SELECTED INFORMATION

The table below provides a summary of our financial and operating results for the three and nine month periods ended September 30, 2007 and 2006.

	Three Months Ended September 30			Nine Months Ended September 30		
($000s except where noted)	**2007**	2006	Change	**2007**	2006	Change
Revenue, net[1]	**1,007,786**	312,864	222%	**3,156,518**	677,424	366%
Cash From Operating Activities	**191,049**	143,597	33%	**553,315**	367,342	51%
Per trust unit, basic	**$ 1.31**	$ 1.35	(3%)	**$ 4.09**	$ 3.79	8%
Per trust unit, diluted	**$ 1.22**	$ 1.31	(7%)	**$ 3.74**	$ 3.67	2%
Net Income[2]	**11,811**	107,768	(89%)	**87,909**	134,513	(35%)
Per trust unit, basic	**$ 0.08**	$ 1.01	(92%)	**$ 0.65**	$ 1.39	(53%)
Per trust unit, diluted	**$ 0.08**	$ 0.99	(91%)	**$ 0.65**	$ 1.38	(53%)
Distributions declared	**166,271**	123,112	35%	**465,598**	333,813	39%
Distributions declared, per trust unit	**$ 1.14**	$ 1.14	-%	**$ 3.42**	$ 3.39	1%
Distributions declared as a percentage of Cash From Operating Activities	**87%**	86%	1%	**84%**	91%	(7%)
Bank debt				**1,205,119**	591,189	104%
Senior debt				**241,628**	279,425	(14%)
Convertible debentures[3]				**650,440**	235,114	177%
Total long-term financial liabilities[3]				**2,097,187**	1,105,728	90%
Total assets				**5,585,651**	4,076,771	37%
UPSTREAM OPERATIONS						
Daily Production						
Light to medium oil (bbl/d)	**27,401**	28,394	(3%)	**27,342**	27,136	1%
Heavy oil (bbl/d)	**14,217**	13,919	2%	**14,845**	14,003	6%
Natural gas liquids (bbl/d)	**2,219**	2,595	(14%)	**2,350**	2,111	11%
Natural gas (mcf/d)	**96,737**	103,618	(7%)	**98,682**	91,379	8%
Total daily sales volumes (boe/d)	**59,961**	62,178	(4%)	**60,984**	58,480	4%
Cash capital expenditures	**73,323**	129,054	(43%)	**270,031**	286,523	(6%)
DOWNSTREAM OPERATIONS						
Average daily throughput (bbl/d)	**103,983**	-	n/a	**111,052**	-	n/a
Aggregate throughput (mbbl)	**9,566**	-	n/a	**30,317**	-	n/a
Average Refining Margin (US$/bbl)	**3.08**	-	n/a	**10.57**	-	n/a
Cash capital expenditures	**12,468**	-	n/a	**27,222**	-	n/a

(1) Revenues are net of royalties and risk management activities

(2) Net Income includes a future income tax recovery of $54.4 million for the three months ended September 30, 2007 and a future tax expense of $123.3 million for the nine months ended September 30, 2007. Please see Note 14 to the Consolidated Financial Statements for further information.

(3) Includes current portion of Convertible Debentures.

Q3 MESSAGE TO UNITHOLDERS

SUSTAINABLE GROWTH STRATEGY

One of Harvest's unique advantages is our willingness and ability to quickly react and evolve to address challenges and changes within our business. We have faced several substantial changes over the past twelve months that have effectively transformed the industry. Through this, we have continued to evolve and drive forward with our plan to grow Harvest into a leading integrated and competitive oil and gas company.

Over the past five years since our initial public offering, we have followed our value principles and successfully assembled a unique suite of assets that would be very difficult if not impossible to replicate today. Our asset base is predominantly large pools of light/medium and heavy crude oil which have significant opportunity for sustainable development, and are complemented by our very long-life refining and marketing assets. We have structured our organization to benefit from vertical integration, and as a result, have a unique inventory of future internal development opportunities in the upstream and downstream business segments that we can invest in to generate attractive rates of return. Given our size, liquidity and integrated structure, we are well positioned to supplement our internal portfolio with value-added acquisitions that help drive Sustainable Growth.

