**	59,961	(8%)	**56,184**	60,984	(8%)
Operating Netback ($/boe)	**$ 60.38**	$ 28.69	110%	**$ 56.08**	$ 28.95	94%
Cash capital expenditures	**69,098**	73,323	(6%)	**188,337**	270,031	(30%)
DOWNSTREAM OPERATIONS						
Average daily throughput (bbl/d)	**99,127**	103,983	(5%)	**103,832**	111,052	(7%)
Aggregate throughput (mbbl)	**9,120**	9,566	(5%)	**28,449**	30,317	(6%)
Average Refining Margin (US$/bbl)	**$ 10.47**	$ 3.08	240%	**$ 8.38**	$ 10.57	(21%)
Cash capital expenditures	**17,199**	12,468	38%	**31,845**	27,222	17%

(1) Revenues are net of royalties.

(2) Net Income (Loss) includes a future income tax expense of $149.5 million and $32.5 million for the three and nine months ended Sept 30, 2008 respectively (future income tax recovery of $54.4 million and future tax expense of $123.3 million for the three and nine months ended Sept 30, 2007) and an unrealized net gain from risk management activities of $359.7 million and a net loss of $6.3 million for the three and nine months ended Sept 30, 2008 respectively (loss of $21.9 million and loss of $25.0 million for the three and nine months ended Sept 30, 2007).

(3) Includes current portion of Convertible Debentures.

Message to Unitholders

The third quarter of 2008 saw the organization continue its strong operational performance in both the upstream and downstream parts of our business. We continue to show good ongoing performance while preparing for potential significant growth opportunities in both our upstream business and downstream business.

In the upstream, we have attractive improved recovery opportunities and development drilling in many of our fields. These short and medium-term opportunities are complemented by longer-term opportunities in carbon dioxide (CO2) flooding and sequestration, coalbed methane, and oilsands development. In the downstream, our attractive debottleneck growth opportunities are complemented with a very attractive and large reconfiguration project. The unique feature of our longer-term opportunities is that they can be matured and progressed effectively with minimal cost, and then advanced quickly when capital is allocated to the project. We are under no requirement to proceed at this time on these projects so we can wait with little cost or loss of net present value while financial markets stabilize.

The strength of our overall asset base is demonstrated by the relative stability of our cashflows during the recent period of significant financial market upheaval. While our upstream business contributed less cashflow in the recent quarter, our downstream business offset that reduction with improved financial contribution. Our corporate cash flow before changes in non-cash working capital and asset retirement obligations totaled $208.9 million, ($1.36 per trust unit) for the quarter, resulting in distributions as a percentage of cash flow of 66%. This was our lowest payout ratio since the second quarter of 2007 and the second lowest payout ratio in the last 11 quarters dating back to 2005.

This financial performance, coupled with our expectations for the remainder of 2008 and early 2009 resulted in Harvest maintaining our current $0.30 per unit monthly distribution level for the months of November and December 2008 and January and February 2009. Over the next few months we will assess the changing economic environment that we are operating under with a view to assessing our optimal distribution strategy to create value for shareholders.

Upstream

Our operating cash flow from the upstream business segment was $296.5 million during the third quarter, driven largely by a strong oil price environment. Excluding the impact of an extended turnaround at a 3rd party operated gas plant in our Bashaw area, our average upstream volumes of 54,926 boe/d were on budget for the period.

We continued to execute our capital program in the third quarter, investing $69.1 million drilling 67 gross (34.7 net) wells which realized a 100% success rate. Year to date, we have now drilled 165 gross (102.1 net) wells with a 100% success rate. Our drilling activities were primarily focused in southeast Saskatchewan where we drilled 18 wells and west central Alberta where we continue with exploration and development success on multi-zone, liquids rich natural gas plays. We are now utilizing multi-stage fracturing technology in a number of areas to increase recovery from horizontal wells in tight light oil and natural gas plays. This technology is expected to result in about three times the recovery at four times the initial rate of an unstimulated wellbore.

In addition to the near term impacts realized by drilling & optimization, our teams are also very focused on longer term opportunities with Enhanced Oil Recovery (EOR) projects. The Hay River waterflood enhancement project completed in the first quarter continues to show excellent results with production contribution exceeding our expectations. We now expect this area to be very active for our winter 2008/2009 drilling season in light of the improved reservoir response. In the third quarter, we commenced injection at our Suffield project and are pleased with early time results. Our enhanced waterflood project for Bellshill is proceeding well and we expect first enhanced injection in mid November. For our Wainwright polymer flood, we began construction of the mixing skid in the second quarter and anticipate that we will be injecting the first slug of polymer into the reservoir early in the new year. These projects are very economic at current oil prices and reflective of the type of enhanced recovery we can do at many of our fields. We expect to continue enhanced recovery projects at other fields in 2009 and future years.

On longer-term projects, approximately 40% of our asset base outside the oilsands is considered amenable to CO2 flooding. With an incremental recovery potential of 10% or more of this approximately 800 million barrel original oil in place asset base, we could increase our reserves significantly through application of this technology. In the oilsands areas of the province, we currently have about 47,000 net acres of leases with about 1 billion barrels of resource. In the Cold Lake oilsands region, we produce about 300 barrels per day from this resource. In the Peace River oilsands region, we plan to drill a further two stratigraphic tests in 2009 to delineate the regional extent of the resource base and test oil quality. In coalbed methane (CBM), we are producing from about 10 gross wells in the Horseshoe Canyon formation. Our resource base of CBM assets is extensive and estimated to contain about 1 trillion net cubic feet of natural gas. We expect to continue increasing production while considering the optimal development strategy.

The sudden drop in natural gas prices and world oil prices in the third quarter reminds us of the need to be highly efficient in our operations and selective in our disciplined capital investment. We have an asset base with considerable short-term opportunity that is highly economic at current oil prices and substantial longer-term opportunity that can be developed as capital is available. We see great opportunity in the asset base.

Downstream

In the third quarter, our financial results from the downstream business were very strong and substantially improved in comparison to the second quarter of 2008 or the third quarter of 2007. We were very pleased with our operational and our financial performance.

Throughout the third quarter, we had very good operational performance with on-stream factors of 100% for our major processing units. As distillate products were particularly valuable in the third quarter, we used operational procedures and crude oil selection to maximize our production of distillates. Consistent with the strategy for all of our assets, we strive to continuously improve the performance of these operations. This includes operational improvements that can be undertaken to improve gross margins, but also a focus on cost reduction and efficiency projects. We are unwavering in our commitment to control operating costs and taking a prudent approach to all capital investment opportunities to ensure the maximum return on our invested dollars.

The increase in cashflow from the downstream business relative to the second quarter was driven by significantly improved margins on heavy fuel oil and strong margins continuing on distillate products such as diesel and jet fuel partially offset by a decrease in margins for gasoline. Distillate margins in the third quarter benefited from strong global demand for distillate products where supply and demand balances were tight. We expect excellent distillate margins to continue as winter approaches with the typical seasonal strengthening. Gasoline margins were volatile in the third quarter with low margins early in the quarter and stronger margins later as refinery runs were reduced to balance demand and hurricane-related refinery outages in the Gulf Coast led to low inventories and improved margins.

Our refining business has identified a portfolio of about $300 million of highly economic (40-55% rate of return) debottleneck projects. In 2009, we will be progressing on some of our highly economic debottleneck projects that have been defined over the past year. As well, we expect to advance our planning on other similar growth projects which can be undertaken in future years.

At the refinery we have an attractive $2 billion major reconfiguration project which has an expected rate of return of approximately 20-30%. This major project would expand capacity by about 75,000 barrels per day while reducing the cost of the crude oil that we process and upgrading 100% of the heavy fuel oil that we produce to highly valued distillate products. It appears to be an excellent project but one that we do not need to do to stay competitive. In light of current market conditions, we have elected to defer this project to when financial markets are more supportive.

Corporate

The financial drivers of our performance in the third quarter were very volatile. The third quarter saw a sharp drop in the price of crude oil which has continued into the fourth quarter as well. At the beginning of the third quarter, the price of WTI light sweet crude was approximately US$140/bbl but has recently been about US$65/bbl. The drop in natural gas prices was also significant. These drops have reduced the profitability of all upstream businesses including our own. The full impact however of the drop has been mitigated somewhat by a drop in the value of the Canadian dollar and Harvest's price risk management program. Although our risk management contracts did limit our full participation in the strong oil price environment earlier in 2008, they provide downside protection through June of 2009. As well, we have seen the benefit of a diversified asset base as our downstream business has performed better and offset the reduction in crude oil and natural gas prices. While uncertainty in the global financial markets and a pessimistic economic outlook have led to a drop in share price, we have seen the benefit of our diversified asset base with cashflow improving versus the second quarter.

Although conditions in credit markets are volatile and unstable, we have no near term maturities on our existing debt and are well within our covenants on the bank debt, senior notes and convertible debentures. Currently we have approximately $400mm of undrawn capacity on our committed bank line. This committed financing provides the certainty to weather the current economic environment and be positioned to thrive as markets improve.

With the strong cashflow, we are pleased to be able to maintain our distribution at $0.30/month and declare the distribution for each of the next 4 months. Over that period, we will continue to review the changing economic and financial market conditions that we find ourselves in today with a view to making a change in distribution policy if warranted at that time.

During the third quarter, we continued to focus efforts on maintaining high standards of environmental, health & safety (EH&S) performance. As a result of our commitment to good EH&S practices in both the upstream and downstream business segments, we continue to be an industry leader in this area.

2009 Budget

We are also please to announce the approval of our 2009 budget. We create value through the entrepreneurial growth of our assets and the efficient development and operation of those assets. Our unique asset offers opportunities that are highly economic at today's prices along with longer-term opportunities that can be exploited over time.

- **2009 Upstream** - We are budgeting $260 million in annual capital expenditures, weighted towards capturing value of the near-term drilling opportunities on our oil and liquids-rich natural gas properties. We are also continuing to advance our unconventional asset strategy in tight gas, tight oil, oil sands and tertiary enhanced recovery. Based on this level of capital spending, we anticipate 2009 production volumes to average between 52,000 and 53,000 barrels per day, with operating costs of approximately $15/boe. Royalties as a percentage of 2008 revenue are expected to be consistent with our recent historical rates of approximately 17%.
- **2009 Downstream** - We are budgeting $62 million in annual capital expenditures, with approximately one-half directed towards discretionary projects. With planned turnarounds during the year, we anticipate 2009 refinery throughput to average approximately 110,000 bbl/d. Our 2009 per barrel operating costs are expected to be improved relative to 2008 due to anticipated lower purchased energy costs and higher throughput volumes.

Looking forward, we continue to be encouraged by the fundamentals for the upstream and downstream oil businesses that we are active in. Given the characteristics of our assets, we feel confident that we can deliver long-life sustainable performance from our asset base while being opportunistic in timing the development of the identified opportunities that we have on those assets. This creates the opportunity for ongoing yield for investors along with the potential for capital appreciation. With our integrated business model, long life assets and strong technical team, Harvest is truly driving our future for Sustainable Growth.

In closing, I would like to thank all of our Unitholders for your support as we weather the challenging times in the financial markets and enjoy the strong fundamentals that remain in our upstream and downstream combined asset base.

As always, I would encourage you to contact us with your feedback and questions about 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, 2007 and 2006, our MD&A for the year ended December 31, 2007 as well as our interim consolidated financial statements and notes for the three and nine month periods ended September 30, 2008 and 2007. The information and opinions concerning our future outlook are based on information available at November 12, 2008.

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.

In this MD&A, we use certain financial reporting measures that are commonly used as benchmarks within the petroleum and natural gas industry such as Earnings From Operations, Cash General and Administrative Expenses and Operating Netbacks and with respect to the refining industry, Earnings from Operations and Gross Margin which are each defined in this MD&A. These measures are not defined under Canadian generally accepted accounting principles ("GAAP") and should not be considered in isolation or as an alternative to conventional GAAP measures. Certain of these measures are not necessarily comparable to a similarly titled measure of another issuer. When these measures are used, they are defined as "Non-GAAP measures" and should be given careful consideration by the reader. Please refer to the discussion under the heading "Non-GAAP Measures" at the end of this MD&A for a detailed discussion of these measures.

FORWARD-LOOKING INFORMATION

This MD&A highlights significant business results and statistics from our consolidated financial statements for the three and nine month periods ended September 30, 2008 and the accompanying notes thereto. In the interest of providing our Unitholders and potential investors with information regarding Harvest, including our assessment of our future plans and operations, this MD&A contains forward-looking statements that involve risks and uncertainties. Such risks and uncertainties include, but are not limited to, risks associated with conventional petroleum and natural gas operations; risks associated with refining and marketing operations, the volatility in commodity prices and currency exchange rates; risks associated with realizing the value of acquisitions; general economic, market and business conditions; changes in environmental legislation and regulations; the availability of sufficient capital from internal and external sources and such other risks and uncertainties described from time to time in our regulatory reports and filings made with securities regulators.

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

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

Consolidated Financial and Operating Highlights – Third Quarter 2008

- Cash from operating activities was $133.5 million during the Third Quarter of 2008 and $191.0 million for the same period in the prior year compared to the more traditional non-GAAP measure of cash from operating activities before changes in non-cash working capital and settlement of asset retirement obligations of $208.9 million for the Third Quarter of 2008 and $136.2 million for the same period in 2007.

- During the Third Quarter, monthly distributions were maintained at $0.30 per Trust Unit representing a payout ratio of 104% of cash from operating activities and 66% of cash from operating activities before changes in non-cash working capital and settlement of asset retirement obligations.
- Upstream operating cash flow of $296.5 million as compared to $149.7 million in the prior year reflects the strength of commodity prices in 2008 with average daily production of 54,926 boe/d as compared to 59,961 boe/d in the prior year.
- Upstream capital spending of $69.1 million drilling 67 wells with a success ratio of 100% including 18 wells in southeast Saskatchewan and 8 horizontal wells in the Lloydminster/Hayter area.
- Downstream operating cash flow of $47.2 million reflecting reliable refinery operations with reduced levels of throughput enhancing profitability by minimizing the volume of high sulphur fuel oil produced.
- Balance sheet liquidity maintained with $400 million of undrawn committed credit lines available and no material debt maturities prior to April 2010.

SELECTED INFORMATION

The table below provides a summary of our financial and operating results for three and nine month periods ended September 30, 2008 and 2007.

	Three Months Ended September 30			Nine Months Ended September 30		
($000s except where noted)	**2008**	2007	Change	**2008**	2007	Change
Revenue, net[1]	**1,597,195**	1,031,514	55%	**4,596,625**	3,190,476	44%
Cash From Operating Activities before changes in non-cash working capital and asset retirement obligations	**208,982**	136,208	53%	**577,770**	594,610	(3%)
Per Trust Unit, basic	**$ 1.36**	$ 0.94	45%	**$ 3.81**	$ 4.39	(13%)
Cash From Operating Activities	**133,493**	191,049	(30%)	**472,147**	553,315	(15%)
Per Trust Unit, basic	**$ 0.87**	$ 1.31	(34%)	**$ 3.11**	$ 4.09	(24%)
Per Trust Unit, diluted	**$ 0.84**	$ 1.22	(31%)	**$ 2.95**	$ 3.74	(21%)
Net Income[2]	**295,788**	11,811	2,404%	**133,379**	87,909	52%
Per Trust Unit, basic	**$ 1.93**	$ 0.08	2,313%	**$ 0.88**	$ 0.65	35%
Per Trust Unit, diluted	**$ 1.73**	$ 0.08	2,063%	**$ 0.88**	$ 0.65	35%
Distributions declared	**138,511**	166,271	(17%)	**410,678**	465,598	(12%)
Distributions declared, per Trust Unit	**$ 0.90**	$ 1.14	(21%)	**$ 2.70**	$ 3.42	(21%)
Distributions declared as a percentage Of Cash From Operating Activities	**104%**	87%	17%	**87%**	84%	3%
Bank debt				**1,199,773**	1,205,119	0%
7$^{7/8}$% Senior Notes				**260,120**	241,628	8%
Convertible Debentures[3]				**824,771**	650,440	27%
Total long-term debt[3]				**2,284,664**	2,097,187	9%
Total assets				**5,659,227**	5,585,651	1%
UPSTREAM OPERATIONS						
Daily Production						
Light to medium oil (bbl/d)	**25,210**	27,401	(8%)	**25,362**	27,342	(7%)
Heavy oil (bbl/d)	**11,485**	14,217	(19%)	**12,182**	14,845	(18%)
Natural gas liquids (bbl/d)	**2,627**	2,219	18%	**2,575**	2,350	10%
Natural gas (mcf/d)	**93,628**	96,737	(3%)	**96,394**	98,682	(2%)
Total daily sales volumes (boe/d)	**54,926**	59,961	(8%)	**56,184**	60,984	(8%)
Operating Netback ($/boe)	**$ 60.38**	$ 28.69	110%	**$ 56.08**	$ 28.95	94%
Cash capital expenditures	**69,098**	73,323	(6%)	**188,337**	270,031	(30%)
DOWNSTREAM OPERATIONS						
Average daily throughput (bbl/d)	**99,127**	103,983	(5%)	**103,832**	111,052	(7%)
Aggregate throughput (mbbl)	**9,120**	9,566	(5%)	**28,449**	30,317	(6%)
Average Refining Margin (US$/bbl)	**$ 10.47**	$ 3.08	240%	**$ 8.38**	$ 10.57	(21%)
Cash capital expenditures	**17,199**	12,468	38%	**31,845**	27,222	17%

(4) Revenues are net of royalties.
(5) Net Income includes a future income tax expense of $149.5 million and $32.5 million for the three and nine months ended September 30, 2008 respectively (future income tax recovery of $54.4 million and future tax expense of $123.3 million for the three and nine months ended September 30, 2007) and an unrealized net gain from risk management activities of $359.7 million and a net loss of $6.3 million for the three and nine months ended September 30, 2008 respectively (loss of $21.9 million and loss of $25.0 million for the three and nine months ended September 30, 2007).
(6) Includes current portion of Convertible Debentures.

REVIEW OF OVERALL PERFORMANCE

Harvest is an integrated energy trust with our petroleum and natural gas operations focused on the operation and further development of assets in western Canada ("upstream operations") and our refining and marketing business focused on the safe operation of a medium gravity sour crude hydrocracking refinery and a retail and wholesale petroleum marketing business both located in the Province of Newfoundland and Labrador ("downstream operations").

During the Third Quarter of 2008, cash from operating activities of $133.5 million is comprised of cash flow contributions of $296.5 million and $47.2 million from the upstream and downstream operations, respectively, offset by a $72.4 million increase in working capital requirements, $94.5 million of cash settlements from our risk management activities and $43.2 million of financing and other costs. The year-over-year $57.6 million reduction in cash flow from operating activities is primarily attributed to a $130.2 million change in working capital requirements, a $92.7 million increase in cash settlements from our price risk management contracts and a $51.7 million drop in realized foreign exchange gains offset by a $146.8 increase in the contribution from our upstream operations along with a $70.6 million improvement from our downstream operations.

Our monthly distributions of $0.30 per Trust Unit during the Third Quarter represent 104% of our cash from operating activities and 66% of cash from operating activities before changes in non-cash working capital and settlement of asset retirement obligations. We have declared monthly distributions of $0.30 per Trust Unit for November and December of 2008 as well as January and February of 2009. Unitholder participation in our distribution reinvestment programs has generated $35.2 million of equity capital in the Third Quarter reflecting a 25% average level of participation.

Cash flow provided from our upstream operations totaled $296.5 million during the Third Quarter of 2008 as compared to $149.7 million in the prior year. The primary factors associated with the improvement were the strength of Canadian crude oil prices during 2008 which reflected a 57% increase in the WTI benchmark price, a stable Canadian dollar relative to the US dollar and much tighter heavy oil differentials. During the quarter, our average realized price of $90.15 per boe was 3% lower than the $93.29 in the prior quarter and significantly improved compared to $54.15 in the prior year while our average daily production of 54,926 boe/d during the quarter and 55,574 in the Second Quarter of 2008 reflects a natural decline from 59,961 in the Third Quarter of 2007. Midway through the Third Quarter of 2008, we bolstered our production with the acquisition of light/medium oil and natural gas assets producing approximately 2,650 boe/d. Our operating costs averaged $14.51 per boe during the quarter essentially unchanged from $14.45 in the Second Quarter of 2008 with lower spending spread over a reduced volume during the Third Quarter of 2008. Our netback averaged $60.38 per boe during the quarter as compared to $62.99 in the Second Quarter of 2008 and $28.69 in the Third Quarter of the prior year.

Cash flow from our downstream operations of $47.2 million was a substantial improvement over the breakeven performance in the prior quarter and the cash flow deficiency of $23.4 million in the Third Quarter of 2007. As compared with the prior year, the current quarter reflects a substantial improvement in distillate margins along with an improved yield of distillate products and a reduced yield of lower valued high sulphur fuel oil ("HSFO"). Our average cost of crude oil feedstock relative to the WTI benchmark price was also much improved in the current quarter as compared to the prior year. Offsetting these improvements was a much weaker margin for gasoline products as well as a higher cost for purchased energy to provide heat to the refining processes. During the quarter, our average refining margin was US$10.47 per barrel of throughput, a US$4.81 improvement over the prior quarter and a US$7.39 improvement over the Third Quarter of the prior year. While we achieved very reliable refinery operations with no unplanned disruptions, our throughput averaged 99,127 bbls/d during the quarter as crude oil feedstock was reduced to minimize the production of HSFO as compared to throughput of 103,983 bbls/d in the Third Quarter of the prior year when throughput was constrained as the refinery entered a significant turnaround.

At the end of September 2008, we had $400.2 million of available credit under our $1.6 billion Extendible Revolving Credit Facility with our bank debt to annualized earnings before interest, taxes, depreciation and amortization ("EBITDA") ratio at 1.5 times.

Business Segments

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

	Three Months Ended September 30					
	2008			2007		
(in $000s)	**Upstream**	**Downstream**	**Total**	Upstream	Downstream	Total
Revenue(1)	**382,297**	**1,214,898**	**1,597,195**	241,902	789,612	1,031,514
Earnings (Loss) From Operations(2)	**195,380**	**30,509**	**225,889**	41,026	(39,610)	1,416
Capital expenditures	**69,098**	**17,199**	**86,297**	73,323	12,468	85,791
Total assets(3)	**3,982,397**	**1,670,107**	**5,659,227**	4,085,988	1,499,663	5,585,651

	Nine Months Ended September 30					
	2008			2007		
(in $000s)	**Upstream**	**Downstream**	**Total**	Upstream	Downstream	Total
Revenue(1)	**1,092,182**	**3,504,443**	**4,596,625**	716,432	2,474,044	3,190,476
Earnings From Operations(2)	**507,059**	**22,556**	**529,615**	112,726	154,924	267,650
Capital expenditures	**188,337**	**31,845**	**220,182**	270,031	27,222	297,253
Total assets(3)	**3,982,397**	**1,670,107**	**5,659,227**	4,085,988	1,499,663	5,585,651

(1) Revenues are net of royalties.
(2) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.
(3) Total assets on a consolidated basis as at September 30, 2008 include $6.7 million (2007 - $22.2 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

Third Quarter Highlights

- Operating cash flow of $296.5 million, an improvement of $146.8 million over the Third Quarter of the prior year, reflecting the year-over-year strength of crude oil prices as well as a tightening of quality differentials.
- Average daily production of 54,926 boe/d as compared to production of 55,574 boe/d in the Second Quarter of 2008 reflecting our stable production of light to medium oil and natural gas.
- Aggregate operating cost expenditures were approximately 9% lower than the Third Quarter of the prior year while our unit operating costs of $14.51 are essentially unchanged from $14.54 in the prior year as the average daily production in the Third Quarter of 2007 was approximately 5,000 boe/d greater than the Third Quarter of 2008.
- Operating netback of $60.38 per boe, representing a $31.69 (110%) increase over the prior year, attributed primarily to substantially higher commodity prices.
- Completed two acquisitions for aggregate cash consideration of $167.6 million, acquiring 2,650 boe/d of production representing an average cost per flowing barrel of approximately $63,000 comprised of 1,645 bbls/d of light oil and 6,200 mcf/d of natural gas.
- Capital spending of $69.1 million included the drilling of 67 wells (34.7 on a net basis) with a 100% success rate which brings the total wells drilled in 2008 to 165 (102.1 net wells)

Summary of Financial and Operating Results

(in $000s except where noted)	Three Months Ended September 30 **2008**	2007	Change	Nine Months Ended September 30 **2008**	2007	Change
Revenues	**455,565**	298,708	53%	**1,304,664**	876,435	49%
Royalties	**(73,268)**	(56,806)	29%	**(212,482)**	(160,003)	33%
Net revenues	**382,297**	241,902	58%	**1,092,182**	716,432	52%
Operating expenses	**73,314**	80,189	(9%)	**218,729**	224,818	(3%)
General and administrative	**2,148**	4,159	(48%)	**26,766**	30,324	(12%)
Transportation and marketing	**3,855**	3,412	13%	**10,232**	9,599	7%
Depreciation, depletion, amortization and accretion	**107,600**	113,116	(5%)	**329,396**	338,965	(3%)
Earnings From Operations(1)	**195,380**	41,026	376%	**507,059**	112,726	350%
Cash capital expenditures (excluding acquisitions)	**69,098**	73,323	(6%)	**188,337**	270,031	(30%)
Property and business acquisitions, net of dispositions	**132,130**	139,378	(5%)	**127,581**	148,530	(14%)
Daily sales volumes						
Light to medium oil (bbl/d)	**25,210**	27,401	(8%)	**25,362**	27,342	(7%)
Heavy oil (bbl/d)	**11,485**	14,217	(19%)	**12,182**	14,845	(18%)
Natural gas liquids (bbl/d)	**2,627**	2,219	18%	**2,575**	2,350	10%
Natural gas (mcf/d)	**93,628**	96,737	(3%)	**96,394**	98,682	(2%)
Total (boe/d)	**54,926**	59,961	(8%)	**56,184**	60,984	(8%)

(1) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

Commodity Price Environment

Benchmarks	Three Months Ended September 30 **2008**	2007	Change	Nine Months Ended September 30 **2008**	2007	Change
West Texas Intermediate crude oil (US$ per barrel)	**117.98**	75.38	57%	**113.29**	66.19	71%
Edmonton light crude oil ($ per barrel)	**121.59**	79.66	53%	**114.94**	72.89	58%
Bow River blend crude oil ($ per barrel)	**105.12**	55.79	88%	**95.74**	52.20	83%
AECO natural gas daily ($ per mcf)	**7.74**	5.18	49%	**8.62**	6.55	32%
Canadian / U.S. dollar exchange rate	**0.960**	0.957	0%	**0.982**	0.907	8%

During the Third Quarter 2008 the average West Texas Intermediate ("WTI") benchmark price increased 57% over the Third Quarter 2007 and for the nine months ended September 30, 2008 the average price was 71% higher than in the prior year. The average Edmonton light crude oil price ("Edmonton Par") has also increased over the past twelve months to average $121.59 during the Third Quarter, an increase of 53% over the same period of the prior year and $114.94/bbl for the nine months ended September 30, 2008, an increase of 58% over the prior year. On a year-to-date basis, the increase in value of Edmonton Par throughout 2008 has been less dramatic than that of WTI due to the strength of the Canadian dollar relative to the US dollar in 2008, which has increased by 8% for the nine months ended September 30 relative to the first nine months of the prior year.

Heavy oil differentials fluctuate based on a combination of factors including the level of heavy oil inventories, pipeline capacity to deliver heavy crude to U.S. markets and the seasonal demand for heavy oil. During the Third Quarter of 2008, the Bow River heavy oil differential relative to Edmonton Par tightened to an average of 13.5% compared to 30.0% in the Third Quarter of 2007. During the nine months ended September 30, 2008, heavy oil differentials have been consistently tighter than the first nine months of the prior year due to reduced supply due to pipeline disruptions early in the year coupled with production shortfalls and strong demand during the following spring and summer months.

	2008			2007				2006
Differential Benchmarks	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1	Q4
Bow River Blend differential to Edmonton Par	13.5%	17.1%	20.2%	34.2%	30.0%	29.4%	25.4%	30.3%

Compared to the prior year, the average AECO natural gas price was 49% and 32% higher during the three and nine months ended September 30, 2008, respectively. Natural gas prices have strengthened in 2008 relative to 2007 due to a general strengthening of commodity prices.

Realized Commodity Prices(1)

The following table summarizes our average realized price by product for the three and nine month periods ended September 30, 2008 and 2007.

	Three Months Ended September 30			Nine Months Ended September 30		
	2008	2007	Change	**2008**	2007	Change
Light to medium oil ($/bbl)	**110.70**	68.10	63%	**102.15**	62.02	65%
Heavy oil ($/bbl)	**99.21**	48.95	103%	**87.75**	45.70	92%
Natural gas liquids ($/bbl)	**88.17**	61.63	43%	**85.16**	57.55	48%
Natural gas ($/mcf)	**8.44**	5.67	49%	**9.16**	7.10	29%
Average realized price ($/boe)	**90.15**	54.15	66%	**84.75**	52.64	61%

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

During the three and nine months ended September 30, 2008, our average realized price was 66% and 61% higher, respectively, than the comparable periods in 2007 with every product realizing a higher average price than in the prior year.

Our realized price for light to medium oil sales increased 63% in the Third Quarter of 2008 compared to the Third Quarter of 2007, reflecting the 53% increase in Edmonton Par pricing coupled with improved quality differentials realized on our light to medium oil production relative to the Edmonton Par price. During the nine months ended September 30, 2008, our realized price for light to medium oil sales was 65% higher than the same period in 2007 which also reflects the 58% increase in Edmonton Par pricing over the prior year as well as improved quality differentials.

Harvest's heavy oil price increased 103% in the Third Quarter of 2008 relative to the Third Quarter of 2007, reflecting the 88% increase in the average posted Bow River price for the same periods. Similarly, our average heavy oil price for the year-to-date is 92% higher than the prior year, reflecting the increase of 83% in the Bow River posted price for the first nine months of 2008 relative to the first nine months of 2007. Harvest realized an increased heavy oil price relative to the Bow River posted price in the Third Quarter as production shortfalls and increased refinery demand for heavier grades of oil put upward pressure on pricing.

The average realized price for our natural gas production was 49% higher in the Third Quarter of 2008 as compared to the Third Quarter of 2007 reflecting the same increase in AECO daily pricing over the same period, while during the first nine months of 2008, we realized a natural gas sales price that was 29% higher than in the prior year, reflecting the AECO daily pricing increase of 32%.

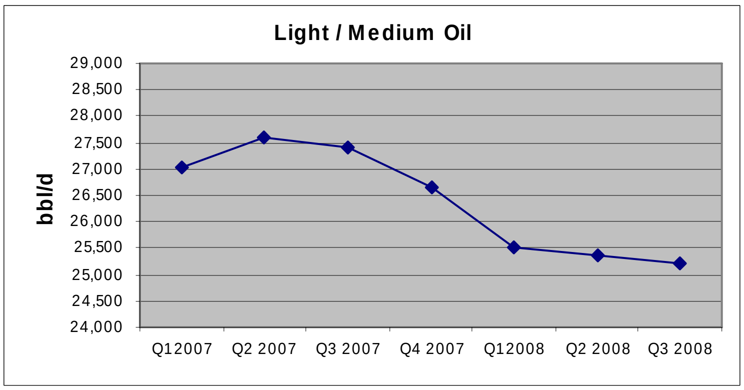
Sales Volumes

The average daily sales volumes by product were as follows:

	Three Months Ended September 30				
	2008		2007		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)(1)	**25,210**	**46%**	27,401	46%	(8%)
Heavy oil (bbl/d)	**11,485**	**21%**	14,217	24%	(19%)
Natural gas liquids (bbl/d)	**2,627**	**5%**	2,219	4%	18%
Total liquids (bbl/d)	**39,322**	**72%**	43,837	74%	(10%)
Natural gas (mcf/d)	**93,628**	**28%**	96,737	26%	(3%)
Total oil equivalent (boe/d)	**54,926**	**100%**	59,961	100%	(8%)

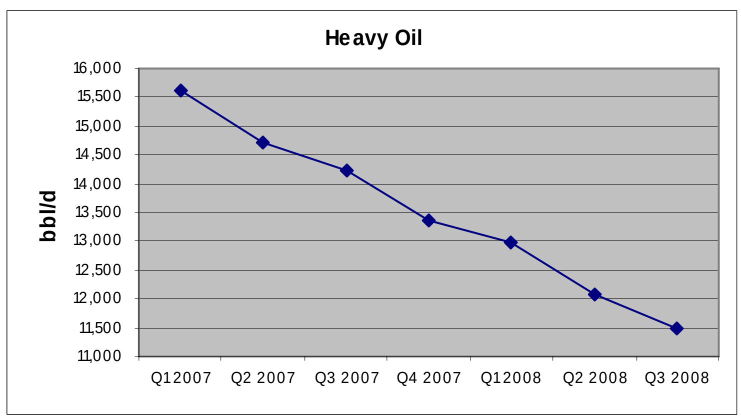
	Nine Months Ended September 30				
	2008		2007		
	Volume	Weighting	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)(1)	**25,362**	**45%**	27,342	45%	(7%)
Heavy oil (bbl/d)	**12,182**	**22%**	14,845	24%	(18%)
Natural gas liquids (bbl/d)	**2,575**	**5%**	2,350	4%	10%
Total liquids (bbl/d)	**40,119**	**72%**	44,537	73%	(10%)
Natural gas (mcf/d)	**96,394**	**28%**	98,682	27%	(2%)
Total oil equivalent (boe/d)	**56,184**	**100%**	60,984	100%	(8%)

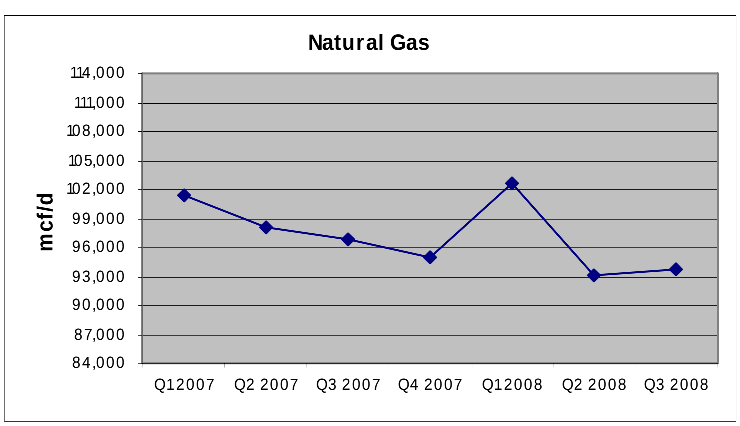
(1) Harvest classifies our oil production, except that produced from Hay River, as light to medium and heavy according to NI 51-101 guidance. The oil produced from Hay River has an average API of 24° (medium grade) and is classified as a light to medium oil, however, it benefits from a heavy oil royalty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



Harvest's Third Quarter 2008 light/medium oil production was 25,210 bbl/d, a 2,191 bbl/d or 8% reduction from the same period in the prior year, and a reduction of 155 bbl/d or 1% from the Second Quarter of 2008. The 8% reduction is mainly attributed to steeper than expected declines experienced as the initial flush production from wells completed in early 2007 stabilized. In the Third Quarter of 2008, light/medium production has continued to remain relatively consistent with the two prior quarters as increased water cuts and production lost to downtime have been substantially offset by new wells and the production from two acquisitions completed during the quarter. Production at our largest area, Hay River, has remained constant over the past two quarters reflecting our First Quarter initiatives to increase water injection and improve recovery. Relative to the first nine months of 2007, Harvest's year-to-date light/medium oil production has declined by 7% due to steeper than anticipated declines throughout 2007 and a lower level of drilling activity in 2008.

Our heavy oil production has decreased steadily over the past twelve months resulting in a 19% reduction with Third Quarter 2008 production of 11,485 bbl/d as compared to 14,217 bbl/d in the Third Quarter of 2007. This reduction is largely the result of increased water cuts experienced on our larger producing wells in the west central Saskatchewan and Lloydminster areas coupled with normal declines elsewhere. In the Third Quarter of 2008, we continued normal decline. On a year-to-date basis, cold and wet weather related operational problems, as well as shut-ins to accommodate nearby drilling, contributed to the decrease in volumes from 14,845 bbl/d during the first nine months of 2007 to 12,182 bbl/d during the first nine months of 2008.





Our Third Quarter of 2008 natural gas production decreased by 3% relative to the Third Quarter of 2007, averaging 93,628 mcf/d. Relative to the Second Quarter of 2008, our Third Quarter natural gas production has increased by 1%, primarily due to the incremental production associated with the acquisitions completed during the Third Quarter. Relative to the Third Quarter of the prior year our natural gas production has encountered disruptions from various third party processing facility turnarounds, which has been partially offset by flush production from new wells drilled early in 2008 which have since stabilized. Harvest's 2008 year-to-date production is 2% lower than the same period in 2007 due to continued declines and production disruptions throughout the Fourth Quarter of 2007 and Second Quarter 2008 offset by incremental production resulting from our 2008 winter drilling program and acquisitions completed in the Third Quarter of 2008.

Revenues

	Three Months Ended September 30			Nine Months Ended September 30		
(000s)	**2008**	2007	Change	**2008**	2007	Change
Light to medium oil sales	**$ 256,744**	$ 171,674	50%	**$ 709,825**	$ 462,964	53%
Heavy oil sales	**104,826**	64,026	64%	**292,883**	185,196	58%
Natural gas sales	**72,690**	50,424	44%	**241,873**	191,357	26%
Natural gas liquids sales and other	**21,305**	12,584	69%	**60,083**	36,918	63%
Total sales revenue	**455,565**	298,708	53%	**1,304,664**	876,435	49%
Royalties	**(73,268)**	(56,806)	29%	**(212,482)**	(160,003)	33%
Net Revenues	**$ 382,297**	$ 241,902	58%	**$ 1,092,182**	$ 716,432	52%

Our revenue is impacted by changes to production volumes, commodity prices and currency exchange rates. Third Quarter of 2008 total sales revenue of $455.6 million is $156.9 million higher than the same period in the prior year, of which $182.2 million is attributed to higher realized prices offset by a $25.3 million negative variance in respect of lower production volumes. The price increase reflects the 53% increase in Edmonton Par pricing and 49% in AECO natural gas pricing in the Third Quarter of 2008 as compared to the Third Quarter of 2007, while our decreased production volume is attributed to the higher than anticipated decline rates experienced from recently completed wells coupled with various operational difficulties and a reduction in 2008 capital spending. On a year-to-date basis, our total sales revenue of $1,304.7 million is $428.2 million higher than for the comparable period in 2007, comprised of $493.0 million of additional revenue attributed to higher prices offset by a reduction in revenue of $64.8 million resulting from decreased production volumes.

Light to medium oil sales revenue for the Third Quarter of 2008 was $85.1 million higher than in the comparative period due to a $98.8 million favourable price variance offset by a $13.7 million unfavourable volume variance. The price variance reflects a 53% increase in Edmonton par pricing relative to the Third Quarter of the prior year plus improved differentials, while the negative volume variance reflects normal declines coupled with lower drilling activity in the winter of 2008 as compared to the prior year. For the nine months ended September 30, 2008, light to medium oil sales revenue was $246.9 million higher than the prior year-to-date, attributed to $278.8 million in increased revenues resulting from increased commodity pricing offset by a $31.9 million reduction due to a decline in production.

Third Quarter of 2008 heavy oil sales revenue of $104.8 million was $40.8 million higher than in the prior year due to a $53.1 million favourable price variance resulting from a 16.5% improvement in heavy oil differentials relative to the prior year coupled with the impact of the 57% increase in WTI, offset by a $12.3 million unfavourable volume variance reflecting a natural decline rate. The same factors apply to the variances in the first nine months of 2008 relative to 2007, where heavy oil sales revenue has increased by $107.7 million resulting from a favourable price variance of $140.3 million offset by an unfavorable volume variance of $32.6 million.

Natural gas sales revenue increased by $22.3 million in the Third Quarter of 2008 compared to the same period in 2007 due to a $23.9 million favourable price variance offset by a $1.6 million unfavourable volume variance. The favourable price variance reflects the $2.77/mcf increase in our realized natural gas prices resulting from a 49% increase in the AECO daily price relative to the prior year. During the first nine months of 2008, natural gas sales revenue was $50.5 million higher than the first nine months of the prior year, resulting from increased revenue of $54.3 million attributed to the increase in AECO pricing of 32% offset by a reduction in revenue of $3.8 million resulting from lower volumes.

In the Third Quarter of 2008, natural gas liquids and other sales revenue increased by $8.7 million compared to the Third Quarter of the prior year resulting from a $6.4 million favourable price variance and a $2.3 million favourable volume variance. Similarly, year-to-date natural gas liquids and other sales revenues increased by $23.2 million compared to the first nine months of 2007 resulting from a $19.5 million favourable price variance coupled with a $3.7 million favourable volume variance. Generally, the natural gas liquids volume variance will be aligned with our production of natural gas while the price variances will be aligned with the prices realized for our oil production.

Royalties

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

For the Third Quarter of 2008 net royalties as a percentage of gross revenue were 16.1% (19.0% in the Third Quarter of 2007) and aggregated to $73.3 million (2007 - $56.8 million). Our royalty rate for the Third Quarter of 2008 was slightly lower than the expected rate of 17% primarily due to reductions in freehold mineral taxes. Our royalties for the first nine months of 2008 were $212.5 million, resulting in a rate of 16.3% compared to $160.0 million and a rate of 18.3%, respectively, for the first nine months of 2007 as the prior year rate had increased in respect of a one-time adjustment of additional crown royalties that were assessed on our Hay River property.

Operating Expenses

	Three Months Ended September 30				
	2008		2007		Per BOE
(000s except per boe amounts)	**Total**	**Per BOE**	Total	Per BOE	Change
Operating expense					
Power and fuel	**$ 18,622**	**$ 3.69**	$ 19,569	$ 3.55	4%
Well Servicing	**14,474**	**2.86**	15,621	2.83	1%
Repairs and maintenance	**13,356**	**2.64**	13,852	2.51	5%
Lease rentals and property taxes	**6,548**	**1.30**	6,032	1.09	19%
Processing and other fees	**2,629**	**0.52**	3,373	0.61	(15%)
Labour – internal	**6,314**	**1.25**	5,489	1.00	25%
Labour – contract	**4,455**	**0.88**	3,861	0.70	26%
Chemicals	**3,115**	**0.62**	3,004	0.54	15%
Trucking	**2,664**	**0.53**	2,781	0.50	6%
Other	**1,137**	**0.22**	6,607	1.21	(82%)
Total operating expense	**$ 73,314**	**$ 14.51**	$ 80,189	$ 14.54	0%
Transportation and marketing expense	**$ 3,855**	**$ 0.76**	$ 3,412	$ 0.62	23%

	Nine Months Ended September 30				
	2008		2007		Per BOE
(000s except per boe amounts)	**Total**	**Per BOE**	Total	Per BOE	Change
Operating expense					
Power and fuel	**$ 59,756**	**$ 3.88**	$ 49,349	$ 2.96	31%
Well Servicing	**38,875**	**2.53**	47,639	2.87	(12%)
Repairs and maintenance	**37,235**	**2.42**	38,190	2.30	5%
Lease rentals and property taxes	**21,161**	**1.37**	15,846	0.96	43%
Processing and other fees	**8,226**	**0.53**	11,785	0.71	(25%)
Labour – internal	**18,405**	**1.20**	17,615	1.06	13%
Labour – contract	**12,487**	**0.81**	11,656	0.70	16%
Chemicals	**12,947**	**0.84**	11,533	0.69	22%
Trucking	**8,371**	**0.54**	8,906	0.53	2%
Other	**1,266**	**0.09**	12,299	0.72	(88%)
Total operating expense	**$ 218,729**	**$ 14.21**	$ 224,818	$ 13.50	5%
Transportation and marketing expense	**$ 10,232**	**$ 0.66**	$ 9,599	$ 0.58	14%

Third Quarter 2008 operating costs totaled $73.3 million, a decrease of $6.9 million from operating costs incurred in the Third Quarter of 2007. On a per barrel basis, operating costs have remained relatively constant, averaging $14.51 in the Third Quarter of 2008 compared to $14.54 in the prior year. The largest components of operating expense are power and fuel costs, well servicing and repairs and maintenance costs. Well servicing and repairs and maintenance costs continue to reflect the high demand for oilfield services, although with reduced activity compared to the same period in the prior year, these costs have remained relatively stable. On a year-to-date basis, operating costs totaled $218.7 million ($14.21/boe) for the first nine months of 2008, compared to $224.8 million ($13.50/boe) for the first nine months of 2007. This 5% per boe increase is attributed to reduced production volumes.

Power and fuel costs, comprised primarily of electric power costs, represented approximately 25% of our total operating costs during the Third Quarter of 2008. The Alberta electric power price of $80.36/MWh in the Third Quarter of 2008 was 13% lower than the average Third Quarter 2007 price of $92.00/MWh and this reduction is reflected in our 4% per boe reduction in power and fuel costs compared to the same period of the prior year, the total dollar savings offset by lower production volumes. On a year to date basis, the average Alberta electric power price for the first nine months of 2008 was $88.21/MWh as compared to $68.53/MWh during the first nine months of 2007, a 29% increase. To manage our exposure to electric power price fluctuations we have electric power price risk management contracts in place which resulted in a gain of $1.8 million and $7.0 million for the three and nine months ended September 30, 2008, respectively, compared to gains of $2.8 million and $2.7 million in the same periods of the prior year. The following table details the electric power costs per boe before and after the impact of our price risk management program.

	Three Months Ended September 30			Nine Months Ended September 30		
(per boe)	**2008**	2007	Change	**2008**	2007	Change
Electric power and fuel costs	**$ 3.69**	$ 3.55	4%	**$ 3.88**	$ 2.96	31%
Realized gains on electricity risk management contracts	**(0.36)**	(0.51)	(29%)	**(0.45)**	(0.16)	181%
Net electric power costs	**$ 3.33**	$ 3.04	10%	**$ 3.43**	$ 2.80	23%
Alberta Power Pool electricity price (per MWh)	**$ 80.36**	$ 92.00	(13%)	**$ 88.21**	$ 68.53	29%

Approximately 52% of our estimated Alberta electricity usage is protected by fixed price purchase contracts at an average price of $56.69/MWh through December 2008. These contracts moderate the impact of future price swings in electric power as will capital projects undertaken that contribute to improving our efficient use of electric power.