UPSTREAM SEGMENT

In response to the challenges we face in western Canada to control escalating costs and offset natural declines, we are looking longer term and building Harvest for the future. Our commitment to Sustainable Growth has driven us to focus on improving the long-term recovery from our upstream assets, which consist of large hydrocarbon deposits that can be technically enhanced to improve and increase the recovery of the resource. We have a number of assets where we are implementing and optimizing long-life primary and secondary recovery through more active reservoir management.

Resource Potential

- We have over 2 billion barrels of conventional original-oil-in-place (OOIP), and an incremental 1 billion barrels of oil sands OOIP. This provides us with an excellent source of long-term development opportunities with potential for enhancing future cash flow and oil recovery, and the flexibility to pursue these opportunities as the price and cost environment allow.
- Over 1,000 drilling locations have been identified on our existing portfolio of properties, representing a 4-5 year development plan based on our current capital budget levels. Year to date in 2007 we have drilled 161 gross wells achieving a 98% success rate.
- We continue to seek opportunities to consolidate assets that complement and enhance our existing portfolio of assets, specifically those with identified opportunity for performance improvement through future development or optimization. We have been pleased with the performance to date of the heavy oil assets acquired in December 2006 and February 2007, and with the results and performance of the assets we added from the Grand Petroleum acquisition which closed in the third quarter.

In late October, the Alberta government announced dramatic changes to the province's existing royalty framework which will take effect January 1, 2009. These changes impose more punitive royalty rates for higher productivity wells and during periods of high commodity prices, resulting in a disincentive for investment. Despite this negative event for the entire oil and gas sector in Alberta, the impact to Harvest's current production is relatively neutral and could actually be marginally positive. This is because less than half of our cash flow is generated in Alberta, between 25-30% of our Alberta production is from freehold lands which are not impacted by the changes and predominantly due to our high percentage of long-life, lower productivity wells which were less significantly affected and in some cases will see reduced royalty rates.

Long Term Resource Projects & Enhanced Oil Recovery (EOR)

- **Wainwright, AB** – Technical evaluation of a commercially viable EOR pilot project involving an Alkaline Surfactant Polymer (ASP) flood has been completed, and we are in the process of sourcing necessary equipment with plans for implementation of a full scale pilot in 2008. Our technical work of the potential recovery from this large 100% working interest Sparky medium gravity oil pool (133mmboe net

Harvest OOIP) indicates pool-wide recovery factors could exceed 50%, compared to current (end of third quarter) recovery factors of approximately 35%.

- **Bellshill Lake, AB** - New water injection scheme to be implemented in the Ellerslie Formation has the potential to add incremental medium oil, up to 16mmboe which is a potential increase of approximately 125% over booked proved plus probable reserves as at December 31, 2006. Harvest has a 99% working interest in the Bellshill Lake Ellerslie unit that contains an estimated 216 mmboe net Harvest OOIP with a recovery factor to the end of the third quarter of 49%. Infrastructure modifications will be undertaken in 2008 to initiate the first phase of this improved recovery project.
- **Hayter, AB** – Harvest has initiated testing of solvent injection (2007), acid gas injection (2007) and enhanced water injection (anticipated in 2008) pilots to determine the most effective enhanced recovery technique for this large (138mmboe net Harvest OOIP) Dina heavy oil resource with low recovery factor (approximately 20% of the OOIP) to the end of the third quarter.
- **Kindersley, SK** – Harvest has been working with a third party research organization to evaluate the potential incremental recovery from our 79% working interest Eagle Lake Viking light oil pool utilizing enhanced waterflood technology. This large light oil resource contains an estimated 80 mmboe of OOIP with a recovery factor through the end of the third quarter of approximately 28%.
- **Hay River, BC** – Our Hay River property has over 200 mmboe of original resource in place with only 8% recovery to date. Our primary focus in the winter of 2008 will be to increase water injection to maintain reservoir pressure, thus ensuring the long term recovery potential of this large, medium gravity oil resource.
- **Oil Sands** – We have approximately 47,000 net acres of oil sands leases, including 29,400 acquired through 2006 and 2007 in the Red Earth area of northern Alberta, an emerging oil sands region. Ongoing activity at Red Earth includes the drilling of strat test evaluation wells to confirm the estimated 1 billion bbl of OOIP resource and identify the optimum drainage architecture and recovery technology to be applied. Harvest produces approximately 3,000 boepd of light (37-39° API) gravity crude in the Red Earth area that could be used as a blending diluent for any oilsands production, thereby eliminating the need to purchase more expensive condensate and improving overall economics.
- **CO_2 (Carbon dioxide) Flooding** - A proven method for enhancing the recovery of medium and light oil reservoirs, CO_2 flooding represents an excellent technology for large pools of hydrocarbons that have low recovery factors to date. We estimate that 40% of our oil asset base is applicable to miscible and immiscible CO_2 flooding, a view which is supported by a third party engineering firm. If fully implemented when suitable CO_2 infrastructure and delivery systems are in place, this technology could result in an incremental 8-15% oil recovery over current primary recovery techniques.
- **Coal Bed Methane (CBM)** – Within our portfolio, we have 125,000 net acres of land through the CBM corridor in west central Alberta, and will focus on retaining large CBM interests for development as infrastructure comes available and economics permit. To date in 2007, Harvest has participated in 5 gross CBM wells as we delineate the potential of this resource, bringing our total gross CBM well count to 9 wells.