Third Quarter 2008 transportation and marketing expense was $3.9 million or $0.76 per boe, an increase of 23% per boe from $3.4 million or $0.62 per boe in the Third Quarter of 2007. On a year-to-date basis, transportation and marketing expense has increased 14% per boe as compared to the first nine months of the prior year, from $9.6 million or $0.58/boe in 2007 to $10.2 million or $0.66/boe in 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 fluctuate in relation with our natural gas production volumes while the cost per boe typically remains relatively constant. The increased transportation and marketing expense in the Third Quarter of 2008 is primarily due to increased clean oil trucking costs associated with the two acquisitions completed in the quarter.

Operating Netback

	Three Months Ended September 30		Nine Months Ended September 30	
(per boe)	**2008**	2007	**2008**	2007
Revenues	**$ 90.15**	$ 54.15	**$ 84.75**	$ 52.64
Royalties	**(14.50)**	(10.30)	**(13.80)**	(9.61)
Operating expense	**(14.51)**	(14.54)	**(14.21)**	(13.50)
Transportation and marketing expense	**(0.76)**	(0.62)	**(0.66)**	(0.58)
Operating netback(1)	**$ 60.38**	$ 28.69	**$ 56.08**	$ 28.95

(1) These are non-GAAP measures; 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 Third Quarter of 2008, our operating netback increased by $31.69/boe or 110% over the Third Quarter of 2007. The increase in our operating netback is primarily attributed to a $36.00/boe increase in realized commodity prices, reflecting the increase in Edmonton Par, Bow River and AECO pricing over the prior year, offset by an increase in royalties of $4.20/boe resulting from higher realized prices. For the nine months ended September 30, 2008, Harvest's operating netback was $56.08/boe, an increase of $27.13/boe or 94% compared to the same period in the prior year, attributed to significantly increased commodity prices offset by increased royalties and operating expenses.

General and Administrative ("G&A") Expense

(000s except per boe)	Three Months Ended September 30 2008	2007	Change	Nine Months Ended September 30 2008	2007	Change
Cash G&A	**$ 8,557**	$ 8,330	3%	**$ 25,344**	$ 24,048	5%
Unit based compensation expense (recovery)	**(6,410)**	(4,171)	54%	**1,422**	6,276	(77%)
Total G&A	**$ 2,148**	$ 4,159	(48%)	**$ 26,766**	$ 30,324	(12%)
Cash G&A per boe ($/boe)	**$ 1.69**	$ 1.51	12%	**$ 1.65**	$ 1.44	15%

For the three months ended September 30, 2008, Cash G&A costs increased by $0.2 million (or 3%) compared to the same period in 2007, reflecting consistent employee costs in a continued tight market for technically qualified staff in the western Canadian petroleum and natural gas industry. Generally, approximately 75% of our Cash G&A expenses are related to salaries and other employee related costs. For the nine months ended September 30, 2008, Harvest's Cash G&A was $25.3 million, an increase of 5% over the first nine months of the prior year due primarily to increased employee and consulting costs during the First Quarter of 2008.

Our unit based compensation plans provide the employee with the option of settling outstanding awards with cash. As a result, unit based compensation expense is determined using the intrinsic method, being the difference between the Trust Unit trading price and the strike price of the unit awards adjusted for the proportion that is vested. The market price of our Trust Units was $24.75 at June 30, 2008 and on September 30, 2008, the price was $17.92. This decrease in unit trading price resulted in the Third Quarter of 2008 unit based compensation expense reflecting a recovery of $6.4 million. Similarly, total unit based compensation expense decreased $2.2 million in the Third Quarter of 2008 compared to the same period in 2007 as the market price of Harvest Trust Units decreased by $6.83 per unit in the Third Quarter of 2008 which was greater than the $6.18 per unit decrease in the Third Quarter of 2007. For the year-to-date, total unit-based compensation expense of $1.4 million has been recorded, a 77% reduction compared to the same period in the prior year due to a reduced market price of Harvest Trust Units.

Depletion, Depreciation, Amortization and Accretion Expense

(000s except per boe)	Three Months Ended September 30 2008	2007	Change	Nine Months Ended September 30 2008	2007	Change
Depletion, depreciation and amortization	**$ 99,607**	$ 104,643	(5%)	**$ 305,231**	$ 313,573	(3%)
Depletion of capitalized asset retirement costs	**3,295**	3,926	(16%)	**10,273**	11,926	(14%)
Accretion on asset retirement obligation	**4,698**	4,546	3%	**13,892**	13,466	3%
Total depletion, depreciation, amortization and accretion	**$ 107,600**	$ 113,115	(5%)	**$ 329,396**	$ 338,965	(3%)
Per boe	**$ 21.29**	$ 20.51	4%	**$ 21.40**	$ 20.36	5%

Our overall depletion, depreciation, amortization and accretion ("DDA&A") expense for the three and nine months ended September 30, 2008 was $5.5 million and $9.6 million lower, respectively, compared to the same periods in the prior year. The decrease is attributed to lower production volumes partially offset by slightly higher finding and development costs that have increased our depletion rate compared to the same periods of the prior year.

Capital Expenditures

(000s)	Three Months Ended September 30 2008	2007	Nine Months Ended September 30 2008	2007
Land and undeveloped lease rentals	**$ 1,183**	$ 645	**$ 3,331**	$ 1,066
Geological and geophysical	**1,523**	1,340	**5,470**	7,064
Drilling and completion	**45,349**	38,619	**118,635**	133,608
Well equipment, pipelines and facilities	**18,317**	30,031	**52,984**	119,607
Capitalized G&A expenses	**2,672**	2,440	**7,805**	6,891
Furniture, leaseholds and office equipment	**54**	248	**112**	1,795
Development capital expenditures excluding acquisitions and non-cash items	**69,098**	73,323	**188,337**	270,031
Non-cash capital additions (recoveries)	**(1,294)**	(1,042)	**61**	(1,053)
Total development capital expenditures excluding acquisitions	**$ 67,804**	$ 72,281	**$ 188,398**	$ 268,978

Drilling activity in the Third Quarter was primarily focused on low risk oil development opportunities in some of our more active areas. At southeast Saskatchewan, Harvest drilled 18 gross (12.0) net wells as we continued to pursue light oil in the Tilston and Souris Valley formations using horizontal wells. At Lloydminster and Hayter, we drilled a total of 8 gross (7.0 net) infill horizontal wells to access incremental heavy oil from both the Lloydminster and Dina formations. In southeast Alberta we drilled 18 gross (4.6 net wells) with the majority of the net wells exploiting gas and oil opportunities in Glauconitic channel sands that traverse the area. At Markerville we drilled 11 gross (5.0 net) gas wells primarily for Edmonton sands allowing us to continue to optimize production into our operated gathering system in the area.

The following summarizes Harvest's participation in gross and net wells drilled during the three months ended September 30, 2008:

	Total Wells		Successful Wells		Abandoned Wells	
Area	Gross[1]	Net	Gross	Net	Gross	Net
Southeast Saskatchewan	18.0	12.0	18.0	12.0	-	-
Southeast Alberta	18.0	4.6	18.0	4.6	-	-
Red Earth	-	-	-	-	-	-
Suffield	-	-	-	-	-	-
Lloydminster/Hayter	8.0	7.0	8.0	7.0	-	-
Rimbey	4.0	2.5	4.0	2.5	-	-
Markerville	11.0	5.0	11.0	5.0	-	-
Other Areas	8.0	3.6	8.0	3.6	-	-
Total	67.0	34.7	67.0	34.7	-	-

(1) Excludes 4 additional wells that we have an overriding royalty interest in.

The following summarizes Harvest's participation in gross and net wells drilled during the nine months ended September 30, 2008:

	Total Wells		Successful Wells		Abandoned Wells	
Area	Gross[1]	Net	Gross	Net	Gross	Net
Southeast Saskatchewan	38.0	30.0	38.0	30.0	-	-
Southeast Alberta	26.0	9.9	26.0	9.9	-	-
Red Earth	12.0	11.3	12.0	11.3	-	-
Suffield	8.0	8.0	8.0	8.0	-	-
Lloydminster/Hayter	17.0	16.0	17.0	16.0	-	-
Rimbey	17.0	5.4	17.0	5.4	-	-
Markerville	34.0	14.4	34.0	14.4	-	-
Other Areas	13.0	7.1	13.0	7.1	-	-
Total	165.0	102.1	165.0	102.1	-	-

(1) Excludes 14 additional wells that we have an overriding royalty interest in.

Acquisitions and Divestitures

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

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

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

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 $5.8 million during the Third Quarter of 2008 as a result of accretion expense of $4.7 million, new liabilities recorded of $4.1 million offset by $3.0 million of actual asset retirement expenditures incurred.

DOWNSTREAM OPERATIONS

Third Quarter Highlights

- Cash from downstream operations totaled $47.2 million, a substantial improvement from the breakeven performance of the prior quarter and the $23.4 million cash flow deficiency of the Third Quarter in 2007.
- Refining margin of US$10.47 per barrel reflects a US$7.39 increase over the Third Quarter of the prior year and a US$4.81 increase relative to the Second Quarter of 2008 primarily attributed to higher discounts for our medium sour crude oil feedstock.
- Our cost of feedstock was US$11.40 per barrel lower than the WTI benchmark price as compared to a US$2.08 discount in the Third Quarter of the prior year and a US$1.52 discount in the Second Quarter of 2008.
- Refinery operations maintained a reduced level of throughput in July and August in an effort to improve refining margins by minimizing production of high sulphur fuel oil (HSFO) which comprised 26% of our refined product yield as compared to over 29% in the prior year. September's production averaged 103,650 bbl/d.
- Operating costs of $2.02 per barrel of throughput as compared to $2.12 in the Third Quarter of the prior year and $2.21 in the Second Quarter of 2008 reflecting a relative reduction in expenditures of approximately $2 million.
- Our cost of purchased energy of $3.72 per barrel of throughput is trending lower as compared to $4.23 and $3.27 in the First and Second Quarters of this year, respectively and is significantly higher than $2.34 in the Third Quarter of the prior year reflecting a significantly higher commodity price environment.

Summary of Financial and Operational Results

(in $000's except where noted below)	Three Months Ended September 30 **2008**	2007	Nine Months Ended September 30 **2008**	2007
Revenues	**1,214,898**	789,612	**3,504,443**	2,474,044
Purchased feedstock for processing and products purchased for resale	**1,099,963**	747,010	**3,220,513**	2,087,948
Gross Margin[(1)]	**114,935**	42,602	**283,930**	386,096
Costs and expenses				
Operating expense	**23,357**	24,775	**74,868**	76,720
Purchased energy expense	**33,958**	22,340	**106,985**	64,677
Turnaround and catalyst expense	**1,011**	6,622	**1,011**	6,622
Marketing expense	**8,560**	10,673	**26,558**	27,075
General and administrative expense	**345**	522	**1,514**	1,224
Depreciation and amortization expense	**17,195**	17,280	**50,438**	54,854
Earnings (loss) from operations[(1)]	**30,509**	(39,610)	**22,556**	154,924
Cash capital expenditures	**17,199**	12,468	**31,845**	27,222
Feedstock volume (bbl/day)[(2)]	**99,127**	103,983	**103,832**	111,052
Yield (000's barrels)				
Gasoline and related products	**2,757**	3,073	**8,801**	9,762
Ultra low sulphur diesel and jet fuel	**3,985**	3,596	**12,001**	11,829
High sulphur fuel oil	**2,348**	2,785	**7,448**	8,480
Total	**9,090**	9,454	**28,250**	30,071
Average Refining Margin (US$/bbl)[(3)]	**10.47**	3.08	**8.38**	10.57

[(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 North American refining industry has numerous pricing indicators against which to compare refinery gross margin performance. Typically, these gross margin indicators include prices for refined products such as Reformulated Blendstock for Oxygenate Blending gasoline ("RBOB gasoline") and heating oil. The New York Mercantile Exchange ("NYMEX") "2-1-1 Crack Spread" is such an indicator and is calculated assuming that the processing of two barrels of light sweet crude oil (defined as a WTI quality) yields one barrel of RBOB gasoline and one barrel of heating oil both of which are delivered to the New York market where product prices are set in relation to NYMEX RBOB gasoline and NYMEX heating oil prices. The following average prices, gross margin indicators and currency exchange rates are provided as reference points with which to index our refinery's performance:

	Three Months Ended September 30			Nine Months Ended September 30		
	2008	**2007**	**Change**	**2008**	**2007**	**Change**
WTI crude oil (US$/bbl)	**117.98**	75.38	57%	**113.29**	66.19	71%
Brent crude oil (US$/bbl)	**116.87**	74.87	56%	**111.07**	67.10	66%
Basrah Official Sales Price Discount (US$/bbl)	**(6.70)**	(5.03)	33%	**(7.52)**	(5.89)	28%
RBOB gasoline (US$/bbl/gallon)	**123.91/2.95**	87.02/2.07	42%	**120.57/2.87**	83.80/2.00	44%
Heating Oil (US$/bbl/gallon)	**138.66/3.30**	87.86/2.09	58%	**134.13/3.19**	79.30/1.89	69%
High Sulphur Fuel Oil (US$/bbl)	**96.03**	57.19	68%	**83.75**	49.14	70%
2-1-1 Crack Spread (US$/bbl)	**13.31**	12.06	10%	**14.06**	15.36	(9%)
Canadian / US dollar exchange rate	**0.960**	0.957	0%	**0.982**	0.907	8%

During the Third Quarter of 2008, the 2-1-1 Crack Spread increased US$1.25/bbl as compared to the same period in the prior year reflecting an US$8.20/bbl increase in the Heating Oil Crack Spread to US$20.68/bbl offset by a decrease of US$5.71 in the RBOB Crack Spread to US$5.93/bbl. For the nine month period ended September 30, 2008, the 2-1-1 Crack Spread decreased by US$1.30/bbl as compared to the prior year due to a US$10.33/bbl decrease in the RBOB Crack Spread to US$7.28/bbl offset by a US$7.73/bbl increase in the Heating Oil Crack Spread to US$20.84/bbl.

Harvest's refining margin differs from that represented by the 2-1-1 Crack Spread indicator due to the refined product mix produced by the refinery as well as the type of crude oil feedstock processed. Our refinery produces approximately 25% - 30% high sulphur fuel oil ("HSFO"), a product not represented in the NYMEX 2-1-1 Crack Spread. HSFO typically sells at a discount to WTI and has a negative contribution to our refining margin. Our refinery also processes a medium gravity sour crude oil, purchased at a discount to WTI, rather than a WTI quality of light sweet crude oil represented in the 2-1-1 Crack Spread. To optimize the throughput of our Isomax hydrocracker unit, we typically purchase approximately 5,000 – 10,000 bbl/d of vacuum gas oil ("VGO") which may sell at a price that is either a premium or discount to WTI.

Downstream Gross Margin

The following summarizes Harvest downstream gross margin contributions for each of the three and nine months ended September 30, 2008 and 2007 segregated between refining activities and marketing and other related businesses.

	Three Months Ended September 30					
	2008			2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Sales revenue[1]	**1,187,890**	**220,402**	**1,214,898**	764,075	158,292	789,612
Cost of feedstock for processing and products for resale[1]	**1,088,455**	**204,902**	**1,099,963**	733,302	146,463	747,010
Gross margin[2]	**99,435**	**15,500**	**114,935**	30,773	11,829	42,602
Average Refining Margin (US$/bbl)	**10.47**			3.08		

	Nine Months Ended September 30					
	2008			2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Sales revenue[1]	**3,425,471**	**544,698**	**3,504,443**	2,404,522	364,986	2,474,044
Cost of feedstock for processing and products for resale[1]	**3,182,804**	**503,435**	**3,220,513**	2,051,188	332,224	2,087,948
Gross margin[2]	**242,667**	**41,263**	**283,930**	353,334	32,762	386,096
Average Refining Margin (US$/bbl)	**8.38**			10.57		

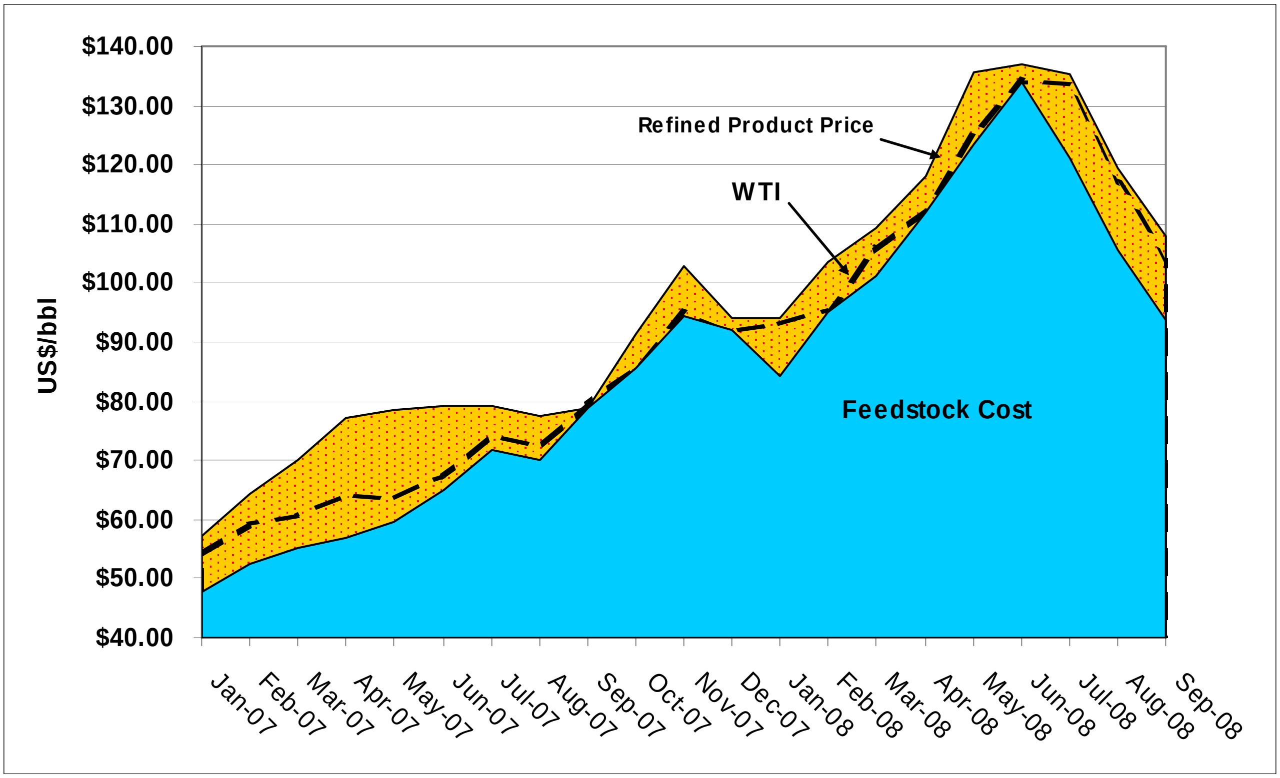
(1) Downstream sales revenue and cost of products for processing and resale are net of intra-segment sales of $193.4 million and $465.7 million for the three and nine months ended September 30, 2008 respectively ($132.8 million and $295.5 million – three and nine months ended September 30, 2007) reflecting the refined products produced by the refinery and sold by Marketing Division.

(2) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

Harvest's refining margin comprises sales of refined petroleum products that realize a premium price relative to WTI while it purchases crude oil and VGO as feedstock which is typically purchased at a discount relative to WTI. During the Third Quarter of 2008, our refining margin totaled $99.4 million, or US$10.47/bbl which is a 223% increase compared to the margin of $30.8 million or US$3.08/bbl realized during the Third Quarter of 2007. This increase is attributed to a significant improvement in the discount on feedstock costs relative to WTI in the Third Quarter of 2008 as compared to the same period in 2007, marginally offset by a reduction in the refined product sales prices relative to WTI between the Third Quarters of 2008 and 2007.

For the nine months ended September 30, 2008, Harvest's refining margin totaled $242.7 million, a reduction of $110.7 million compared to the first nine months of the prior year, reflecting an average refining margin of US$8.38/bbl in 2008 as compared to US$10.57/bbl in 2007. The US$2.19/bbl year-over-year decrease in our average refining margin is due to lower gasoline and HSFO crack spreads, only partially offset by improved crack spreads on distillate products and an improved discount on our cost of feedstock relative to WTI.

The following summarizes our refining margin per barrel relative to our cost of feedstock and the WTI benchmark from the period January 2007 to September 2008:



Relative to the average Third Quarter 2008 2-1-1 Crack Spread of US$13.31, our average refining margin of US$10.47/bbl is US$2.84/bbl lower as compared to being US$8.98/bbl lower than the 2-1-1 Crack Spread in the Third Quarter of the prior year. The relative improvement in our refining margin is primarily attributed to the higher discount on our purchases of medium gravity sour crude oil feedstock relative to WTI. In the Third Quarter of 2008, the average cost of our crude oil feedstock was US$105.01, a discount of US$12.97/bbl relative to WTI as compared to an average cost of US$71.85/bbl and a discount of US$3.53/bbl in the prior year.

On a year-to-date basis, our average refining margin of US$8.38/bbl was US$5.68/bbl lower than the average 2-1-1 Crack Spread of US$14.06 for the first nine months of 2008. This compares to an average refining margin of US$10.57/bbl which was US$4.79/bbl lower than the 2-1-1 Crack Spread for the nine months ended September 30, 2007. The US$0.89/bbl increase in differential from the 2-1-1 Crack Spread is primarily attributed to increased discounts for HSFO coupled with lower crack spreads on RBOB gasoline, partially offset by higher crack spreads on distillates and increased discounts on our cost of feedstock.

Harvest's marketing and related businesses is comprised of the retail and wholesale distribution of gasoline, diesel, jet and other transportation fuels as well as home heating fuels and related appliances and the revenues from our marine services including tugboat revenues. During the three and nine months ended September 30, 2008, the gross margin contributed by our marketing division increased by 31% and 26%, respectively, as compared to the prior year primarily due to a significant increase in the price of sulphur, which is sold through a profit sharing agreement with a third party processor. The profit sharing contribution from our sulphur sales is $2.6 million for the three months ended September 30, 2008 (three months ended September 30, 2007 - $0.2 million) and $8.3 million for the nine months ended September 30, 2008 (nine months ended September 30, 2007 - $0.3 million).

Refined Product Sales Revenue

All of our gasoline and distillate products are sold to Vitol pursuant to the Supply and Offtake Agreement with the exception of products sold in Newfoundland through our marketing division and effective January 20, 2008, our HSFO which is now sold to a wholly-owned affiliate of one of the world's largest integrated oil and natural gas producers. Prior to January 20, 2008, our HSFO had also been sold to Vitol. The Supply and Offtake Agreement has pricing terms that reflect market prices based on an average delay of ten days which results in our sales to Vitol and our cost of refinery feedstock purchased from Vitol being priced on a slightly different time period than the prices at the time of delivery. With the exception of the sales to Vitol, our refined products are sold at prices that reflect market prices at the time that the product is delivered to the purchaser. For more information on the Supply and Offtake Agreement with Vitol, see the description in our Annual Information Form for the year ended December 31, 2007 as filed on SEDAR at www.sedar.com.

A comparison of our refinery yield, product pricing and revenue for each of the three and nine months ended September 30, 2008 and 2007 is presented below.

	Three Months Ended September 30					
	2008			2007		
	Refinery Revenues	**Volume**	**Sales Price(1)**	Refinery Revenues	Volume	Sales Price(1)
	(000's of Cdn $)	(000s of bbls)	(US$ per bbl/ US$ per US gal)	(000's of Cdn $)	(000s of bbls)	(US$ per bbl/ US$ per US gal)
Gasoline products	**408,292**	**3,329**	**117.74/2.80**	249,628	2,800	85.32/2.03
Distillates	**545,610**	**3,841**	**136.37/3.25**	344,521	3,719	88.65/2.11
High sulphur fuel oil	**233,988**	**2,267**	**99.09**	169,926	2,791	58.27
	1,187,890	**9,437**	**120.84**	764,075	9,310	78.54
Inventory adjustment		**(347)**			144	
Total production		**9,090**			9,454	
Yield (as a % of Feedstock) (2)		**100%**			99%	

	Nine Months Ended September 30					
	2008			2007		
	Refinery Revenues	**Volume**	**Sales Price(1)**	Refinery Revenues	Volume	Sales Price(1)
	(000's of Cdn $)	(000s of bbls)	(US$ per bbl/ US$ per US gal)	(000's of Cdn $)	(000s of bbls)	(US$ per bbl/ US$ per US gal)
Gasoline products	**1,130,160**	**9,567**	**116.00/2.76**	861,246	9,343	83.61/1.99
Distillates	**1,664,774**	**11,901**	**137.37/3.27**	1,072,177	11,785	82.52/1.96
High sulphur fuel oil	**630,537**	**7,235**	**85.58**	471,099	8,484	50.36
	3,425,471	**28,703**	**117.19**	2,404,522	29,612	73.65
Inventory adjustment		**(453)**			459	
Total production		**28,250**			30,071	
Yield (as a % of Feedstock) (2)		**99%**			99%	

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

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

Our refinery sales revenue is dependent on the sales value of the refined products produced as well as the yield of refined products produced from the various crude oil feedstocks. We analyze our sales revenue from refined product sales relative to the premium (or discount) compared to industry benchmark prices for specific refined products as well as relative to the WTI benchmark price. Although our yield can be altered slightly by adjusting refinery operations to react to market conditions and seasonal demand, product yields are primarily impacted by the type of crude oil feedstock processed and refinery performance. For the three months ended September 30, 2008, our refinery yield was comprised of 30% gasoline products, 44% distillates and 26% HSFO as compared to 33%, 38% and 29%, respectively, in the prior year. For the nine months ended September 30, 2008, our refinery yield was comprised of 31% gasoline products, 43% distillates and 26% HSFO compared to 33%, 39% and 28% for the same products, respectively during 2007. The shift in product yield in 2008 relative to 2007 from HSFO and gasoline to higher valued distillates is attributed to running less crude oil and more VGO, running a different crude oil slate, and the reduction of crude oil throughput volumes in July and August of 2008 to the level sufficient to eliminate the production of vacuum tower bottoms ("VTB's") in excess of our visbreaker unit capacity, thereby eliminating the need to downgrade middle distillate valued streams to blend the excess VTB's into HSFO.

The aggregate average sales price for our refined products was US$120.84/bbl during the Third Quarter of 2008, representing premium to WTI of US$2.86/bbl as compared to an average selling price of US$78.54/bbl realized in the Third Quarter of the prior year with a premium to WTI of US$3.16/bbl. The reduction of US$0.30/bbl in our sales price relative to WTI aggregates to a $2.9 million reduction in sales revenue and gross margin.

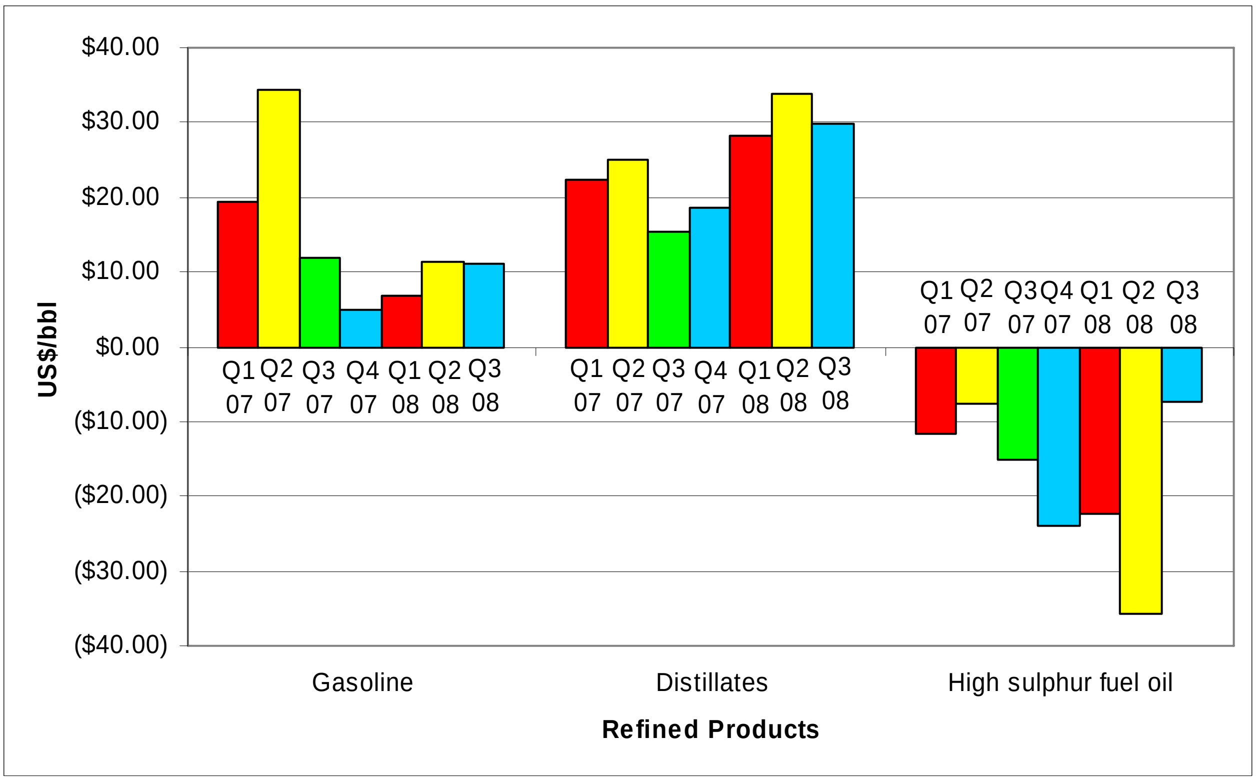
During the Third Quarter of 2008, the US$117.74/bbl average sales price for our gasoline products reflects a US$0.24/bbl discount to WTI, as compared to the US$9.94/bbl premium over WTI realized in 2007. This discount relative to WTI in the Third Quarter of 2008 reflects the weaker RBOB gasoline Crack Spreads evident in the Fourth Quarter of 2008.

For distillates, our average sales price was US$136.37/bbl during the Third Quarter of 2008, a US$18.39/bbl premium over WTI, as compared to a US$13.27/bbl premium realized in the Third Quarter of 2007. Included in our Third Quarter 2008 distillate revenue are approximately 1.6 million barrels of distillate product that were sold in Europe for which we received $2.4 million of incremental revenue (US$1.47 per barrel) pursuant to our profit sharing arrangement with Vitol.

The average sales price of our HSFO of US$99.09/bbl reflects a US$18.89/bbl discount to WTI as compared to a US$17.11/bbl discount in the Third Quarter of 2007, representing a $4.0 million reduction in sales revenue and gross margin as compared to the prior year. The average sales price of our HSFO in the Third Quarter of 2008 represents a US$18.45 improvement over the US$37.34 discount realized in the Second Quarter of 2008. The US$5.12 improvement in our distillate pricing relative to WTI and the shift in product yield from gasoline and HSFO to distillates was insufficient to fully offset the impact of the US$10.18 and US$1.78 price reductions relative to WTI for our gasoline products and HSFO, respectively.

During the nine months ended September 30, 2008, our average aggregate selling price for refined products was US$117.19/bbl, representing a premium to the average WTI price of US$3.90/bbl compared to an average selling price of US$73.65/bbl and a premium to WTI of US$7.46/bbl during 2007, a reduction of US$3.56/bbl. This reduction is attributed to an 84% reduction in the gasoline premium relative to WTI and a 75% increase in the discount on HSFO relative to WTI, partially offset by improved premiums relative to WTI on distillate products of 47% and the shift in product yield from gasoline and HSFO to distillates.

The following chart summarizes Harvest's refining margin by product per barrel over the past seven quarters:



Refinery Feedstock

We purchase our refinery feedstock from Vitol pursuant to the terms of the Supply and Offtake Agreement whereby the price of feedstock floats with WTI for the period from initial pricing through to the date it is charged to the refinery subject to an average ten day delay similar to the product sales pricing formulas. This method of pricing results in our costs being based on a slightly different time period than the monthly average WTI benchmark price. The WTI benchmark price averaged US$133.48 for the month of July 2008, US$116.69 for August 2008 and US$103.76 for September 2008 as compared to the average for the three months ended September 2008 of US$117.98. This volatility in WTI results in it being difficult to compare the economics of individual crude costs on a quarterly basis when our consumption of crude types varies from month to month and the aggregation of feedstock costs, including their discount relative to WTI, is priced based on benchmark pricing ten days after consumption.

A comparison of crude oil and VGO feedstock processed for the three and nine months ended September 30, 2008 and 2007 is presented below.

	Three Months Ended September 30					
	2008			2007		
	Cost of Feedstock	**Volume**	**Cost per Barrel[(1)]**	Cost of Feedstock	Volume	Cost per Barrel[(1)]
	(000's of Cdn $)	(000s of bbls)	(US$/bbl)	(000's of Cdn $)	(000s of bbls)	(US$/bbl)
Iraqi	**390,848**	**3,573**	**105.01**	478,504	6,384	71.73
Russian	**277,250**	**2,489**	**106.93**	85,304	1,125	72.57
Venezuelan	**223,918**	**2,093**	**102.70**	90,792	1,210	71.81
Crude Oil Feedstock	**892,016**	**8,155**	**105.01**	654,600	8,719	71.85
Vacuum Gas Oil	**120,505**	**965**	**119.88**	78,060	847	88.20
	1,012,521	**9,120**	**106.58**	732,660	9,566	73.30
Other costs	**75,934**			642		
	1,088,455			733,302		

	Nine Months Ended September 30					
	2008			2007		
	Cost of Feedstock	**Volume**	**Cost per Barrel[(1)]**	Cost of Feedstock	Volume	Cost per Barrel[(1)]
	(000's of Cdn $)	(000s of bbls)	(US$/bbl)	(000's of Cdn $)	(000s of bbls)	(US$/bbl)
Iraqi	**1,614,974**	**15,101**	**105.02**	1,337,812	20,179	60.13
Russian	**557,234**	**5,194**	**105.35**	237,311	3,371	63.85
Venezuelan	**580,289**	**5,352**	**106.47**	263,293	4,089	58.40
Crude Oil Feedstock	**2,752,497**	**25,647**	**105.39**	1,838,416	27,639	60.33
Vacuum Gas Oil	**346,470**	**2,802**	**121.43**	212,407	2,678	71.94
	3,098,967	**28,449**	**106.97**	2,050,823	30,317	61.35
Other costs	**83,837**			365		
	3,182,804			2,051,188		

(1) Cost of feedstock includes all costs of transporting the crude oil to refinery in Newfoundland

During the Third Quarter of 2008, our feedstock was comprised of 88,641 bbl/d of medium sour crude oil and 10,486 bbl/d of VGO as compared to 94,774 bbl/d of crude oil and 9,209 bbl/d of VGO in the prior year. While the refinery experienced limited unplanned downtime during the Third Quarter of 2008, our daily volume of crude oil throughput decreased by 6,133 bbl/d due to a decision to improve overall gross margin by reducing crude oil feedstock volumes to the level sufficient to eliminate the production of vacuum tower bottoms ("VTB's") in excess of our visbreaker unit capacity, thereby eliminating the need to downgrade middle distillate valued streams to blend the excess VTB's into HSFO. To offset the reduced crude oil throughput, VGO purchases were increased to maintain ISOMAX rates at the highest possible levels and maximize the gross margin contribution from this process unit.

The cost of our crude oil feedstock averaged US$105.01/bbl during the Third Quarter of 2008 representing a US$12.97/bbl discount from WTI as compared to a cost of US$71.85/bbl and a discount of US$3.53/bbl, respectively, in the prior year. While the increased discount to WTI of US$9.44/bbl aggregates to an $80.2 million decrease in crude oil feedstock costs, the year-over-year US$42.60 increase in the WTI price added $361.9 million to our crude oil feedstock cost during the Third Quarter of 2008. In aggregate, the US$105.01/bbl average cost of feedstock during the Third Quarter of 2008 represents a 46% increase over the average cost in the prior year, which impacts our working capital and increases our "Time Value of Money" charges paid to Vitol as part of the Supply and Offtake agreement. The cost of feedstock reflects numerous factors beyond changes in WTI such as the crude oil slate processed during the period, the Official Selling Price ("OSP") as set by the Oil Marketing Company of the Republic of Iraq, the costs of transporting the crude feedstock to our refinery and the ten day delay in pricing as a result of the Supply and Offtake pricing formula.

The average cost of purchased VGO during the Third Quarter of 2008 was US$119.88/bbl representing a premium of US$1.90/bbl relative to the WTI benchmark price as compared to US$88.20/bbl and a US$12.82/bbl premium, respectively, in the prior year. The higher premium in 2007 is attributed to supply and demand disruptions in that year in the very tightly balanced VGO market. We processed 1.0 million barrels of VGO during the Third Quarter of 2008, as such the US$10.92/bbl lower premium aggregates to an $11.0 million decrease in feedstock costs and similarly, an $11.0 million increase in gross margin compared to the Third Quarter of 2007.

During the first nine months of 2008, the total cost of feedstock was US$106.97/bbl, an increase of US$45.62/bbl over the first nine months of 2007 during which the total cost averaged US$61.35/bbl. This increase is primarily attributed to the 71% increase in WTI during the first nine months of 2008 relative to the first nine months of 2007, coupled with a US$2.39/bbl increase in the premium paid for VGO relative to WTI, partially offset by a US$2.04/bbl increase in the average discount realized to WTI on crude oil purchases.

Operating Expenses

The following summarizes the operating costs from the refinery and marketing division for the three and nine months ended September 30, 2008 and 2007:

	Three Months Ended September 30					
	2008			2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Operating expense	**18,458**	**4,899**	**23,357**	20,262	4,513	24,775
Turnaround and catalyst	**1,011**	**-**	**1,011**	6,622	-	6,622
Purchased energy	**33,958**	**-**	**33,958**	22,340	-	22,340
	53,427	**4,899**	**58,326**	49,224	4,513	53,737

	Nine Months Ended September 30					
	2008			2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Operating expense	**60,022**	**14,846**	**74,868**	63,415	13,305	76,720
Turnaround and catalyst	**1,011**	**-**	**1,011**	6,622	-	6,622
Purchased energy	**106,985**	**-**	**106,985**	64,677	-	64,677
	168,018	**14,846**	**182,864**	134,714	13,305	148,019

The largest component of refining operating expense is wages, salaries and benefits which totaled $12.5 million during the Third Quarter of 2008 (2007 - $13.1 million) while the other significant components were maintenance and repairs costs of $2.0 million (2007 - $2.5 million), insurance of $1.5 million (2007 - $1.5 million) and professional services of $1.6 million (2007 - $1.5 million). Refining operating expenses were $2.02/bbl during the Third Quarter of 2008 as compared to $2.12/bbl in the Third Quarter of 2007 reflecting a relative reduction in expenditures of $1.8 million somewhat offset by reduced throughput.

On a year-to-date basis, downstream operating costs were $74.9 million in 2008, a decrease of $1.9 million from the first nine months of 2007. Refining operating expenses were $2.11/bbl as compared to $2.09/bbl in the prior year due primarily to reduced throughput. The Marketing division's operating expenses have increased by $1.5 million primarily due to scheduled tug boat maintenance in June 2008.

Turnaround and catalyst expenditures of $0.4 million and $0.6 million respectively (2007 - $2.6 million and $4.0 million, respectively), relate to planned equipment certifications scheduled during the shutdown to implement the visbreaker unit project modifications.

Purchased energy, consisting of low sulphur fuel oil and electricity, is required to provide heat and power to refinery operations. Our purchased energy for the three and nine months ended September 30, 2008 was $3.72 and $3.76 per barrel of throughput, respectively, as compared to $2.34/bbl and $2.13/bbl for the three and nine month periods ended September 30, 2007. In the Third Quarter of 2008, we purchased approximately 355,000 barrels of fuel oil at an average price of US$85.03/bbl as compared to approximately 283,000 barrels purchased in the Third Quarter of 2007 at an average price of US$67.23/bbl. The $11.6 million increase in the cost of purchased fuel oil is due to a $6.5 million favourable price variance and a $5.1 million favourable volume variance. Our electricity costs remained substantially unchanged during the Third Quarter of 2008 at $2.5 million as compared to $2.4 million in the prior year.

Marketing Expense

During the three and nine months ended September 30, 2008, marketing expense was comprised of $0.9 million and $2.5 million, respectively, of marketing fees (based on US $0.08/bbl) to acquire feedstock (three and nine months ended September 30, 2007 - $0.8 million and $2.8 million) and $7.7 million and $24.1 million, respectively, of "Time Value of Money" charges (three and nine months ended September 30, 2007 - $9.9 million and $24.3 million) 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 Third Quarter of 2008 as compared to the prior year which was somewhat offset by a larger crude oil inventory investment due to the higher WTI benchmark price during 2008. As at September 30, 2008, Harvest has commitments totaling approximately $859.9 million in respect of future crude oil feedstock purchases and related transportation from Vitol.

Capital Expenditures

Capital spending for the three and nine month periods ended September 30, 2008 totaled $17.2 million and $31.8 million respectively. The largest component of our 2008 downstream capital program relates to the enhancement of our visbreaker capacity, estimated at $28.5 million, of which approximately $10.5 million was incurred in the Third Quarter ($16.4 million year-to-date).

Depreciation and Amortization Expense

The following summarizes the depreciation and amortization expense for the three and nine months ended September 30, 2008 and 2007:

	Three Months Ended September 30					
	2008			2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Tangible assets	**15,045**	**652**	**15,697**	15,250	503	15,753
Intangible assets	**1,159**	**339**	**1,498**	1,163	364	1,527
	16,204	**991**	**17,195**	16,413	867	17,280

	Nine Months Ended September 30					
	2008			2007		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	Refining	Marketing	Total
Tangible assets	**44,225**	**1,817**	**46,042**	48,544	1,468	50,012
Intangible assets	**3,400**	**996**	**4,396**	3,688	1,154	4,842
	47,625	**2,813**	**50,438**	52,232	2,622	54,854

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, our MD&A for the year ended December 31, 2007 included a comprehensive discussion of our approach to analyzing our cash flow at risk relative to changes in crude oil prices, natural gas prices, the US/Canadian dollar exchange rate and certain refined product prices. See the "Cash Flow Risk Management" in our MD&A for the year ended December 31, 2007 filed on SEDAR at www.sedar.com. The details of our commodity price contracts outstanding at September 30, 2008 are included in the notes to our consolidated financial statements which are also filed on SEDAR at www.sedar.com.

While strong commodity prices experienced throughout 2008 have resulted in record operating cash flow from our upstream activities, this has also resulted in significant realized losses on our price risk management contracts. The table below provides a summary of the gains and losses realized on our price risk management contracts for each of the three month and nine month periods ended September 30, 2008 and 2007:

	Three Months Ended September 30			Nine Months Ended September 30		
(000s)	**2008**	2007	Change	**2008**	2007	Change
Crude oil	**$ (17,568)**	$ (12,922)	36%	**$ (41,255)**	$ (19,675)	110%
Refined product	**(78,648)**	-	n/a	**(195,738)**	-	n/a
Natural gas	**(67)**	6,275	(101%)	**(325)**	6,566	(105%)
Currency exchange rates	**(33)**	2,051	(102%)	**5,125**	1,450	253%
Electric Power	**1,818**	2,803	(35%)	**6,977**	2,743	154%
Total	**$ (94,498)**	$ (1,793)	5,170%	**$ (225,216)**	$ (8,916)	2,426%

During the first nine months of 2008, the net realized loss on price risk management contracts aggregated to $225.2 million as compared to $8.9 million in the prior year. This increase is primarily due to the increased losses related to our crude oil and refined product pricing contracts offset somewhat by increased gains on currency exchange rate and electric power contracts. During this period, WTI averaged US$113.29 in 2008 as compared to US$66.19 in 2007, while the contracted prices capped our WTI price exposure at an average of US$75.06 on approximately 29,000 bbls/d in 2008 while in 2007 our crude oil price contracts had price caps of approximately US$56.00 and included approximately 70% participation on prices above US$56.00 on approximately 28,000 bbls/d. For the balance of 2008, we have capped our WTI price exposure on 26,075 bbls/d at an average of US$80.86, while providing a floor price of US$53.85. Our exposure in 2009 is capped on 20,000 bbls/d at an average of US$85.09, with a floor price of US$61.94. As discussed in our 2007 year end MD&A, our WTI price risk management is comprised of both WTI price contracts as well as the refined product price contracts for heating oil and fuel oil, as refined product prices are essentially comprised of a WTI benchmark price plus the related crack spread, in our case, either a NYMEX heating oil or Platt's fuel oil crack spread. Relative to our average 32,637 bbls/d of daily production of crude oil and natural gas liquids, net of royalties, during the Third Quarter of 2008, our price risk management contracts left 6,562 bbls/d of net production exposed to WTI prices above US$80.86.

In respect of refined products, we also had pricing contracts in place for 12,000 bbl/d of NYMEX heating oil and 8,000 bbl/d of Platts heavy fuel oil for the Third Quarter of 2008 and the cash settlements of these contracts aggregated to $78.5 million during the quarter. In addition, we had contracts in place on 6,000 bbl/d of NYMEX heating oil crack spread, 2,000 bbl/d of Platts heavy fuel oil crack spread and 6,000 bbl/d of NYMEX RBOB gasoline crack spread which were settled with cash payments of $0.1 million during the Third Quarter of 2008. As of September 30, 2008, we had the following refined product price contracts in place:

For the period from October 2008 through December 2008

- 12,000 bbl/d of NYMEX heating oil,
- 8,000 bbl/d of Platts heavy fuel oil,
- 6,000 bbl/d of NYMEX heating oil crack spread
- 2,000 bbl/d of Platts heavy fuel oil crack spread, and
- 6,000 bbl/d of NYMEX RBOB gasoline comprised of an RBOB crack contract and a WTI price contract.

For the period from January 2009 through June 2009

- 12,000 bbl/d of NYMEX heating oil, and
- 8,000 bbl/d of Platts heavy fuel oil.

At the end of September 2008, we had a modest 776 GJ/d of natural gas price contracts in place through December 2008.