The benefit of these projects and developments will be realized through both incremental production in the near term as well as increased future reserve bookings in the longer term. We have the technical focus and team to succeed in finding new opportunities and replenishing declines, and we are proactively establishing ourselves to unlock the value of our assets today and in the years to come.

Exploration Activities

Historically Harvest has not initiated exploration activities but has been involved primarily through agreements that allow for participation in successful drilling, which reduces potential cost and downside. However, over the past twelve months, we have built a team to evaluate and execute on those exploration activities offering an attractive risk / reward balance. To date, our team has been successful in delivering attractive results with our relatively small exploratory program. Examples of our success are demonstrated in southeast Saskatchewan, Markerville, central Alberta and Lloydminster.

- **Southeast Saskatchewan** – In addition to our ongoing drilling and development activities, this is an area that exemplifies our exploration efforts. We have assembled a significant land base through property acquisition and crown land purchases, shot extensive 3-D seismic, drilled exploratory wells and successfully identified new light oil pools at Hazelwood, Kennedy and Kenosee on a year over year basis. Our most recent discovery at Kenosee (2006) currently has over 10 horizontal wells drilled to date and production of approximately 650 boepd.

- **Markerville** – As a result of internally generated prospects, several exploratory wells have recently been drilled in the area and resulted in a new Ellerslie gas pool discovery. A 100% Harvest working interest follow-up location to the initial discovery well has confirmed an extension to the pool. Initial test data on the most recent well indicate a productive capability in the order of 500 boepd including liquids. We are evaluating 3-5 additional locations as a result of our exploration success, to be executed as part of our 2008 program.
- **Central Alberta** - An exploratory well drilled encountered significant net gas pay, and initial test data would indicate that it has a productive capability in the order of 800 boepd including liquids. Harvest has a 100% working interest in this well, and has identified at least one follow-up location for 2008, with the potential to downspace further to maximize recovery.
- **Lloydminster** – A successful exploration well in 2005 identifying a LLoydminster heavy oil pool has led to the drilling of 27 horizontal wells through 2006 and year to date 2007 resulting in current production of 1,500 boepd.

DOWNSTREAM OPERATIONS

Complementing our impressive upstream asset base is our very long-life downstream refining and marketing business. We process medium sour crude oil which is a very similar quality to the oil produced in our upstream business creating a financially integrated business between the upstream and the downstream, and a natural hedge. Being an integrated company with the ability to generate significant free cash flow differentiates Harvest, enhances our financial performance and helps diversify our revenue and cash flow.

The broader energy industry, including the refining business, is subject to seasonality which results in price variations throughout the year. This effect was very evident in the third quarter, as refining margins and crack spreads fell considerably from levels experienced in the second quarter, reducing the cash flow contribution we realized from the downstream. Refining margins for the first nine months of 2007 averaged $10.57 per bbl, which exceeds our original budget, despite a third quarter average of $3.08 per bbl. This reduction was largely driven by a decrease in gasoline (approximately 31% of our product slate) margins which typically occurs during the third quarter. We are seeing a seasonal recovery in distillate (approximately 42% of our product slate) margins as we approach winter and the heating oil season. This will help overall refining margins in the short-term. We also expect to see further strengthening in early 2008 as the summer driving season improves gasoline cracks.