With respect to currency exchange rates, we had an exchange rate collar in place that collared an exchange rate of Cdn$1.00 to Cdn$1.055 per US$1.00 on US$10 million per month. The settlements on the exchange rate collar settled with a nominal payment by Harvest in the Third Quarter of 2008. The exchange rate collar extends through December 2008.

During the Third Quarter of 2008, the settlement of our fixed price power contracts for 35 MWh at $56.69 per MWh resulted in $1.8 million received by Harvest as the Alberta electric power prices averaged $80.36 per MWh during the period. This fixed price contract continues for 35 MWh through December 2008.

The following is a summary of net unrealized gains and losses recorded for our price risk management contracts for each of the three and nine month periods ended September 30, 2008 and 2007:

	Three Months Ended September 30			Nine Months Ended September 30		
(000s)	**2008**	2007	Change	**2008**	2007	Change
Crude oil	**$ 48,474**	$ (2,836)	(1,809%)	**$ 13,351**	$ (14,205)	(194%)
Refined product	**316,116**	(15,697)	(2,114%)	**(7,001)**	(24,348)	(71%)
Natural gas	**413**	(5,183)	(108%)	**180**	(644)	(128%)
Currency exchange rates	**(1,024)**	6,600	(116%)	**(9,160)**	17,666	(152%)
Electric Power	**(4,325)**	(4,819)	(10%)	**(3,701)**	(3,511)	5%
Total	**$ 359,654**	$ (21,935)	(1,740%)	**$ (6,331)**	$ (25,042)	(75%)

At the end of 2007, the mark-to-market deficiency on our refined product and WTI price contracts was $138.8 million and $24.9 million, respectively, while the mark-to-market value of our natural gas, currency exchange rate and electrical power price contracts aggregated to $14.0 million. As of September 30, 2008, the mark-to-market deficiency on our refined product and WTI price contracts was $157.7 million while the mark-to-market value of our natural gas, currency exchange rate and electrical power price contracts aggregated to $1.3 million. The unrealized gain on our refined product and WTI price contracts in the Third

Quarter of 2008 is due to the decrease in forward commodity prices at September 30, 2008 as compared to those at June 30, 2008, which has resulted in a partial recovery of the unrealized losses on our refined product and WTI price contracts recorded during the first six months of 2008.

In October 2008, the settlement of our price risk management contracts resulted in cash receipts of $1.5 million in respect of our refined product and WTI price contracts and $1.1 million in respect of our Alberta power price contracts, offset by cash payments of $1.3 million in respect of our currency exchange rate contract. On October 31, 2008, the WTI forward price curve was approximately US$30.00 lower than on September 30, 2008 which combined with other fluctuations in forward refined product prices has resulted in our mark-to-market deficiency at the end of October being approximately $154.0 million lower than at the end of September.

Interest Expense

	Three Months Ended September 30			Nine Months Ended September 30		
(000s)	**2008**	2007	Change	**2008**	2007	Change
Interest on short term debt						
Bank loan	**$ -**	$ -	-%	**$ -**	$ 1,275	(100%)
Convertible Debentures	**32**	606	(95%)	**233**	1,900	(88%)
Amortization of deferred finance charges – short term debt	**-**	-	-%	**-**	1,811	(100%)
	32	606	(95%)	**233**	4,986	(95%)
Interest on long-term debt						
Bank loan	**12,514**	16,373	(24%)	**40,959**	52,903	(23%)
Convertible Debentures	**19,290**	13,193	46%	**49,899**	43,587	14%
7⁷/⁸% Senior Notes	**5,584**	5,523	1%	**16,231**	17,328	(6%)
Amortization of deferred finance charges – long term debt	**675**	675	0%	**2,024**	2,022	0%
	38,063	35,764	6%	**109,113**	115,840	(6%)
Total interest expense	**$ 38,095**	$ 36,370	5%	**$ 109,346**	$ 120,826	(10%)

Interest expense, including the amortization of related financing costs, increased $1.7 million and decreased $11.5 million in the three and nine month periods ended September 30, 2008, respectively, as compared to the same periods in the prior year. The 5% increase in the Third Quarter of 2008 over the Third Quarter of 2007 is primarily attributed to the increase in interest expense incurred on convertible debentures, offset by a reduction of interest on our bank borrowings. On a year-to-date basis, our total interest expense has decreased by 10% compared to the prior year, as interest on our bank borrowings has decreased by $13.2 million due to a lower average borrowing cost, while total interest expense on convertible debentures has increased as a result of our 2008 convertible debenture offering.

At September 30, 2008, we had drawn approximately $1,199.8 million of bank borrowings as compared to $1,279.5 million at December 31, 2007 and $1,035.3 million at June 30, 2008. The year-to-date decrease in our outstanding bank borrowings is primarily attributed to applying the net proceeds from the 7.5% Convertible Debenture offering completed in the Second Quarter 2008 against our outstanding debt, offset by the acquisitions completed in the Third Quarter 2008. 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 and nine month periods ended September 30, 2008, interest charges on bank loans aggregated to $12.5 million and $41.0 million, reflecting effective interest rates of 3.92% and 4.21% respectively. Further details on our credit facilities are included under "Liquidity and Capital Resources".

The interest on our Convertible Debentures totaled $19.3 million and $50.1 million during the three and nine months ended September 30, 2008 respectively, representing a $5.5 million and $4.6 million increase over the same periods in the prior year. The increase is due to the April 25 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, 2007 filed on SEDAR at www.sedar.com. During the three and nine months ended September 30, 2008, there were $15,000 and $24.4 million of principal amount of Convertible Debentures converted to 1,083 and 1,177,957 Trust Units, respectively, including the settlement of $24.2 million principal amount of 10.5% Convertible Debentures that matured on January 31, 2008 with 1,166,593 Trust Units. Interest on the Convertible Debentures is based on the effective yield of the debt component of the Convertible Debentures, and as a result, the interest expense recorded is greater than the cash interest paid.

The interest on our 7⁷/⁸% Senior Notes totaled $5.6 million and $16.2 million for the three and nine month periods ended September 30, 2008, representing a $0.1 million increase and a $1.1 million decrease over the same periods in the prior year. The year-to-date decrease is due to the strength of the Canadian dollar during these periods as compared to the relative periods 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 7⁷/⁸% Senior Notes, the accretion on the debt component balance of the Convertible Debentures to face value at maturity, as well as the amortization of commitment fees and legal costs incurred for our credit facility, all totaling $0.7 million and $2.0 million for the three and nine month periods ended September 30, 2008 respectively.

Currency Exchange

Currency exchange gains and losses are attributed to the changes in the value of the Canadian dollar relative to the U.S. dollar on our U.S. dollar denominated 7⁷/⁸% Senior Notes as well as any other U.S. dollar cash balances. Since December 31, 2007, the Canadian dollar has modestly weakened compared to the U.S dollar, resulting in a year-to-date unrealized foreign exchange loss of $15.1 million. Of this unrealized loss, $17.8 million relates to the 7⁷/⁸% Senior Notes, offset by $3.2 million of unrealized foreign exchange gains attributed to downstream transactions. Realized foreign exchange losses of $6.1 million and $7.3 million for the three and nine months ended September 30, 2008, respectively, have resulted from the settlement of US dollar denominated transactions. In the Third Quarter of 2007 we repaid our U.S. dollar denominated LIBOR bank loans that were incurred in connection with our purchase of North Atlantic, realizing a foreign exchange gain of $43.5 million in the quarter and $47.1 million year-to-date in respect of this loan.

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 Third Quarter of 2008, the weakening of the Canadian dollar relative to the U.S. dollar resulted in a $56.6 million cumulative translation gain (nine months ended September 30, 2008 – gain of $102.6 million) as the stronger U.S. dollar results in an increase in the relative value of the net assets in our downstream operations.

Future Income Tax

At the end of 2007, we had a net future income tax provision on our balance sheet totaling $86.6 million comprised of a $270.5 million provision for our mutual fund trust and other "flow through" entities and a net asset of $183.9 million for our corporate entities. For the three and nine months ended September 30, 2008, we have recorded a future income tax expense of $149.5 million and $32.5 million, respectively, 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 September 30, 2008 we have a net future tax liability on our balance sheet totaling $127.9 million comprised of a $218.9 million net asset for our corporate entities offset by a $346.8 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 deficiency on our risk management contracts.

Contractual Obligations and Commitments

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

		Maturity			
Annual Contractual Obligations *(000s)*	**Total**	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt(2)	**$ 1,465,823**	$ -	$ 1,199,773	$ 266,050	$ -
Interest on long-term debt(4)	**145,694**	18,319	110,901	16,474	-
Interest on Convertible Debentures(3)	**342,291**	16,427	130,402	123,563	71,899
Operating and premise leases	**21,925**	1,861	12,745	7,071	248
Purchase commitments(5)	**34,939**	28,019	6,920	-	-
Asset retirement obligations(6)	**1,029,168**	17,856	17,350	27,437	966,525
Transportation (7)	**5,803**	749	3,818	1,189	47
Pension contributions	**30,503**	286	3,631	5,301	21,285
Feedstock commitments	**859,853**	859,853	-	-	-
Total	**$ 3,935,999**	$ 943,370	$ 1,485,540	$ 447,085	$ 1,060,004

(1) As at September 30, 2008, we had entered into physical and financial contracts for upstream production with average deliveries of approximately 6,075 bbl/d for the remainder of 2008. We have also entered into financial contracts for downstream production of refined products with average deliveries of approximately 34,000 bbl/d for the remainder of 2008 and 20,000 bbl/d for the first half of 2009. We have also entered into financial contracts to minimize our exposure to fluctuating electricity prices. Please see Note 14 to the consolidated financial statements for further details.
(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. Only cash commitments are presented.
(4) Assumes constant foreign exchange rate.
(5) Relates to drilling commitments, AFE commitments and downstream purchase commitments.
(6) Represents the undiscounted obligation by period.
(7) Relates to firm transportation commitment on the Nova pipeline.

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.

Related Party Transactions

During the three and nine month periods ended September 30, 2008, Vitol purchased $200.2 million and $272.6 million respectively (three and nine month periods ended September 30, 2007, $128.5 million and $259.7 million, respectively) of Iraqi crude oil pursuant to the terms and conditions of the Supply and Offtake Agreement from a company in which a director of Harvest holds a minority equity interest. As at September 30, 2008, $3.4 million related to these purchases is included in Harvest's accounts payable and accrued liabilities. Additionally, $218.0 million is included in the total feedstock commitments disclosed at September 30, 2008. Subsequent to September 30, 2008, no further commitments have been incurred relating to crude oil purchases by Vitol from this private company.

CHANGE IN ACCOUNTING POLICIES

Effective January 1, 2008, we have adopted the requirements of the Canadian Institute of Chartered Accountants ("CICA") Section 3862 Financial Instruments – Disclosures, Section 3863 Financial Instruments – Presentation, and Section 1535 Capital Disclosures. The additional disclosures required as a result of adopting these new standards can be found in the notes to our consolidated financial statements for the three and nine months ended September 30, 2008.

In June 2007, the CICA issued Section 3031 – Inventories, which replaces the existing standard for inventories. This new standard provides additional disclosure requirements for inventories, and requires that inventories be valued at the lower of cost and net realizable value. The standard is effective for Harvest beginning January 1, 2008. Application of this new standard did not have a material impact on our financial statements.

LIQUIDITY AND CAPITAL RESOURCES

During the first nine months of 2008, cash flow from operating activities was $472.1 million, including a $98.9 million reduction in respect of changes in non-cash working capital. The non-cash working capital requirement is primarily due to increases of

$77.4 million and $51.9 million in accounts receivable and downstream inventories, respectively, offset by a $38.6 million increase in accounts payable. Cash flow from operating activities before changes in non-cash working capital and asset retirement expenditures totaled $577.8 million for the first nine months of 2008. We declared distributions of $410.7 million, incurred $220.2 million for capital expenditures and raised $106.5 million with our distribution re-investment plans resulting a net cash flow of $53.4 million excluding working capital adjustments. Our bank borrowings totaled $1,199.8 million at the end of the Third Quarter of 2008 as compared to $1,279.5 million at the end of 2007 essentially unchanged as the net proceeds from our issuance of $250 million of principal amount 7.5% Convertible Debentures on April 25, 2008 has been substantially offset by $127.6 million of net acquisition/disposition activity and the $98.9 million investment in non-cash working capital.

At the end of September 2008, we had $400.2 million of available borrowing capacity under our $1.6 billion Extendible Revolving Credit Facility as compared to $564.7 million at the beginning of the quarter. We continue to defer our request to extend the maturity date of our credit facility which currently has a maturity date of April 2010. With our cash flow risk management program, we enter pricing contracts and have limited our counterparties to the lenders in our syndicated credit facilities as the security provided in our credit agreement extends to these pricing contracts. This practice eliminates the potential requirement for margin calls and/or the pledging of collateral as well as limits the negotiation of events of default, all of which contribute to ensuring that these contracts improve our liquidity rather than exacerbate credit concerns.

Since December 31, 2007, the significant changes to our capital structure were:

- Issuance of $250 million principal amount of 7.50% Debentures due 2015 for aggregate cash consideration of $239.5 million,
- Issuance of 4,976,758 trust units pursuant to Harvest's Premium Distribution™ and Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "DRIP Plans") raising $106.5 million, and
- Issuance of 1,177,957 trust units on the conversion of $24.4 million of principal amount of Convertible Debentures including 1,166,593 in respect of the maturing of $24.2 million of principal amount of 10.5% convertible Debentures due January 31, 2008.

The following table summarizes our capital structure as at September 30, 2008 as well as at December 31, 2007:

(in millions)	**September 30, 2008**	December 31, 2007
DEBT		
Three Year Extendible Revolving Credit Facility	**$1,199.8**	$1,279.5
7 7/8 % Senior Notes Due 2011 (US$250 million)	**266.1** (1)	247.8(1)
Convertible Debentures, at principal amount		
10.5% Debentures Due 2008	**-**	24.3
9% Debentures Due 2009	**0.9**	1.0
8% Debentures Due 2009	**1.6**	1.7
6.5% Debentures Due 2010	**37.1**	37.1
6.4% Debentures Due 2012	**174.6**	174.6
7.25% Debentures Due 2013	**379.3**	379.3
7.25% Debentures Due 2014	**73.2**	73.2
7.50% Debentures Due 2015	**250.0**	-
Total Convertible Debentures	**916.7**	691.2
Total Debt	**2,382.6**	2,218.5
TRUST UNITS		
154,507,676 issued at September 30, 2008	**3,866.1**	
148,291,170 issued at December 31, 2007		3,736.1
TOTAL OF DEBT AND TRUST UNITS	**$6,248.7**	$5,954.6

(1) Face value converted at the period end exchange rate.

A full description of terms and covenants our $1.6 billion Extendible Revolving Credit Agreement, 7 7/8% Senior Notes as well as our Convertible Debentures are contained in the notes to our audited consolidated financial statements for the year ended December 31, 2007 and the Liquidity and Capital Resources section of our MD&A for the year ended December 31, 2007 filed on SEDAR at www.sedar.com.

The credit facility contains floating interest rates that are expected to range between 65 and 115 basis points over bankers' acceptance rates (currently 70 bps) depending on the ratio of our secured senior debt (excludes 7 7/8% Senior Notes and convertible debentures) to earnings before interest, taxes, depletion, amortization and other non-cash amounts ("EBITDA") with availability under this facility subject to:

Secured senior debt to EBITDA	3.0 to 1.0 or less
Total Debt to EBITDA	3.5 to 1.0 or less
Secured senior debt to capitalization	50% or less
Total Debt to capitalization	55% or less

At September 30, 2008, our Bank Debt to annualized EBITDA was 1.5 to 1.0, Total Debt (excludes convertible debentures) to annualized EBITDA was 1.8 to 1.0, while the secured senior debt to Total Capitalization was 25% and Total Debt to Total Capitalization was 31%.

The 7 7/8% Senior Notes contain certain covenants which among other things restrict our secured indebtedness to an amount 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 2007, this covenant limited secured indebtedness to approximately $1.85 billion.

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 September 30, 2008, these covenants would preclude the issuance of additional convertible debentures based on our then market capitalization.

Concurrent with the closing of the North Atlantic acquisition, we entered into a Supply and Offtake Agreement with Vitol Refining S.A. ("Vitol"), a third party related to the vendor of North Atlantic. The agreement provides for ownership of substantially all of the crude oil feedstock and refined product inventory at the refinery be retained by Vitol and granted Vitol the right and obligation to provide and deliver crude oil feedstock to the refinery as well as the right and obligation to purchase all refined products produced by the refinery. Effective January 2008, the sale of HSFO was removed from the Supply and Offtake Agreement and sold directly to a wholly-owned affiliate of one of the world's largest integrated oil and natural gas producers. For a more complete description of this Supply and Offtake Agreement, see the description of the Supply and Offtake Agreement in our Annual Information Form for the year ended December 31, 2007 filed on SEDAR at www.sedar.com. At the end of September 2008, we estimate that Vitol held inventories of VGO, crude oil feedstock (both delivered and in-transit) and refined products for resale valued at approximately $859.9 million which would have otherwise have been assets of Harvest. Effective April 19, 2008, both Harvest and Vitol Refining S.A. may terminate the Supply and Offtake Agreement by providing six month written notice.

Year-to-date in 2008, the trading value of our trust units ranged from a high of $26.00 in February to a low of $8.33 in October. This volatility in our trading value while reflecting weakness in refining margins has been significantly impacted by the global credit crunch, general slowing of worldwide economies, a financial de-leveraging of the equity markets and a roll back of commodity prices. At the end September 2008 approximately 70% of our Unitholders were non-residents of Canada which is up slightly from 66% at the end of 2007. The following summarizes the trading value of our trust units during 2008:

	Trading Price		
Month	**High**	**Low**	**Volume**
TSX Trading			
January 2008	$ 23.56	$ 20.48	10,474,631
February 2008	$ 26.00	$ 22.49	8,552,342
March 2008	$ 24.13	$ 22.00	9,638,750
April 2008	$ 24.94	$ 22.23	11,965,637
May 2008	$ 25.67	$ 22.15	14,019,461
June 2008	$ 25.77	$ 23.32	9,263,955
July 2008	$ 24.60	$ 19.32	10,210,064
August 2008	$ 21.75	$ 18.90	12,078,163
September 2008	$ 21.12	$ 15.99	9,834,707
October 2008	$ 17.69	$ 8.33	26,521,040
November 1 – 7, 2008	$ 13.27	$ 11.47	3,135,049

NYSE Trading (in US$)			
January 2008	$ 23.24	$ 20.00	18,167,009
February 2008	$ 25.70	$ 22.51	15,108,961
March 2008	$ 24.49	$ 21.44	17,099,323
April 2008	$ 24.82	$ 22.06	20,845,245
May 2008	$ 26.08	$ 21.75	24,871,749
June 2008	$ 25.28	$ 23.05	16,892,369
July 2008	$ 24.30	$ 18.80	23,625,243
August 2008	$ 20.55	$ 17.73	17,597,112
September 2008	$ 20.01	$ 15.17	24,126,064
October 2008	$ 16.69	$ 7.00	65,647,621
November 1 – 7, 2008	$ 11.55	$ 9.67	9,264,969

On October 20, 2008, the Toronto Stock Exchange approved our Normal Course Issuer Bid to purchase for cancellation, subject to daily limits, up to 10% of the outstanding Trust Units and Convertible Debentures not held by insiders on the open market at the prevailing market prices at the time of such purchase. While we believe that, from time to time, the market prices for these securities may not reflect the underlying value, purchases by Harvest may increase the proportionate interest of all remaining security holders while providing increased liquidity to security holders wishing to sell their securities. To date, their have been no such purchases.

Through a combination of cash from operating activities, unused credit capacity and the working capital provided by the Supply and Offtake Agreement, it is anticipated that we will have adequate liquidity to fund future operations and forecasted capital expenditures although cash from operating activities used to fund ongoing operations may reduce the amount of future distributions paid to unitholders.

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 future of our upstream operations relies on the 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 growth in profitability available by upgrading HSFO, enhancing our refining processes to handle a heavier more sour feedstock and/or expanding our refining capacity which is expected to benefit from the incremental economics of available with our existing infrastructure. 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, the amount of our distributions to Unitholders may be reduced. Should capital markets or incremental debt not be available to us, our ability to make the necessary expenditures to maintain or expand our assets may be impaired and result in reductions to future distributions paid to Unitholders. In our upstream business, it is not possible to distinguish between expenditures to maintain productive capacity and spending to increase productive capacity due to the numerous factors impacting reserve reporting and the natural decline in reservoirs. Accordingly, maintenance capital is not disclosed separately.

Our distributions will generally exceed the net income reported in our financial statements as a result of significant non-cash charges recorded in our income statement. In the first nine months of 2008, we recorded a $379.8 million provision in respect of depreciation and depletion based primarily on our historic costs of property, plant and equipment that does not accurately represent the fair value or replacement cost of the assets, nor do they affect cash generated in the current period. This charge results in significant differences to net income with no impact on cash from operating activities. Accordingly, we anticipate that over time our net income may fluctuate significantly from our cash flow from operating activities as well as distributions to unitholders. During the first nine months of 2008, our distributions to unitholders exceeded our net income of $133.4 million by $277.3 million as compared to the prior year where our distributions to unitholders exceeded our net income of $87.9 million by $377.7 million. In instances where our distributions exceed our net earnings, a portion of the distribution may represent a return of capital rather than a distribution of earnings. For the first nine months of 2008, our distributions declared totaled $410.7 million, representing 87% of cash from operating activities.

Management, together with the Board of Directors of Harvest, continually assess the level of our monthly distributions in light of commodity price expectations, currency exchange rates, production and throughput projections, operating cost forecasts, debt leverage and spending plans. Since November 2007, we have declared a monthly distribution of $0.30 per Trust Unit through

February 2009, a distribution level that reflects our expectations of future commodity prices and currency exchange rates as well as our future production and throughput volumes and operating costs.

Prior to January 1, 2011, the Trust is subject to tax on its taxable income less the portion that is paid or payable to the Unitholders at the end of each taxation year. For 2008, we anticipate that our distributions to Unitholders will be 100% taxable and that the Trust will have no taxable income. The following table summarizes the distributions declared, the proceeds from our distribution reinvestment programs as well as distributions as a percentage of cash from operating activities for the three and nine months ended September 30, 2008 and 2007:

	Three Months Ended September 30			Nine Months Ended September 30		
(000s except per Trust Unit amounts)	**2008**	2007	Change	**2008**	2007	Change
Distributions declared	$ 138,511	$ 166,271	(17%)	$ 410,678	$ 465,598	(12%)
Per Trust Unit	$ 0.90	$ 1.14	(21%)	$ 2.70	$ 3.42	(21%)
Distribution reinvestment proceeds	$ 35,153	$ 47,670	(26%)	$ 106,515	$ 135,414	(21%)
Distributions as a percentage of cash from operating activities	104%	87%	17%	87%	84%	3%

Throughout the first nine months of 2008, we declared monthly distributions of $0.30 per Trust Unit to Unitholders, compared to a $0.38 per Trust Unit distribution for the same period in 2007. For the three and nine months ended September 30, 2008, the total amount of distributions declared was $138.5 million and $410.7 million, respectively, which is 104% and 87%, respectively, of our cash from operating activities. The decrease in distributions declared of $27.8 million for the three months ended September 30, 2008 and $54.9 million for the nine months ended September 30, 2008 is primarily due to the decrease of $0.08 in the monthly distribution declared per Trust Unit, offset by an increase of approximately 8.1 million Trust Units outstanding.

OUTLOOK

For the full year of 2008, we forecast production volumes from our upstream operations to be at the low end of our guidance of 56,000 to 57,000 boe/d with operating costs expected to average $14.50 per boe with electric power and well servicing comprising approximately 50% of our costs. The price on approximately 65% of our expected Alberta electric power consumption is fixed at $56.69 per MWh through to the end of 2008. We continue to forecast our 2008 capital spending will total approximately $250 million in our upstream operations.

For our downstream operations, we expect that during the Fourth Quarter of 2008, our refinery throughput will average approximately 109,000 bbl/d and that our operating costs will continue to average approximately $2.00/bbl while we expect the cost of purchased energy to drop by approximately $5 million as compared to previous quarters, primarily due to anticipated weakness in the price of lower sulphur fuel oil consumed to provide heat to our refining processes. The completion of the visbreaker project early in the Fourth Quarter is expected to result in an improved yield of gasoline and distillate products, increase visbreaker unit throughput by approximately 2,000 bbl/d, and extend the visbreaker run-time between unit shutdowns for heater decoking. During 2008, we expect capital spending in our downstream operations will aggregate to $54 million.

During the Fourth Quarter of 2008, we expect a generally weaker commodity price environment will result in lower cash flow from our upstream operations and a significant reduction in the cash settlements from our price risk management program. As referred to the Cash Flow Risk Management section of this MD&A, we have contracts in place on 26,075 bbl/d of our WTI cash flow exposure for the Fourth Quarter 2008 which provide floors to our WTI price exposure at approximately US$53.85. With respect to our cash flow exposure related to refined product crack spreads, we have contracts in place for approximately 30% of our expected Fourth Quarter exposure. We also have currency exchange contracts on US$10.0 million per month through to December 2008 which caps our participation in Canadian dollar weakness beyond US$0.9479 per Cdn$1.00 which represents approximately 10% of our exposure to fluctuations in the US dollar to Canadian dollar exchange rate, prior to considering the offsetting exposure of our US dollar denominated 7 7/8% Senior Notes.

In July 2008, SNC Lavalin completed a preliminary evaluation of a broad range of refinery reconfigurations with the most economic case increasing throughput capacity to 190,000 bbl/d, comprised of a blend of heavy to medium gravity sour crude oil at a cost of approximately $2 billion in nominal 2008 dollars. SNC Lavalin's evaluation has also confirmed some low risk/high return enhancement opportunities to (1) increase the Isomax throughput to 42,000 bbl/d from 37,000 bbl/d, (2) increase the capacity of the crude unit to 120,000 bbl/d from 115,000 bbl/d, (3) revamp the crude unit and vacuum tower to improve the VGO recovery, (4) improve process heater energy efficiency, and, (5) enhance crude oil storage and blending capability. While the enhancement opportunities may be financed from operating cash flow, we engaged a financial advisor to search for a partner to provide financing for the $2 billion reconfiguration project. While the $2 billion reconfiguration project remains viable, we have now elected to defer the project and partnering process in light of the current uncertainty in global capital markets and a volatile commodity pricing environment.

For 2009, we are forecasting that our upstream operations will produce between 52,000 and 53,000 boe/d with a capital budget of $260 million, excluding acquisitions and dispositions, and expect operating costs to be approximately $15.00 per boe. Our capital budget includes the drilling of approximately 125 wells focusing primarily on our assets in British Columbia and Saskatchewan, plus a continued emphasis on our enhanced oil recovery projects and infrastructure investment. Following on the success of our reservoir pressure maintenance program at Hay River BC this year, our 2009 plans for this area will focus on a significant drilling program with 59 wells. In southeast Saskatchewan, we plan to continue to build on our development of Tilston, Souris Valley and Bakken trends with an estimated 46 wells to be drilled. We expect our 2009 production profile to consist of approximately 55% light to medium oil, 20% heavy oil and 25% natural gas.

Our downstream average daily throughput is expected to be approximately 112,000 bbl/d in 2009 with anticipated operating costs ranging from $2.00 to $2.20 per barrel. The 2009 capital spending plan aggregates to $62 million including $20 million on enhancement opportunities/strategic projects.

For the first six months of 2009, we have contracts in place on 20,000 bbl/d of our WTI cash flow exposure which provide floors to our WTI price exposure at approximately US$61.94 as well as refined product crack spread protection on approximately 18% of our expected exposure. We do not have any currency exchange rate contracts or electric power price contracts beyond December 2008.

While we do not forecast commodity prices nor refining margins, the following table reflects the sensitivity of our 2009 operations to changes in the following key factors to our business:

	Assumption		Change		Impact on Cash Flow	
WTI oil price (US$/bbl)	$	67.00	$	5.00	$	0.19 / Unit
CAD/USD exchange rate	$	0.80	$	0.05	$	0.43 / Unit
AECO daily natural gas price	$	8.00	$	1.00	$	0.18 / Unit
Refinery crack spread (US$/bbl)	$	9.80	$	1.00	$	0.33 / Unit
Upstream operating expenses (per boe)	$	15.00	$	1.00	$	0.12 / 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 as well as maintain our present level of distributions. We expect that the participation level in our distribution re-investment programs will range between 20% and 25% with non-Canadian ownership of our trust units being approximately 65% to 70%.

We manage our exposure to fluctuations in interest rates by maintaining a mix of short and longer term financing with the short term financing typically carrying floating interest rates and longer term financing (our $7^{7/8}$% Senior Notes and convertible debentures) carrying fixed rates of interest. Our short term financing consists of borrowings under our credit facilities and totals $1,199.8 million at September 30, 2008 which represents 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 credit if we extend (or renew) our credit facilities or enter into additional longer term financings. We have decided to defer extending the April 2010 maturity date on our $1.6 billion Extendible Revolving Credit Facility due the current condition of the global credit markets. With respect to further reducing our borrowings under our credit facility, we continue to monitor the high yield market as well as opportunities to issue additional trust units and convertible debentures.

Upon the maturing of our convertible debentures, we may elect to satisfy these obligation by issuing units rather than settling the obligations in cash with the maturity dates spread on the $916.7 million of principal amount of convertible debentures outstanding as follows: 2009 - $2.5 million; 2010 - $37.1 million; 2012 – $174.6 million; 2013 - $379.3 million; 2014 - $73.2 million and 2015 - $250 million. While not necessarily impacting 2008, we anticipate that as these convertible debentures mature, or are converted into trust units before their maturity date, we will be able to retire $916.7 million of principal amount of unsecured debt with equity issuances.

In our upstream business, we will continue to evaluate opportunities to acquire producing oil and/or natural gas properties as well as offer selected properties for divestment while striving to maintain or enhance our productive capability and improve our unit operating costs. In addition, we intend to be an active participant in the consolidation of the Canadian energy industry, including other royalty trusts.

As the changes to Canada's Income Tax Act to apply a 31.5% tax on distributions from publicly traded mutual fund trusts, including Harvest, have now been enacted with an effective date of January 1, 2011, we continue to search and validate various capital structures, balancing the benefits of the remaining years of tax efficient distributions against the longer term benefits of continuing with a growth strategy beyond the announced "normal growth" limitations.

SUMMARY OF QUARTERLY RESULTS

The following table and discussion highlights our Third Quarter of 2008 relative to the preceding seven quarters:

	2008			2007				2006
(000s except where noted)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenue, net of royalties	**$ 1,597,195**	$ 1,622,079	$ 1,377,352	$ 879,124	$ 1,031,514	$ 1,133,450	$ 1,025,512	$ 682,744
Net income (loss)	**$ 295,788**	$ (162,063)	$ (346)	$ (113,585)	$ 11,811	$ 6,248	$ 69,850	$ 1,533
Per Trust Unit, basic[1]	**$ 1.93**	$ (1.07)	$ -	$ (0.77)	$ 0.08	$ 0.05	$ 0.55	$ 0.01
Per Trust Unit, diluted[1]	**$ 1.73**	$(1.07)	$-	$ (0.77)	$ 0.08	$ 0.05	$ 0.55	$ 0.01
Cash from operating activities	**$ 133,493**	$ 210,534	$ 128,119	$ 87,998	$ 191,049	$ 251,218	$ 111,048	$ 140,543
Per Trust Unit, basic	**$ 0.87**	$ 1.39	$ 0.85	$ 0.60	$ 1.31	$ 1.88	$ 0.87	$ 1.21
Per Trust Unit, diluted	**$ 0.84**	$ 0.83	$ 0.83	$ 0.60	$ 1.22	$ 1.67	$ 0.84	$ 1.16
Distributions per Unit, declared	**$ 0.90**	$ 0.90	$ 0.90	$ 0.98	$ 1.14	$ 1.14	$ 1.14	$ 1.14
Total long term debt	**$ 2,284,664**	$ 2,105,998	$ 2,209,451	$ 2,172,417	$ 2,097,187	$ 1,987,352	$ 2,436,018	$ 2,488,524
Total assets	**$ 5,659,227**	$ 5,637,879	$ 5,574,528	$ 5,451,683	$ 5,585,651	$ 5,613,333	$ 5,800,346	$ 5,745,558

(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. Accordingly, since the acquisition of the downstream operations in the Fourth Quarter of 2006, our revenues have increased substantially and then throughout 2007 have remained relatively stable until the Fourth Quarter of 2007 when the refinery throughput decreased due to a planned shutdown for more than half of the quarter. Throughout 2008, net revenues have been the highest in Harvest's history due to strong commodity prices.

The growth in cash from operating activities is closely aligned with the trend in commodity prices for our upstream operations and reflects the cyclical nature of the downstream segment. In the Third Quarter of 2008, cash from operating activities has decreased from the previous quarter reflecting increased working capital requirements in our downstream business, a $2.60/bbl decrease in our upstream operating netback, which was partially offset by improved 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 and losses 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 substantively 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. In the First Quarter of 2008, future income tax recovery of $21.8 million was recorded as a result of the excess depreciation expense recorded over the amount of tax pool claims to be made; an additional recovery of $95.2 million was recorded in the Second Quarter of 2008 and an expense of $149.5 million was recorded in the Third Quarter of 2008. 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 since our acquisition of North Atlantic in the Fourth Quarter of 2006. The stability reflects moderate acquisition activity offset by a reduction in net book value associated with depletion and depreciation charges. The changes in total long term financial liabilities is primarily due to the impact of our acquisitions, offset by the issuance of Trust Units and the net cash surplus of cash from operating activities over distributions to Unitholders.

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, 2007 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 and nine month periods ended September 30, 2008 from those described in our annual MD&A.

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

Convergence of Canadian GAAP with International Financial Reporting Standards
In early 2008, Canada's Accounting Standards Board ("AcSB") announced that Canadian public reporting issuers will be required to report under International Financial Reporting Standards ("IFRS") beginning January 1, 2011. The adoption of IFRS is intended to bring more transparency and a higher degree of global comparability as IFRS has been adopted in more than 100 countries. In preparation of this move to IFRS, Harvest has retained an advisor who has completed a diagnostic review identifying the areas of Harvest's financial reporting likely to be most significantly affected by the transition. Harvest has also assigned staff to lead the conversion project with project sponsorship from the senior executive team and has assembled an IFRS steering committee consisting of senior personnel from various functional areas within the organization. During the Third Quarter of 2008, we have drafted our detailed project plan, and during the Fourth Quarter of 2008, the focus of the IFRS conversion project will be on finalization of our detailed project plan and the determination of Harvest accounting policies under IFRS using the diagnostic review that has been completed as a basis.

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062 Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. The new Section will be effective on January 1, 2009. Section 3062 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. We are currently evaluating the impact of the adoption of this new section, however do not expect a material impact on our Consolidated Financial Statements.

OPERATIONAL AND OTHER BUSINESS RISKS

Our financial and operating performance is subject to risks and uncertainties which include, but are not limited to: upstream operations, downstream operations, reserve estimates, commodity prices, ability to obtain financing, environmental, health and safety risk, regulatory risk, disruptions in the supply of crude oil and delivery of refined products, employee relations, and other risks specifically discussed previously in this MD&A. We intend to continue executing our business plan to create value for Unitholders by paying stable monthly distributions and increasing the net asset value per Trust Unit. All of our risk management activities are carried out under policies approved by the Board of Directors of Harvest Operations, and are intended to mitigate the risks noted above as follows:

The following summarizes the more significant risks of our upstream and downstream operations. See our Annual Information Form for a full description of these risks as well as risks associated with our royalty trust structure.

Operation of oil and natural gas properties:
- Applying a proactive management approach to our properties;
- Selectively adding skilled and experienced employees and providing encouragement and opportunities to maintain and improve technical competence; and

Operation of a refining and petroleum marketing business:
- Maintaining a proactive approach to managing the supply of feedstock and sale of refined products to ensure the continuity of supply of crude oil to the refinery and the delivery of refined products from the refinery;
- Allocating sufficient resources to ensure good relations are maintained with our non-unionized and unionized work force; and

Estimates of the quantity of recoverable reserves:
- Acquiring oil and natural gas properties that have high-quality reservoirs combined with mature, predictable and reliable production and thus reduce technical uncertainty;
- Subjecting all property acquisitions to rigorous operational, geological, financial and environmental review; and
- Pursuing a capital expenditure program to reduce production decline rates, improve operating efficiency and increase ultimate recovery of the resource-in-place.

Commodity price exposures:
- Maintaining a risk-management policy and committee to continuously review effectiveness of existing actions, identify new or developing issues and devise and recommend to the Board of Directors of Harvest Operations action to be taken;
- Executing risk management contracts with a portfolio of credit-worthy counterparties;
- Maintaining an efficient cost structure to maximize product netbacks; and

- Limiting the period of exposure to price fluctuations between crude oil prices and product prices by entering into contracts such that crude oil feedstock will be priced based on the price at or near the time of delivery to the refinery, which may be as much as 24 days subsequent to the time the feedstock is initially loaded onto the shipping vessel, thereby minimizing the time between the pricing of the feedstock and the refined products with the objective of maintaining margins.

Financial risk:
- Monitoring financial markets to ensure the cost of debt and equity capital is kept as low as reasonably possible;
- Retaining a portion of cash flows to finance capital expenditures and future property acquisitions; and
- Carrying adequate insurance to cover property and business interruption losses.

Environmental, health and safety risks:
- Adhering to our safety programs and keeping abreast of current industry practices for both the oil and natural gas industry as well as the refining industry; and
- Committing funds on an ongoing basis toward the remediation of potential environmental issues.

Changing government policy, including revisions to royalty legislation, income tax laws, and incentive programs related to the oil and natural gas industry:
- Retaining an experienced, diverse and actively involved Board of Directors to ensure good corporate governance; and
- Engaging technical specialists when necessary to advise and assist with the implementation of policies and procedures to assist in dealing with the changing regulatory environment.

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, 2007 as filed on SEDAR at www.sedar.com.

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 commonly used in the refining industry to reflect the net funds received from the sale of refined products after considering the cost to purchase the feedstock and is calculated by deducting purchased products for resale and processing from total revenue. Earnings From Operations is also commonly used in the petroleum and natural gas and refining industries to reflect operating results before items not directly related to operations.

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)		**September 30, 2008**		December 31, 2007
Assets				
Current assets				
Accounts receivable and other	**$**	**293,170**	$	215,803
Fair value of risk management contracts *[Note 14]*		**6,723**		16,442
Prepaid expenses and deposits		**12,910**		15,144
Inventories *[Note 4]*		**111,811**		58,934
		424,614		306,323
Property, plant and equipment *[Note 5]*		**4,273,078**		4,197,507
Intangible assets *[Note 6]*		**94,998**		95,075
Goodwill		**866,537**		852,778
	$	**5,659,227**	$	5,451,683
Liabilities and Unitholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities	**$**	**308,831**	$	270,243
Cash distribution payable		**46,352**		44,487
Current portion of convertible debentures *[Note 8]*		**2,505**		24,273
Fair value deficiency of risk management contracts *[Note 14]*		**163,123**		131,020
		520,811		470,023
Bank loan		**1,199,773**		1,279,501
7 7/8% Senior notes		**260,120**		241,148
Convertible debentures *[Note 8]*		**822,266**		627,495
Fair value deficiency of risk management contracts *[Note 14]*		**-**		35,095
Asset retirement obligation *[Note 7]*		**224,019**		213,529
Employee future benefits *[Note 13]*		**12,102**		12,168
Deferred credit		**550**		710
Future income tax		**127,938**		86,640
Unitholders' equity				
Unitholders' capital *[Note 9]*		**3,866,050**		3,736,080
Equity component of convertible debentures		**84,100**		39,537
Contributed surplus *[Note 10]*		**6,433**		-
Accumulated income		**380,244**		246,865
Accumulated distributions		**(1,751,027)**		(1,340,349)
Accumulated other comprehensive loss		**(94,152)**		(196,759)
		2,491,648		2,485,374
	$	**5,659,227**	$	5,451,683

Commitments, contingencies and guarantees *[Note 16]*
Subsequent events *[Note 17]*
See accompanying notes to these consolidated financial statements.

Approved by the Board of Directors:

((signed))
William D. Robertson
Director

((signed))
Hector J. McFadyen
Director

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

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

	Three Months Ended Sept 30, 2008	Three Months Ended Sept 30, 2007	**Nine Months Ended Sept 30, 2008**	Nine Months Ended Sept 30, 2007
Revenue				
Petroleum, natural gas, and refined product sales	**$ 1,670,463**	$ 1,088,320	**$ 4,809,107**	$ 3,350,479
Royalty expense	**(73,268)**	(56,806)	**(212,482)**	(160,003)
	1,597,195	1,031,514	**4,596,625**	3,190,476
Expenses				
Purchased products for processing and resale	**1,099,963**	747,010	**3,220,513**	2,087,948
Operating	**131,640**	133,926	**401,593**	372,837
Transportation and marketing	**12,415**	14,085	**36,790**	36,674
General and administrative *[Note 12]*	**2,493**	4,681	**28,280**	31,548
Realized net losses on risk management contracts	**94,498**	1,793	**225,216**	8,916
Unrealized net losses (gains) on risk management contracts	**(359,654)**	21,935	**6,331**	25,042
Interest and other financing charges on short term debt	**32**	606	**233**	4,986
Interest and other financing charges on long term debt	**38,063**	35,764	**109,113**	115,840
Depletion, depreciation, amortization and accretion	**124,795**	130,396	**379,834**	393,819
Foreign exchange loss (gain)	**7,662**	(16,102)	**22,372**	(98,460)
Large corporations tax and other tax	**(25)**	(39)	**471**	85
Future income tax (recovery) expense	**149,525**	(54,352)	**32,500**	123,332
	1,301,407	1,019,703	**4,463,246**	3,102,567
Net income for the period	**295,788**	11,811	**133,379**	87,909
Cumulative Translation Adjustment	**56,628**	(86,033)	**102,607**	(230,664)
Comprehensive income (loss) for the period	**$ 352,416**	**$** (74,222)	**$ 235,986**	**$** (142,755)
Net income (loss) per Trust Unit, basic *[Note 9]*	**$ 1.93**	$ 0.08	**$ 0.88**	$ 0.65
Net income (loss) per Trust Unit, diluted *[Note 9]*	**$ 1.73**	$ 0.08	**$ 0.88**	$ 0.65

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 (Loss) Income
At December 31, 2006	**$3,046,876**	**$ 36,070**	**$ -**	**$ 271,155**	**$ (730,069)**	**$ 46,873**
Adjustment arising from change in accounting policies	(49)	-	-	1,386	-	-
Issued for cash						
February 1, 2007	143,834	-	-	-	-	-
June 1, 2007	230,029					
Equity component of convertible debenture issuances						
7.25% Debentures Due 2014	-	13,100	-	-	-	-
Convertible debenture conversions						
9% Debentures Due 2009	220	-	-	-	-	-
8% Debentures Due 2009	456	(3)	-	-	-	-
6.5% Debentures Due 2010	882	(55)	-	-	-	-
10.5% Debentures Due 2008	2,999	(627)	-	-	-	-
6.40% Debentures Due 2012	122	(10)	-	-	-	-
7.25% Debentures Due 2013	244	(8)	-	-	-	-
7.25% Debentures Due 2014	157,139	(8,929)	-	-	-	-
Exercise of unit appreciation rights and other	400	-	-	-	-	-
Issue costs	(26,258)	-	-	-	-	-
Foreign currency translation adjustment	-	-	-	-	-	(230,664)
Net income	-	-	-	87,909	-	-
Distributions and distribution reinvestment plan	135,414	-	-	-	(465,598)	-
At September 30, 2007	**$3,692,308**	**$ 39,538**	**$ -**	**$ 360,450**	**$ (1,195,667)**	**$ (183,791)**
At December 31, 2007	**$3,736,080**	**$ 39,537**	**$ -**	**$ 246,865**	**$ (1,340,349)**	**$ (196,759)**
Equity component of convertible debenture issuances						
7.5% Debentures Due 2015	-	51,000	-	-	-	-
Convertible debenture conversions						
9% Debentures Due 2009	32	-	-	-	-	-
8% Debentures Due 2009	141	(1)	-	-	-	-
10.5% Debentures Due 2008	13	(3)	-	-	-	-
Redemption of convertible debentures						
10.5% Debentures Due 2008 *[Note 8]*	24,249	(6,433)	6,433	-	-	-
Exercise of unit appreciation rights and other	1,350	-	-	-	-	-
Issue costs	(2,330)	-	-	-	-	-
Foreign currency translation adjustment	-	-	-	-	-	102,607
Net income	-	-	-	133,379	-	-
Distributions and distribution reinvestment plan	106,515	-	-	-	(410,678)	-
At September 30, 2008	**$3,866,050**	**$ 84,100**	**$ 6,433**	**$ 380,244**	**$ (1,751,027)**	**$ (94,152)**

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(thousands of Canadian dollars)

	Three Months Ended Sept 30, 2008	Three Months Ended Sept 30, 2007	Nine Months Ended Sept 30, 2008	Nine Months Ended Sept 30, 2007
Cash provided by (used in)				
Operating Activities				
Net income for the period	**$ 295,788**	$ 11,811	**$ 133,379**	$87,909
Items not requiring cash				
Depletion, depreciation, amortization and accretion	**124,795**	130,396	**379,834**	393,819
Unrealized foreign exchange loss (gain)	**1,528**	29,463	**15,072**	(49,559)
Non-cash interest expense and amortization of finance charges	**4,000**	2,457	**10,040**	9,590
Unrealized loss (gain) on risk management contracts *[Note 14]*	**(359,654)**	21,935	**6,331**	25,042
Future income tax expense (recovery)	**149,525**	(54,352)	**32,500**	123,332
Unit based compensation expense (recovery)	**(6,653)**	(4,415)	**714**	4,462
Employee benefit obligation	**(404)**	(1,108)	**(67)**	(12)
Other non-cash items	**3**	21	**(33)**	27
Settlement of asset retirement obligations *[Note 7]*	**(3,006)**	(2,902)	**(6,761)**	(7,290)
Change in non-cash working capital	**(72,429)**	57,743	**(98,862)**	(34,005)
	133,493	191,049	**472,147**	553,315
Financing Activities				
Issue of Trust Units, net of issue costs	**(150)**	(553)	**(2,329)**	354,004
Issue of convertible debentures, net of issue costs	**-**	-	**241,600**	220,489
Bank borrowings (repayments), net	**165,348**	126,015	**(78,868)**	(366,355)
Financing costs	**-**	-	**-**	(273)
Cash distributions	**(102,825)**	(117,485)	**(302,299)**	(320,933)
Change in non-cash working capital	**5,930**	(2,050)	**9,601**	9,413
	68,303	5,927	**(132,295)**	(103,655)
Investing Activities				
Additions to property, plant and equipment	**(86,297)**	(85,791)	**(220,182)**	(297,253)
Business acquisitions	**(36,756)**	(140,518)	**(36,756)**	(170,782)
Property acquisitions (dispositions), net	**(95,374)**	1,140	**(90,825)**	22,252
Change in non-cash working capital	**17,280**	15,096	**9,295**	(14,382)
	(201,147)	(210,073)	**(338,468)**	(460,165)
Change in cash and cash equivalents	**$ 649**	$ (13,097)	**$ 1,384**	$ (10,505)
Effect of exchange rate changes on cash	**(649)**	(350)	**(1,384)**	499
Cash and cash equivalents, beginning of period	**-**	13,447	**-**	10,006
Cash and cash equivalents, end of period	**$ -**	$ -	**$ -**	$-
Interest paid	**$ 32,784**	$ 39,560	**$ 76,282**	$90,421
Large corporation tax and other tax paid	**$ (10)**	$ (79)	**$561**	$45

See accompanying notes to these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Period ended September 30, 2008
(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, 2007 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, 2008, Harvest adopted the following new Canadian Institute of Chartered Accountants ("CICA") accounting standards:

"Financial Instruments – Disclosure", section 3862 and "Financial Instruments – Presentation", section 3863. These new standards require increased disclosure on financial instruments, particularly with regard to the nature and extent of risks arising from financial instruments and how the entity manages those risks.