Refinery Investment Opportunities

The weak refining margin environment that prevailed during the latter half of the third quarter gave us a unique opportunity to accelerate a turnaround on the crude unit and vacuum units originally scheduled for the second quarter of 2008 into the fourth quarter of 2007. Our ability to accelerate the turnaround on very short notice and assemble the required materials and personnel is evidence of the skill and expertise of our downstream team. The refinery is expected to return to full production at the beginning of December, with no major maintenance, shutdowns or turnarounds planned during 2008.

A significant advantage that we recognized with the North Atlantic acquisition is the opportunity to make incremental discretionary investments in the refinery and generate very attractive rates of return. Through our annual capital investment budget, we undertake discretionary projects designed to improve reliability and throughput, enhance margins and reduce costs. These smaller projects can be supplemented by more substantial opportunities that have the potential to create significant value.

- **Visbreaker Expansion** – This project has a direct impact on margins by effectively upgrading approximately 1,500 bbl/d of heavy fuel oil into higher value distillate and gasoline products. The first phase is underway and expected to be complete by the fourth quarter of 2008. The project has very attractive economics, with payout expected in about one year. A potential second phase expansion, which would upgrade an additional 3,000 bbl/d of heavy fuel oil, is in preliminary development.

- **Expansion Program** – In concert with the visbreaker expansion, this project would see refinery throughput increased 10%, generating an additional 2% gasoline and distillate yield from the heavy fuel oil, as well as providing increased flexibility in gasoline blending and reduced hydrocracker feed procurement.
- **Delayed Coker** – Estimates indicate this 4 -5 year project would require between US$400 and $600 million and would effectively eliminate heavy fuel oil production, improving the gasoline / distillate yield by 25%. We could also do a larger and more extensive coker project which would enable the refinery to run lower gravity, less expensive crude oil feedstock.
- **Major Refinery Expansion** – With a plot of 476 acres of land and existing infrastructure able to handle further capacity, the refinery's production could effectively be doubled with an investment of approximately US$1B and a 4-5 year time horizon. This potential for growth efficiency via expansion provides attractive economics relative to a new build development.

Focus on Safety & Environment

Consistent with our values and standard business practices, we run all of our facilities - in the upstream and downstream – using responsible practices to ensure the protection of people and the environment. Safety is at the core of our operations and is of utmost importance as we strive to always protect our people, our neighbors and the environment that we all share. Since our acquisition of North Atlantic on October 19, 2006 to November 7, 2007, our refinery has operated for approximately 1.4 million person-hours without a lost time accident, which is a new safety record for this facility. This meaningful statistic is just one indicator of our commitment to safety, environmental and social responsibility. Three quarters of our refined product slate are environmentally clean fuels with very low sulphur content, which means we do not need to make additional investments in the refinery in order to bring it up to current or future scheduled environmental standards. Significant investment has been made at North Atlantic over the past decade to bring the refinery into compliance with regulations governing clean air and minimizing our environmental footprint, as well as continued efforts focused on being a good and responsible corporate citizen in an environmentally and socially responsible manner. In addition, North Atlantic has been chosen as one of Canada's Top 100 Employers for the past three years.

DISTRIBUTIONS

Building our business for Sustainable Growth requires us to continually assess and evolve our strategy to ensure an appropriate balance between our cash flow, distributions to Unitholders, capital investment requirements and debt levels. As part of the Sustainable Growth strategy, our monthly distribution has been adjusted to C$0.30 per trust unit.

Given the uncertain and ever challenging environment for producers in western Canada along with the volatility inherent in the downstream business, maintaining flexibility is extremely important. Our Sustainable Growth strategy positions us very well to take advantage of attractive investment opportunities we have identified within our upstream and downstream businesses; reduce debt levels so that we can better weather uncertainty and grow through acquisition; and enhance our overall sustainability with long term growth. We have declared this distribution for a four month period.

Distribution Declaration Details

The distributions declared are based on forecast commodity price levels and operating performance that are consistent with the current environment.