"Capital Disclosures", section 1535 requires the disclosure of information about an entity's objectives, policies and processes for managing capital; quantitative data about what the entity regards as capital; whether the entity has complied with any externally imposed capital requirements; and if it has not complied, the consequences of such non-compliance.

"Inventories", section 3031, which replaces the existing inventories standard. This new standard provides additional guidance with respect to the measurement and disclosure requirements for inventories, requiring inventories to be valued at the lower of cost and net realizable value. The adoption of this section did not have a material impact on our financial statements.

3. Acquisitions

(a) Private petroleum and natural gas corporation
On July 24, 2008, Harvest acquired all of the issued and outstanding shares of a private petroleum and natural gas corporation for $36.8 million net of working capital adjustments and transaction costs. The results of operations of this acquisition have been included in the consolidated financial statements since its acquisition date.

(b) Petroleum and natural gas assets
On September 8, 2008, Harvest acquired certain petroleum and natural gas assets in exchange for $130.8 million in cash plus our interest in two non-operated properties. The results of operations of these assets for total consideration of $136.3 million have been included in the consolidated financial statements since the acquisition date.

4. Inventories

		September 30, 2008		December 31, 2007
Petroleum products	**$**	**107,305**	$	55,036
Parts and supplies		**4,506**		3,898
Total inventories	**$**	**111,811**	$	58,934

5. Property, Plant and Equipment

	September 30, 2008			December 31, 2007		
	Upstream	**Downstream**	**Total**	Upstream	Downstream	Total
Cost	**$ 4,573,654**	**$ 1,282,947**	**$ 5,856,601**	$ 4,247,819	$ 1,164,310	$ 5,412,129
Accumulated depletion and depreciation	**(1,457,849)**	**(125,674)**	**(1,583,523)**	(1,142,345)	(72,277)	(1,214,622)
Net book value	**$ 3,115,805**	**$ 1,157,273**	**$ 4,273,078**	$ 3,105,474	$ 1,092,033	$ 4,197,507

General and administrative costs of $1.4 million have been capitalized during the three month period ended September 30, 2008 (three months ended September 30, 2007 – $1.8 million), which included a recovery of $1.3 million (three months ended September 30, 2007 – recovery of $1.0 million) related to the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan. For the nine month period ended September 30, 2008, $7.9 million (nine months ended September 30, 2007 – $8.4 million) of general and administrative costs have been capitalized, of which $0.3 million (nine months ended September 30, 2007 – $1.3 million) relate to the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan.

6. Intangible Assets

	September 30, 2008			December 31, 2007		
	Cost	**Accumulated Amortization**	**Net book value**	Cost	Accumulated Amortization	Net book value
Engineering drawings	**$ 94,714**	**$ (9,274)**	**$ 85,440**	$ 88,227	$ (5,330)	$ 82,897
Marketing contracts	**6,587**	**(1,920)**	**4,667**	6,136	(1,099)	5,037
Customer lists	**3,988**	**(781)**	**3,207**	3,714	(449)	3,265
Fair value of office lease	**931**	**(596)**	**335**	931	(428)	503
Financing costs	**7,300**	**(5,951)**	**1,349**	12,113	(8,740)	3,373
Total	**$ 113,520**	**$ (18,522)**	**$ 94,998**	$ 111,121	$ (16,046)	$ 95,075

7. 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 $1,029 million which will be incurred between 2008 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:

	September 30, 2008	December 31, 2007
Balance, beginning of period	**$ 213,529**	$ 202,480
Incurred on acquisition of a private corporation	**1,900**	1,629
Incurred on acquisition of Grand	**-**	4,416
Liabilities incurred	**2,689**	9,553
Revision of estimates	**(1,230)**	(6,088)
Liabilities settled through disposition	**-**	(3,708)
Liabilities settled	**(6,761)**	(13,090)
Accretion expense	**13,892**	18,337
Balance, end of period	**$ 224,019**	$ 213,529

Harvest has undiscounted asset retirement obligations of approximately $14.7 million relating to the refining and marketing assets. The fair value of this obligation cannot be reasonably determined because the assets currently have an indeterminate life.

8. Convertible Debentures

At September 30, 2008, 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, 2007. The following table summarizes the face value, carrying amount and fair value of the Convertible Debentures:

	September 30, 2008			December 31, 2007		
	Face Value	**Carrying Amount[(1)]**	**Fair Value**	Face Value	Carrying Amount[(1)]	Fair Value
9% Debentures Due 2009	**$ 944**	**$ 937**	**$ 1,269**	$ 976	$ 962	$ 1,806
8% Debentures Due 2009	**1,588**	**1,568**	**1,733**	1,728	1,692	2,022
6.5% Debentures Due 2010	**37,062**	**35,196**	**35,950**	37,062	34,653	35,950
10.5% Debentures Due 2008	**-**	**-**	**-**	24,258	24,273	24,258
6.40% Debentures Due 2012	**174,626**	**169,163**	**127,756**	174,626	168,325	148,432
7.25% Debentures Due 2013	**379,256**	**357,653**	**290,131**	379,256	355,145	344,895
7.25% Debentures Due 2014	**73,222**	**67,333**	**58,578**	73,222	66,718	65,892
7.5% Debentures Due 2015	**250,000**	**192,921**	**196,250**	-	-	-
	$ 916,698	**$ 824,771**	**$ 711,667**	$ 691,128	$ 651,768	$ 623,255

(1)Excluding the equity component.

On January 31, 2008, the 10.5% Debenture Due 2008 matured and Harvest elected to settle the obligation with the issuance of 1,166,593 Trust Units rather than settling the obligation in cash.

On April 25, 2008, Harvest issued $250 million principle amount of 7.5% Convertible Debentures for total net proceeds from the issue of $239.5 million. These debentures mature on May 31, 2015 and have a conversion price of $27.40.

9. Unitholders' Capital

(a) Authorized

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

(b) Number of Units Issued

	Nine months ended September 30,	
	2008	2007
Outstanding, beginning of period	**148,291,170**	122,096,172
Issued for cash		
February 1, 2007	**-**	6,146,750
June 1, 2007	**-**	7,302,500
Convertible debenture conversions		
9% Debentures Due 2009	**2,310**	15,881
8% Debentures Due 2009	**8,710**	28,307
6.5% Debentures Due 2008	**-**	27,967
10.5% Debentures Due 2008	**344**	81,478
6.40% Debentures Due 2012	**-**	2,542
7.25% Debentures Due 2013	**-**	7,574
7.25% Debentures Due 2014	**-**	5,753,310
Redemption of convertible debentures		
10.5% Debentures Due 2008	**1,166,593**	-
Distribution reinvestment plan issuance	**4,976,758**	4,969,051
Exercise of unit appreciation rights and other	**61,791**	10,801
Outstanding, end of period	**154,507,676**	146,442,333

(c) Per Trust Unit Information

The following tables summarize the net income and Trust Units used in calculating income per Trust Unit:

Net income		**Three months ended Sept 30, 2008**		Three months ended Sept 30, 2007		**Nine months ended Sept 30, 2008**		Nine months ended Sept 30, 2007
Net income, basic	**$**	**295,788**		11,811	**$**	**133,379**		87,909
Interest on convertible debentures		**19,322**		-		**-**		-
Net income, diluted[1]	**$**	**315,110**	$	11,811	**$**	**133,379**	$	87,909
Weighted average Trust Units								
Weighted average Trust- Units outstanding, basic		**153,605,340**		145,290,946		**151,826,541**		135,431,845
Effect of convertible debentures		**28,748,036**		-		**-**		-
Effect of Employee Unit Incentive Plans		**-**		1,106,567		**267,719**		857,094
Weighted average Trust Units outstanding, diluted[2]		**182,353,376**		146,397,513		**152,094,260**		136,288,939

(1) Net income, diluted excludes the impact of the conversions of certain of the convertible debentures for the three and nine month periods ended September 30, 2008 of nil and $50,132,000 respectively (three and nine months ended September 30, 2007 - $13,799,000 and $45,487,000), as the impact would be anti-dilutive.

(2) Weighted average Trust Units outstanding, diluted for the three and nine month periods ended September 30, 2008 does not include the unit impact of nil and 25,056,361 respectively for certain of the convertible debentures (three and nine months ended September 30, 2007 – 20,743,678 and 23,701,488) and 302,269 and nil respectively, for the Unit Appreciation Rights, as the impact would be anti-dilutive.

10. Contributed Surplus

Contributed surplus of $6.4 million has been recorded during the nine month period ended September 30, 2008 due to the maturity of the 10.5% Debentures Due 2008 and the resulting expiration of the conversion option which was previously recorded in equity component of convertible debentures.

11. Capital Structure

Harvest's primary objective in its management of capital resources is to ensure sufficient financial flexibility to access capital to fund its financial obligations as well as to fund future growth. Harvest considers its capital structure to comprise its credit facilities, 7⁷/⁸% Senior Notes, convertible debentures and unitholders' equity.

Harvest monitors its capital structure using the following non-GAAP financial ratios: bank debt to Twelve Month Trailing Earnings Before Interest, Taxes, Depreciation and Amortization and non-cash amounts ("EBITDA"), secured debt to net present value of our proved petroleum and natural gas reverses discounted at 10% and total debt to total debt plus unitholders' equity. Total debt includes borrowings under credit facilities plus our 7⁷/⁸% Senior Notes and principal amount of convertible debentures and unitholders' equity is adjusted to remove the equity component of convertible debentures.

Harvest's capital management strategy with regards to our bank debt is to maintain a bank debt to EBITDA ratio between 1.0 and 2.5 times. This ratio is calculated as follows:

		September 30, 2008		December 31, 2007
Cash provided by operating activities	**$**	**560,145**	$	641,313
Settlement of asset retirement obligations		**12,561**		13,090
Change in non-cash working capital		**82,241**		17,384
Interest paid		**133,813**		145,740
Large Corporations Tax and other taxes paid		**(588)**		(974)
Total EBITDA	**$**	**788,172**	$	816,553
Bank debt	**$**	**1,199,773**	$	1,279,501
Bank debt to EBITDA		**1.52**		1.57

With respect to its senior debt, Harvest's strategy is to target a ratio of secured debt to 65% of the net present value of its proved petroleum and natural gas reserves discounted at 10% (as determined on an annual basis) of less than 0.9 times. This is calculated as follows:

	September 30, 2008		December 31, 2007	
Secured debt (borrowings under Credit Facilities)	**$**	**1,199,773**	$	1,279,501
Proved petroleum and natural gas reserves (January 1, 2008 Net Present Value discounted at 10%)	**$**	**2,865,200**	$	2,865,200
65% of Proved petroleum and natural gas reserves	**$**	**1,862,380**	$	1,862,380
Secured debt to 65% of proved petroleum and natural gas reserves		**0.64**		0.69

Harvest targets its total debt to total debt plus unitholders' equity to be a ratio between 0.25 and 0.55 times calculated as follows:

	September 30, 2008		December 31, 2007	
Bank debt	**$**	**1,199,773**	$	1,279,501
7 7/8% Senior Notes		**260,120**		241,148
Principal amount of convertible debentures		**916,698**		691,128
Total Debt		**2,376,591**		2,211,777
Unitholders' equity (less equity component of convertible debentures)		**2,407,548**		2,445,837
Total debt plus unitholders' equity	**$**	**4,784,139**	$	4,657,614
Total debt to total debt plus unitholders' equity		**0.50**		0.47

Harvest's capital structure is limited by a covenant in its Convertible Debenture Indenture which currently restricts the issuance of additional convertible debentures to approximately $68 million. In addition, although Harvest's Trust Unit Indenture provides for the issuance of an unlimited number of Trust Units, the "normal growth guidelines" contained in Bill C-52 issued by the Government of Canada limits the future issuance of convertible debentures and Trust Units at September 30, 2008 to approximately $2.1 billion with any unused normal growth available for use prior to 2011. Included in this amount is approximately $590 million that the Trust may issue to replace debt held on October 31, 2006.

Harvest monitors its capital structure and makes adjustments according to market conditions to remain flexible while meeting its objectives as outlined above. Accordingly, Harvest may adjust its capital spending programs, adjust the amount of distributions paid to Unitholders, issue new Trust Units, convertible debentures or senior notes or repay existing debt. Harvest's capital management targets have remained unchanged during the nine month period ended September 30, 2008.

12. Employee Unit Incentive Plans

Trust Unit Rights Incentive Plan

As at September 30, 2008, a total of 5,040,686 (3,823,683 – December 31, 2007) Unit Appreciation Rights were outstanding under the Trust Unit Rights Incentive Plan at an average exercise price of $23.10 ($25.74 – December 31, 2007).

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

	Three months ended September 30, 2008			Year ended December 31, 2007		
	Unit Appreciation Rights		**Weighted Average Exercise Price**	Unit Appreciation Rights		Weighted Average Exercise Price
Outstanding beginning of period	**3,823,683**	**$**	**30.74**	3,788,125	$	30.81
Granted	**2,038,872**		**23.45**	576,383		29.03
Exercised	**(68,675)**		**25.67**	(92,775)		21.88
Forfeited	**(753,194)**		**29.09**	(448,050)		31.10
Outstanding before exercise price reductions	**5,040,686**		**28.11**	3,823,683		30.74
Exercise price reductions	**-**		**(5.01)**	-		(5.00)
Outstanding, end of period	**5,040,686**		**23.10**	3,823,683	$	25.74
Exercisable before exercise price reductions	**139,775**	**$**	**23.26**	138,350	$	22.72
Exercise price reductions	**-**		**(14.50)**	-		(9.38)
Exercisable, end of period	**139,775**	**$**	**8.76**	138,350	$	13.34

The following table summarizes information about Unit appreciation rights outstanding at September 30, 2008.

		Outstanding			Exercisable	
Exercise Price before price reductions	Exercise Price net of price reductions	At Sept 30, 2008	Weighted Average Exercise Price net of price reductions(1)	Remaining Contractual Life (1)	At Sept 30, 2008	Weighted Average Exercise Price net of price reductions(1)
$13.15-$18.90	$0.01-$18.63	45,600	$ 10.46	2.7	23,750	$ 2.95
$19.29-$25.37	$5.77-$24.38	1,957,028	21.43	4.3	108,425	13.56
$26.09-$31.96	$16.13-$26.45	1,594,258	20.89	3.3	7,600	19.10
$32.01-$37.56	$20.03-$29.69	1,443,800	28.20	2.6	-	-
$13.15-$37.56	$0.01-$29.69	5,040,686	$ 23.10	3.5	139,775	$ 8.76

(1) Based on weighted average Unit appreciation rights outstanding.

Unit Award Incentive Plan("Unit Award Plan")

At September 30, 2008, 380,846 Units were outstanding under the Unit Award Incentive Plan.

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

Number	Nine months ended September 30, 2008	Year ended December 31, 2007
Outstanding, beginning of period	**348,248**	306,699
Granted	**117,942**	56,132
Adjusted for distributions	**47,508**	48,280
Exercised	**(106,179)**	(37,072)
Forfeitures	**(26,673)**	(25,791)
Outstanding, end of period	**380,846**	348,248
Exercisable, end of period	**182,092**	168,401

Harvest has recognized compensation expense (recovery) of $(6.5) million and $1.6 million for the three and nine months ended September 30, 2008 respectively ($4.1 million recovery and $6.4 million expense – three and nine months ended September 30, 2007), including non cash compensation expense (recovery) of $(6.7) million and $0.6 million for the three and nine months ended September 30, 2008 respectively ($4.5 million recovery and $4.2 million expense – three and nine months ended September 30, 2007), related to the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan. This is reflected in general and administrative expense in the consolidated statements of income.

13. Employee Future Benefit Plans

Defined Contribution Pension Plan

Total expense for the defined contribution plan is equal to Harvest's required contributions and was $0.2 million and $0.5 million for the three and nine month periods ended September 30, 2008, respectively ($0.2 million and $0.5 million – three and nine months ended September 30, 2007)

Defined Benefit Plans

Estimated pension and other benefit payments to plan participants, which reflect expected future service, expected to be paid from 2008 to 2017 are summarized in the commitment table [see Note 16].

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

	Three Months ended September 30, 2008		Three Months ended September 30, 2007	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Current service cost	**$ 838**	**$ 92**	$ 762	$ 92
Interest costs	**668**	**87**	592	79
Expected return on assets	**(698)**	**-**	(667)	-
Net benefit plan expense	**$ 808**	**$ 179**	$ 687	$ 171

	Nine Months ended September 30, 2008		Nine Months ended September 30, 2007	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Current service cost	**$ 2,515**	**$ 276**	$ 2,282	$ 276
Interest costs	**2,003**	**261**	1,780	237
Expected return on assets	**(2,094)**	**-**	(2,001)	-
Net benefit plan expense	**$ 2,424**	**$ 537**	$ 2,061	$ 513

14. Financial Instruments and risk management contracts

Financial instruments of Harvest consist of cash, accounts receivable, accounts payable and accrued liabilities, cash distribution payable, bank loan, risk management contracts, convertible debentures and the 7⁷/⁸% Senior Notes. The carrying value and fair value of these financial instruments at September 30, 2008 is disclosed below by financial instrument category, as well as any related gains or losses and interest income or expense for the nine month period ended September 30, 2008:

	Carrying Value	Fair Value	Gains/ (Losses)	Interest Income/ (Expense)	Other Income/ (Expense)
Loans and Receivables					
Accounts receivable	$ 293,170	$ 293,170	$ -	$ 125 (2)	$ -
Liabilities Held for Trading					
Net fair value of risk management contracts	156,400	156,400	(231,547) (3)	-	-
Other Liabilities					
Accounts payable	308,831	308,831	-	-	-
Cash distribution payable	46,352	46,352	-	-	-
Bank loan	1,199,773	1,199,773	-	(40,959) (4)	(2,024) (4)
7⁷/⁸% Senior Notes	260,120 (1)	235,454	-	(16,231) (5)	-
Convertible debentures	$ 824,771	$ 711,667	$ -	$ (50,132) (5)	$ -

(1) The face value of the 7⁷/⁸% Senior Notes at September 30, 2008 is $266.1 million (U.S. $250 million).
(2) Included in petroleum, natural gas, and refined product sales in the statement of income and comprehensive income.
(3) Included in risk management contracts - realized and unrealized gains/(losses) in the statement of income and comprehensive income.
(4) Included in interest and other financing charges on short term/long term debt in the statement of income and comprehensive income. The amortization of financing fees related to this liability is included in amortization of deferred finance charges in the statement of cash flows.
(5) Included in interest and other financing charges on short term/long term debt in the statement of income and comprehensive income. The non-cash interest expense relating to the accretion of premiums, discounts or transaction costs that are netted against these liabilities are included in non-cash interest in the statement of cash flows.

The fair values of the convertible debentures and the 7⁷/⁸% Senior Notes are based on quoted market prices as at September 30, 2008. The risk management contracts are recorded on the balance sheet at their fair value, accordingly, there is no difference between fair value and carrying value. The bank loan is recorded at amortized cost, but as there are no transaction costs associated with our bank debt and the financing costs are included in intangible assets, there is no difference between the carrying value and the fair value. Due to the short term nature of accounts receivable, accounts payable and cash distribution payable, their carrying values approximate their fair values.

(a) Risk Exposure

Harvest is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Harvest is also exposed, to a lesser extent, to credit risk on accounts receivable and counterparties to price risk management contracts and to liquidity risk relating to our debt.

(i.) Credit Risk

Upstream Accounts Receivable

Accounts receivable in our upstream operations are due from crude oil and natural gas purchasers as well as joint venture partners in the petroleum and natural gas industry and are subject to normal industry credit risks. Concentration of credit risk is mitigated by having a broad customer base, which includes a significant number of companies engaged in joint operations with Harvest. Harvest periodically assesses the financial strength of its crude oil and natural gas purchasers and will adjust its marketing plan to mitigate credit risks. This assessment involves a review of external credit ratings; however, if external ratings are not available, Harvest requests a guarantee from the parent company that does have a credit rating. If this is not possible, Harvest performs an internal credit review based on the purchaser's past financial performance. The credit risk associated with joint venture partners is mitigated by reviewing the credit history of partners and requiring some partners to provide cash prior to incurring significant capital costs on their behalf. As well, most agreements have a provision that enables us to use the proceeds from the sale of production that would otherwise be taken in kind by the partner to offset against amounts owing from the partner that are in default. Generally, the only instances of impairment are when a purchaser or partner is facing bankruptcy or extreme financial distress.

Risk Management Contract Counterparties

Harvest is also exposed to credit risk from the counterparties to our risk management contracts. This risk is managed by diversifying Harvest's risk management portfolio among a number of counterparties and limiting those counterparties to lenders in our syndicated credit facilities; we have no history of impairment with these counterparties.

Downstream Accounts Receivable

The Supply and Offtake Agreement entered into in conjunction with the purchase of the refinery exposed Harvest to the credit risk of Vitol Refining S.A. ("Vitol") as all feedstock purchases and the majority of product sales are made with Vitol under this agreement. Harvest mitigates this risk by requiring that Vitol maintain a minimum B+ credit rating as assessed by Standard and Poors. If the credit rating falls below this line, additional security is required to be supplied to Harvest. This credit risk is also mitigated by the amounts owing to Vitol for feedstock purchases that are offset against amounts receivable from Vitol for product sales with the balance being net settled. Harvest is in a net payable position with Vitol at September 30, 2008 and accordingly the outstanding balance is included in current trade accounts payable in the liability liquidity table below.

Harvest's policy is to manage its credit risk by dealing with only financially sound customers, based on an evaluation of the customer's financial condition. At September 30, 2008, Harvest had an accounts receivable balance with one customer of $24.0 million resulting from the sale of refined product, representing approximately 22% of total downstream accounts receivable. This customer is an integrated multinational oil and gas company with an AA public credit rating.

Our maximum exposure to credit risk relating to the above classes of financial assets at September 30, 2008 is the carrying value of accounts receivable. The table below provides an analysis of our current financial assets and the age of our past due but not impaired financial assets by type of credit risk.

	Current AR	Overdue AR			
		≤ 30 days	> 30 days, ≤ 60 days	> 60 days, ≤ 90 days	> 90 days
Upstream Accounts Receivable	$ 148,955	$ 2,077	$ 969	$ 1,191	$ 21,495
Risk Management Contract Counterparties	937	-	-	-	-
Downstream Accounts Receivable	107,716	4,928	1,189	428	3,285
Total	**$** 257,608	**$** 7,005	**$** 2,158	**$** 1,619	**$** 24,780

(ii.) Liquidity Risk

Harvest is exposed to liquidity risk due to our borrowings under our credit facilities and 7⁷/⁸% Senior Notes with repayment requirements. This risk is mitigated by managing the maturity dates on our obligations, complying with covenants and managing our cash flow by entering into price risk management contracts. Additionally, when we enter into price risk management contracts we select counterparties that are also lenders in our syndicated credit facility, using the security provided in our credit agreement to extend to our risk management contracts eliminating the requirement for margin calls and the pledging of collateral.

The following table provides an analysis of our financial liability maturities based on the remaining terms of our liabilities as at September 30, 2008 and includes the related interest charges:

	≤1 year	>1 year ≤3 years	>4 years ≤5 years	>5 years	Total
Trade accounts payable	$ 308,831	$ -	$ -	$ -	$ 308,831
Distributions payable	46,352	-	-	-	46,352
Settlements of risk management contracts(1)	147,516	-	-	-	147,516
Bank loan and interest	13,052	1,268,771	-	-	1,281,823
Convertible debentures interest(2)	16,427	130,402	123,563	71,899	342,291
7⁷/⁸% Senior Notes and interest	5,266	41,903	282,524	-	329,693
Pension contributions	286	3,631	5,301	21,285	30,503
Asset retirement obligations	17,856	17,350	27,437	966,525	1,029,168
Total	**$** 555,586	**$**1,462,057	**$** 438,825	**$** 1,059,709	**$**3,516,177

(1) This value is determined using the relevant forward prices as of September 30, 2008. Additionally, only those contracts that are currently in a deficiency position are presented herein and the offsetting effect of contracts that are in an asset position is not reflected.

(2) Convertible debentures are typically converted into Trust Units prior to maturity or are redeemed for Trust Units at maturity by Harvest; therefore, only the interest portion is represented in the table above.

(iii.) Market Risks and Sensitivity Analysis

Harvest is exposed to three types of market risks: interest rate risk, foreign currency exchange rate risk and commodity price risk. How these risks arise, how they are managed and how Harvest's net income and other comprehensive income could be affected by changes in the underlying risk variables are presented below.

We have performed sensitivity analysis on the three types of risks identified, assuming that the volatility of the risks over the next quarter will be similar to that experienced in the past year. Harvest has determined that a reasonably possible price or rate variance over the next reporting period for a given risk variable can be estimated by calculating two standard deviations for each three month period in the last year for the relevant daily price/rate settings and using an average of the standard deviation as a reasonable estimate of the expected variance. This variance is then applied to the relevant period end rate or price to determine a reasonable percentage increase and decrease in the risk variable which can then be applied to the outstanding risk exposure at period end. Using 12 months of data, we factor in the seasonality of our business and the price volatility therein. At this time, we have not adjusted the data for any unusual or extreme situations but should one arise, the data would be adjusted accordingly.

Interest rate risk

Harvest is exposed to interest rate risk on its bank borrowings as interest rates are determined in relation to floating market rates plus an incremental charge based on secured debt to EBITDA. Harvest's convertible debentures and 7⁷/⁸% Senior Notes have fixed interest rates and therefore do not have any additional interest rate risk. Harvest manages its interest rate risk by targeting appropriate levels of debt relative to its expected cash flow from operations.

During the three and nine month periods ended September 30, 2008, interest charges on bank loans aggregated to $12.5 million and $41.0 million, reflecting effective interest rates of 3.92% and 4.21% respectively.

At September 30, 2008, if interest rates had decreased by 10% with all other variables held constant, after-tax net income for the period would have been $9.0 million higher, as a result of lower interest expense on variable rate borrowings. If interest rates had increased by 10%, with all other variables held constant, the after-tax net income would have been $9.0 million higher. This unexpected increase in net income results from the Prime lending rate remaining constant over the quarter resulting in a forward interest rate that is less than Harvest's effective interest rate throughout the period.

Foreign currency exchange rate risk

Harvest is exposed to the risk of changes in the U.S. dollar exchange rate on its U.S. dollar denominated revenues as well as Canadian dollar revenues that are based on a U.S. dollar commodity price. In addition, Harvest's 7⁷/⁸% Senior Notes are denominated in U.S. dollars (U.S.$250 million) and interest on these notes is payable semi-annually in U.S. dollars and accordingly the principal and any interest payable at the balance sheet date are also subject to currency exchange rate risk. Harvest is also exposed to currency exchange rate risk on its net investment in a self sustaining subsidiary that uses a U.S. dollar functional currency. Harvest manages these exchange rate risks by occasionally entering into fixed rate currency exchange contracts on future U.S. dollar payments and U.S. dollar sales.

At September 30, 2008, if the U.S. dollar strengthened or weakened by 5% relative to the Canadian dollar, the impact on net income and other comprehensive income due to the translation of monetary financial instruments would be as follows:

	Impact on			
		Net Income		Other Comprehensive Income
U.S. Dollar Exchange Rate - 5% increase	$	(13,484)	$	(24,122)
U.S. Dollar Exchange Rate - 5% decrease	$	13,484	$	24,122

As mentioned above, Harvest's wholly owned subsidiary North Atlantic Refining LP operates with a U.S. dollar functional currency which gives rise to currency exchange rate risk on North Atlantic's Canadian dollar denominated monetary assets and liabilities, such as Canadian dollar bank accounts and accounts receivable and payable, as follows:

	Impact on			
		Net Income		Other Comprehensive Income
Canadian Dollar Exchange Rate - 5% increase	$	(11,708)	$	635
Canadian Dollar Exchange Rate - 5% decrease	$	11,708	$	(635)

Commodity Price Risk

Harvest uses price risk management contracts to manage a portion of its crude oil, natural gas and refined product sales price exposure and power costs. As many of these contracts are denominated in U.S. dollars, we also enter into fixed rate currency exchange contracts. These contracts are recorded on the balance sheet at their fair value as of the balance sheet date, with changes from the prior period's fair value recorded in net income for the period. These fair values are generally determined as the difference between the stated fixed price of the contract and an expected future price of the underlying asset. Variances in expected future prices expose us to commodity price risk as changes will result in a gain or loss that we will realize on settlement of these contracts. This risk is mitigated by continuously monitoring the effectiveness of these contracts.

If the following changes in expected forward prices were applied to the fair value of risk management contracts in place at September 30, 2008, net income would be impacted as follows:

		Impact on NI	
Contract	**% Change**	**Due to % increase**	**Due to % decrease**
Heating Oil NYMEX	15%	$ (64,426)	$ 64,426
Heating Oil NYMEX - Crack	30%	(3,906)	3,906
RBOB Gasoline NYMEX – Crack	150%	(2,132)	2,132
#6 (1%) HFO Platts	15%	(29,011)	29,004
#6 (1%) HFO Platts – Crack	25%	909	(909)
West Texas Intermediate	15%	(8,853)	7,607
Alberta Power Pool	50%	3,155	(3,155)
Currency Forwards	5%	(1,593)	219
Total		**$ (105,857)**	**$ 103,230**

(b) Fair Values

At September 30, 2008, the net fair value deficiency reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $156.4 million ($149.7 million – December 31, 2007), which was included in the balance sheet as follows: fair value of risk management contracts (current assets) $6.7 million, fair value deficiency of risk management contracts (current liabilities) $163.1 million.

The following is a summary of Harvest's risk management contracts outstanding, along with their fair value at September 30, 2008:

Quantity	Type of Contract	Term	Average Price	Fair value
Crude Oil Price Risk Management				
6,000 bbl/d	WTI 3-way contract	Oct. 08 – Dec. 08	US$62.00 - $87.53 ($72.00)[a]	$ (11,802)
75 bbl/d	WTI Swap	Oct. 08 – Dec. 08	Cdn$95.01	(114)
				$ (11,916)
Refined Product Price Risk Management				
10,000 bbl/d	NYMEX heating oil 3-way contract	Oct. 08 – Dec. 08	US$60.90 - $93.31 ($81.06)[b][h]	$ (29,077)
6,000 bbl/d	Platt's fuel oil 3-way contract	Oct. 08 – Dec. 08	US$43.00 - $63.21 ($51.67)[c]	(11,227)
2,000 bbl/d	NYMEX heating oil collar	Oct. 08 – Dec. 08	US$79.80 - $91.35[d] [h]	(6,166)
2,000 bbl/d	Platt's fuel oil collar	Oct. 08 – Dec. 08	US$51.00 - $58.68[e]	(4,664)
12,000 bbl/d	NYMEX heating oil 3-way contract	Jan. 09 – Jun. 09	US$72.59 - $98.73 ($86.52)[f] [h]	(65,009)
8,000 bbl/d	Platt's fuel oil 3-way contract	Jan. 09 – Jun. 09	US$49.75 - $65.89 ($57.38)[g]	(29,980)
				$ (146,123)
Natural Gas Price Risk Management				
276 GJ/d	Fixed price – natural gas contract	Oct. 08 – Dec. 08	Cdn$4.16[i]	$ (94)
500 GJ/d	AECO natural gas 3-way contract	Oct. 08 – Dec. 08	Cdn$7.51	48
				$ (46)
Electricity Price Risk Management				
35 MWh	Electricity price swap contracts	Oct. 08 – Dec. 08	Cdn $56.69	**$ 1,929**
Refined Product Crack Spread Risk Management				
2,000 bbl/d	Platt's fuel oil crack swap	Oct. 08 – Dec. 08	US($16.50)	$ 388
6,000 bbl/d	NYMEX heating oil crack swap	Oct. 08 – Dec. 08	US$14.63	(4,424)
6,000 bbl/d	NYMEX RBOB crack swap	Oct. 08 – Dec. 08	US$10.00	4,358
				$ 322
Foreign Currency Exchange Rate Risk Management				
$10,000,000/month	U.S./Cdn dollar collar	Oct. 08 – Dec. 08	1.000 Cdn/US- 1.055 Cdn/US[j]	**(566)**
Total net fair value deficiency of risk management contracts				**$ (156,400)**

(a) If the market price is below $62.00, price received is market price plus $10.00; if the market price is between $62.00 and $72.00, the price received is $72.00; if the market price is between $72.00 and the ceiling of $87.53, the price received is market price; if the market price is over the ceiling of $87.53, price received is $87.53.

(b) If the market price is below $60.90, price received is market price plus $20.16; if the market price is between $60.90 and $81.06, the price received is $81.06; if the market price is between $81.06 and the ceiling of $93.31, the price received is market price; if the market price is over the ceiling of $93.31, price received is $93.31.

(c) If the market price is below $43.00, price received is market price plus $8.67; if the market price is between $43.00 and $51.67, the price received is $51.67; if the market price is between $51.67 and the ceiling of $63.21, the price received is market price; if the market price is over the ceiling of $63.21, price received is $63.21.

(d) If the market price is below $79.80, price received is $79.80; if the market price is between $79.80 and $91.35, the price received is market price; if the market price is over the ceiling of $91.35, price received is $91.35.

(e) If the market price is below $51.00, price received is $51.00; if the market price is between $51.00 and the ceiling of $58.68, the price received is market price; if the market price is over the ceiling of $58.68, price received is $58.68.

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

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

(h) 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).

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

(j) If the market price is below $1.000, price received is $1.000; if the market price is between $1.000 and the ceiling of $1.055, the price received is market price; if the market price is over the ceiling of $1.055, price received is the stated ceiling price.

For the three and nine months ended September 30, 2008, the total unrealized gain/loss recognized in the consolidated statement of income and comprehensive income was a gain of $359.7 million and a loss of $6.3 million respectively (a loss of $21.9 million and a loss of $25.0 million – three and nine months ended September 30, 2007), 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.

15. Segment Information

Harvest operates in Canada and has two reportable operating segments, Upstream and Downstream. Harvest's upstream operations consist of development, production and subsequent sale of petroleum, natural gas and natural gas liquids, while its downstream operations include the purchase of crude oil, the refining of crude oil, the sale of the refined products including a network of retail operations and the supply of refined products to commercial and wholesale customers.

	Downstream[1] Three months ended Sept 30,		Upstream[1] Three months ended Sept 30,		Total Three months ended Sept 30,	
	2008	2007	**2008**	2007	**2008**	2007
Results of Continuing Operations						
Revenue[2]	**$ 1,214,898**	$ 789,612	**$ 455,565**	$ 298,708	**$ 1,670,463**	$ 1,088,320
Royalties	**-**	-	**(73,268)**	(56,806)	**(73,268)**	(56,806)
Less:						
Purchased products for resale and processing	**1,099,963**	747,010	**-**	-	**1,099,963**	747,010
Operating	**58,326**	53,737	**73,314**	80,189	**131,640**	133,926
Transportation and marketing	**8,560**	10,673	**3,855**	3,412	**12,415**	14,085
General and administrative	**345**	522	**2,148**	4,159	**2,493**	4,681
Depletion, depreciation, amortization and accretion	**17,195**	17,280	**107,600**	113,116	**124,795**	130,396
	$ 30,509	$ (39,610)	**$ 195,380**	$ 41,026	**$ 225,889**	$ 1,416
Realized net losses on risk management contracts					**(94,498)**	(1,793)
Unrealized net (losses) gains on risk management contracts					**359,654**	(21,935)
Interest and other financing charges on short term debt, net					**(32)**	(606)
Interest and other financing charges on long term debt					**(38,063)**	(35,764)
Foreign exchange gain (loss)					**(7,662)**	16,102
Large corporations tax and other tax					**25**	39
Future income tax recovery (expense)					**(149,525)**	54,352
Net income					**$ 295,788**	$ 11,811
Total Assets[3]	**$ 1,670,107**	$ 1,499,663	**$ 3,982,397**	$ 4,085,988	**$ 5,659,227**	$ 5,585,651
Capital Expenditures						
Development and other activity	**$ 17,199**	$ 12,468	**$ 69,098**	$ 73,323	**$ 86,297**	$ 85,791
Business acquisitions	**-**	-	**36,756**	140,518	**36,756**	140,518
Property acquisitions (dispositions), net	**-**	-	**95,374**	(1,140)	**95,374**	(1,140)
Total expenditures	**$ 17,199**	$ 12,468	**$ 201,228**	$ 212,701	**$ 218,427**	$ 225,169
Property, plant and equipment						
Cost	**$ 1,282,947**	$ 1,146,661	**$ 4,573,654**	$ 4,230,426	**$ 5,856,601**	$ 5,377,087
Less: Accumulated depletion and depreciation	**(125,674)**	(57,535)	**(1,457,849)**	(1,032,039)	**(1,583,523)**	(1,089,574)
Net book value	**$ 1,157,273**	$ 1,089,126	**$ 3,115,805**	$ 3,198,387	**$ 4,273,078**	$ 4,287,513
Goodwill						
Beginning of period	**$ 181,025**	$ 191,916	**$ 676,795**	$ 656,248	**$ 857,820**	$ 848,164
Addition (reduction) to goodwill	**7,900**	(12,717)	**817**	20,546	**8,717**	7,829
End of period	**$ 188,925**	$ 179,199	**$ 677,612**	$ 676,794	**$ 866,537**	$ 855,993

(1) Accounting policies for segments are the same as those described in the Significant Accounting Policies
(2) Of the total downstream revenue above, two customers represent sales of $769.9 million and $193.1 million, respectively (three months ended September 30, 2007 – one customer represented $632.3 million). No other single customer within either division represents greater than 10% of Harvest's total revenue.
(3) Total Assets on a consolidated basis as at September 30, 2008 includes $6.7 million (September 30, 2007 - $22.2 million) relating to the fair value of risk management contracts.
(4) There is no intersegment activity.

	Downstream[1] Nine months ended Sept 30, 2008	2007	Upstream[1] Nine months ended Sept 30, 2008	2007	Total Nine months ended Sept 30, 2008	2007
Results of Continuing Operations						
Revenue[2]	**$ 3,504,443**	$ 2,474,044	**$ 1,304,664**	$ 876,435	**$ 4,809,107**	$ 3,350,479
Royalties	**-**	-	**(212,482)**	(160,003)	**(212,482)**	(160,003)
Less:						
Purchased products for resale and processing	**3,220,513**	2,087,948	**-**	-	**3,220,513**	2,087,948
Operating	**182,864**	148,019	**218,729**	224,818	**401,593**	372,837
Transportation and marketing	**26,558**	27,075	**10,232**	9,599	**36,790**	36,674
General and administrative	**1,514**	1,224	**26,766**	30,324	**28,280**	31,548
Depletion, depreciation, amortization and accretion	**50,438**	54,854	**329,396**	338,965	**379,834**	393,819
	$ 22,556	$ 154,924	**$ 507,059**	$ 112,726	**$ 529,615**	$ 267,650
Realized net losses on risk management contracts					**(225,216)**	(8,916)
Unrealized net (losses) gains on risk management contracts					**(6,331)**	(25,042)
Interest and other financing charges on short term debt, net					**(233)**	(4,986)
Interest and other financing charges on long term debt					**(109,113)**	(115,840)
Foreign exchange gain (loss)					**(22,372)**	98,460
Large corporations tax and other tax					**(471)**	(85)
Future income tax recovery (expense)					**(32,500)**	(123,332)
Net income					**$ 133,379**	$ 87,909
Total Assets[3]	**$ 1,670,107**	$ 1,499,663	**$ 3,982,397**	$ 4,085,988	**$ 5,659,227**	$ 5,585,651
Capital Expenditures						
Development and other activity	**$ 31,845**	$ 27,222	**$ 188,337**	$ 270,031	**$ 220,182**	$ 297,253
Business acquisitions	**-**	-	**36,756**	170,782	**36,756**	170,782
Property acquisitions (dispositions), net	**-**	-	**90,825**	(22,252)	**90,825**	(22,252)
Total expenditures	**$ 31,845**	$ 27,222	**$ 315,918**	$ 418,561	**$ 347,763**	$ 445,783
Property, plant and equipment						
Cost	**$ 1,282,947**	$ 1,146,661	**$ 4,573,654**	$ 4,230,426	**$ 5,856,601**	$ 5,377,087
Less: Accumulated depletion and depreciation	**(125,674)**	(57,535)	**(1,457,849)**	(1,032,039)	**(1,583,523)**	(1,089,574)
Net book value	**$ 1,157,273**	$ 1,089,126	**$ 3,115,805**	$ 3,198,387	**$ 4,273,078**	$ 4,287,513
Goodwill						
Beginning of period	**$ 175,983**	$ 209,930	**$ 676,795**	$ 656,248	**$ 852,778**	$ 866,178
Addition (reduction) to goodwill	**12,942**	(30,731)	**817**	20,546	**13,759**	(10,185)
End of period	**$ 188,925**	$ 179,199	**$ 677,612**	$ 676,794	**$ 866,537**	$ 855,993

(1) *Accounting policies for segments are the same as those described in the Significant Accounting Policies*

(2) *Of the total downstream revenue above, two customers represent sales of $2,397.0 million and $487.2 million, respectively (nine months ended September 30, 2007 – one customer represented $2,106.8 million). No other single customer within either division represents greater than 10% of Harvest's total revenue.*

(3) *Total Assets on a consolidated basis as at September 30, 2008 includes $6.7 million (September 30, 2007 - $22.2 million) relating to the fair value of risk management contracts.*

(4) *There is no intersegment activity.*

16. 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. 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 September 30, 2008:

(a) North Atlantic has a Supply and Offtake Agreement with Vitol Refining S.A. This agreement 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 for a minimum period of up to two years commencing October 19, 2006, Vitol Refining S.A. will be granted the right and obligation to provide crude oil feedstock for delivery to the refinery, as well as the right and obligation to purchase substantially all refined products produced by the refinery. As such, at September 30, 2008, North Atlantic had commitments totaling approximately $859.9 million ($600.3 million – September 30, 2007) in respect of future crude oil feedstock purchases and related transportation from Vitol Refining S.A.

The following is a summary of Harvest's contractual obligations and commitments as at September 30, 2008:

	Payments Due by Period						
	2008	2009	2010	2011	2012	Thereafter	Total
Debt repayments [1]	$ -	$ -	$1,199,773	$ 266,050	$ -	$ -	$1,465,823
Capital commitments[2]	28,019	6,920	-	-	-	-	34,939
Operating leases[3]	1,861	6,779	5,966	5,206	1,865	248	21,925
Pension contributions[4]	286	1,583	2,048	2,454	2,847	21,285	30,503
Transportation agreements[5]	749	2,318	1,500	714	475	47	5,803
Feedstock commitments[6]	859,853	-	-	-	-	-	859,853
Contractual obligations	$ 890,768	$ 17,600	$1,209,287	$ 274,424	$ 5,187	$ 21,580	$2,418,846

(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) Relating to drilling contracts, AFE commitments, equipment rental contracts and environmental capital projects.
(3) Relating to building and automobile leases.
(4) Relating to expected contributions for employee benefit plans [see Note 13].
(5) Relating to oil and natural gas pipeline transportation agreements.
(6) Relating to crude oil feedstock purchases and related transportation costs [see Note 16 (a) above].

17. Subsequent Events

Subsequent to September 30, 2008, Harvest declared a distribution of $0.30 per unit for Unitholders of record on November 24, 2008, December 31, 2008, January 23, 2009, and February 24, 2009.

Between October 1, 2008 and November 7, 2008, an additional $202.7 million was committed to the purchase of feedstock inventory under the Supply and Offtake Agreement held with Vitol Refining S.A. [see table in Note 16].

On October 20, 2008, Harvest announced that the Toronto Stock Exchange ("TSX") has accepted Harvest's Notice of Intention to commence a Normal Course Issuer Bid (the "Bid") to purchase trust and convertible debenture units for cancellation, from time to time, as Harvest considers advisable. The maximum number of securities to be purchased pursuant to the Bid represents 10% of the issued and outstanding Securities, which are not held by insiders of the Trust, on October 20, 2008.

18. Related Party Transactions

During the three and nine month periods ended September 30, 2008, Vitol Refining S.A. purchased $200.2 million and $272.6 million respectively ($128.5 million and $259.7 million of Iraqi crude oil - three and nine month periods ended September 30, 2007) of Iraqi crude oil at fair market value for processing by Harvest, which had been sourced from a private corporation of which a director of Harvest is also a director and holds a minority ownership interest. As at September 30, 2008, $3.4 million related to these transactions are included in accounts payable and accrued liabilities.

At September 30, 2008, there is $218.0 million included in our feedstock purchase commitments with Vitol Refining S.A. in respect of Iraqi crude oil to be purchased from this same private corporation of which a director of Harvest is also a director and holds a minority ownership interest [See Note 16].

19. Comparatives

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