Record Date	Ex-Distribution Date	Payment Date	$Cdn Distribution Amount
November 21, 2007	November 19, 2007	December 17, 2007	$0.30
December 31, 2007	December 27, 2007	January 15, 2008*	$0.30
January 24, 2008	January 22, 2008	February 15, 2008	$0.30
February 22, 2008	February 20, 2008	March 17, 2008	$0.30

*Taxable in the 2007 tax year

The Cdn$0.30 per unit is equivalent to approximately U.S.$0.32 per unit if converted using a Canadian/U.S. dollar exchange rate of 1.07. For U.S. beneficial holders, the U.S. dollar equivalent distribution will be based upon the actual Canadian/U.S. exchange rate applied on the payment date and will be net of any Canadian withholding taxes that may apply.

FUTURE OUTLOOK

We create value through the entrepreneurial growth of our assets and the efficient development and operation of those assets. With a revised and sustainable distribution level, we have positioned Harvest to create further value for our Unitholders from our existing assets, but also to pursue future potential opportunities to add to our unique and diversified portfolio.

- **2008 Upstream** – We are budgeting $225 million in annual capital expenditures, weighted towards oil properties in order to maximize returns in an environment of high world oil prices and reflecting our predominantly oil prone asset base. We have focused and reduced our capital budget to ensure that investments provide the most attractive rates of return and are directed to the best opportunities available. Based on this level of capital spending, we anticipate 2008 production volumes to average 55,000 boepd, with operating costs to range between $12.50 and $13 per boe. Royalties as a percentage of 2008 revenue are expected to be consistent with our recent historical rates of approximately 19%.
- **2008 Downstream -** We are budgeting $63 million in annual capital expenditures, with approximately two-thirds directed towards discretionary projects and $25 million of that directed towards completion of the visbreaker expansion project. Approximately one-third will be used for sustaining capital and maintenance projects. With no planned shutdowns or turnarounds during the year, we anticipate 2008 refinery throughput to average approximately 113,000 bbl/d. Our 2008 per barrel operating costs are expected to be consistent with those realized in 2007, as increased throughputs, improved energy efficiencies and containment of local currency inflation are expected to fully offset projected increases in purchased energy and power prices.
- **Debt Levels -** Building our business for Sustainable Growth requires us to continually assess and evolve our strategy to maintain an appropriate balance between the distributions we pay out to Unitholders, our capital investment requirements, as well as our current debt position. We had approximately $395 million of committed undrawn bank lines at the end of the quarter, which provides improved flexibility to undertake acquisitions or other value added projects. Through 2008, we will target lower bank debt levels to further increase our flexibility.
- **Price Risk Management -** Although we do enjoy an asset base that has product and geographic diversity to mitigate volatility and seasonality, we recognize that we are subject to variable commodity prices. As a result, we continue to employ a disciplined price risk management program that helps to minimize cash flow volatility. We now have hedges in place on approximately 85% of our net after royalty expected oil and liquids production in 2008, and 60% in the first half of 2009. We also have contracts in place for approximately 20% of our refinery cracks in 2008 and the first half of 2009. In many cases, these hedges allow us to lock in prices and margins at higher prices than what has been realized in 2007 and prior years.

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.

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, 2006 and 2005, our MD&A for the year ended December 31, 2006 as well as our interim consolidated financial statements and notes for the three and nine month periods ended September 30, 2007 and 2006. The information and opinions concerning our future outlook are based on information available at November 8, 2007.

When reviewing our 2007 results and comparing them to 2006, readers should be cognizant that the 2007 results include nine months of operations from our acquisition of Viking Energy Royalty Trust ("Viking") in February 2006, Birchill Energy Ltd. ("Birchill") in August 2006 and North Atlantic Refining Ltd. ("North Atlantic") in October 2006 and two months from our acquisition of Grand Petroleum Inc. ("Grand") in August 2007 whereas the comparative results in 2006 include only eight months of operations from our acquisition of Viking and two months of operations from our acquisition of Birchill. This significantly impacts the comparability of our operations and financial results for the three month and nine month periods ended September 30, 2007 to the comparative periods in the prior year.

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: 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, production volumes, reserve volumes and revenues are reported on a gross basis, before deduction of crown and other royalties, unless otherwise stated.

In this MD&A, we use certain financial reporting measures that are commonly used as benchmarks within the oil 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 company or trust. When these measures are used, they are defined as "non-GAAP" 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 reporting measures.

Historically, we used the non-GAAP measure of Funds From Operations (defined as cash from operating activities before changes in non-cash working capital, settlement of asset retirement obligations and one time transaction costs) to analyze operating performance, leverage and liquidity. Commencing with this MD&A, we now use cash from operating activities which appears on our Statement of Cash Flows and is adjusted for the effect of changes in non-cash working capital, cash settlement of asset retirement obligations and one time transaction costs.

Consolidated Financial and Operating Highlights – Third Quarter 2007

- Cash from operating activities totaled $191.0 million, an increase of $47.5 million over the prior year primarily due to a reduction in cash settlements on risk management contracts, the realization of currency exchange gains and reduced working capital requirements.
- Upstream operations provided $147.9 million of cash, reflecting stable production and higher commodity prices offset by continuing high operating costs which include turnaround costs at processing facilities.
- Downstream operations reflect significantly reduced margins as the increased costs of crude oil feedstock did not fully flow through to higher gasoline and distillate prices and we commenced a planned shutdown of a portion of the refinery.
- Crystallized a $43.5 million currency exchange gain on US$492.7 million bank borrowing and settled other commodity price risk management contracts for a net loss of $1.8 million.
- Closed our acquisition of Grand Petroleum Inc. on July 26, 2007 for aggregate consideration of $139.3 million and integrated these operations into our organization beginning August 2007.
- Maintained our monthly distributions of $0.38 per trust unit through the quarter representing approximately 87% of cash from operating activities.

SELECTED INFORMATION

The table below provides a summary of our financial and operating results for the three and nine month periods ended September 30, 2007 and 2006.

	Three Months Ended September 30			Nine Months Ended September 30		
($000s except where noted)	**2007**	2006	Change	**2007**	2006	Change
Revenue, net[1]	**1,007,786**	312,864	222%	**3,156,518**	677,424	366%
Cash From Operating Activities	**191,049**	143,597	33%	**553,315**	367,342	51%
Per trust unit, basic	**$ 1.31**	$ 1.35	(3%)	**$ 4.09**	$ 3.79	8%
Per trust unit, diluted	**$ 1.22**	$ 1.31	(7%)	**$ 3.74**	$ 3.67	2%
Net Income[2]	**11,811**	107,768	(89%)	**87,909**	134,513	(35%)
Per trust unit, basic	**$ 0.08**	$ 1.01	(92%)	**$ 0.65**	$ 1.39	(53%)
Per trust unit, diluted	**$ 0.08**	$ 0.99	(91%)	**$ 0.65**	$ 1.38	(53%)
Distributions declared	**166,271**	123,112	35%	**465,598**	333,813	39%
Distributions declared, per trust unit	**$ 1.14**	$ 1.14	-%	**$ 3.42**	$ 3.39	1%
Distributions declared as a percentage of Cash From Operating Activities	**87%**	86%	1%	**84%**	91%	(7%)
Bank debt				**1,205,119**	591,189	104%
Senior debt				**241,628**	279,425	(14%)
Convertible debentures[3]				**650,440**	235,114	177%
Total long-term financial liabilities[3]				**2,097,187**	1,105,728	90%
Total assets				**5,585,651**	4,076,771	37%
UPSTREAM OPERATIONS						
Daily Production						
Light to medium oil (bbl/d)	**27,401**	28,394	(3%)	**27,342**	27,136	1%
Heavy oil (bbl/d)	**14,217**	13,919	2%	**14,845**	14,003	6%
Natural gas liquids (bbl/d)	**2,219**	2,595	(14%)	**2,350**	2,111	11%
Natural gas (mcf/d)	**96,737**	103,618	(7%)	**98,682**	91,379	8%
Total daily sales volumes (boe/d)	**59,961**	62,178	(4%)	**60,984**	58,480	4%
Cash capital expenditures	**73,323**	129,054	(43%)	**270,031**	286,523	(6%)
DOWNSTREAM OPERATIONS						
Average daily throughput (bbl/d)	**103,983**	-	n/a	**111,052**	-	n/a
Aggregate throughput (mbbl)	**9,566**	-	n/a	**30,317**	-	n/a
Average Refining Margin (US$/bbl)	**3.08**	-	n/a	**10.57**	-	n/a
Cash capital expenditures	**12,468**	-	n/a	**27,222**	-	n/a

(1) Revenues are net of royalties and risk management activities
(2) Net Income includes a future income tax recovery of $54.4 million for the three months ended September 30, 2007 and a future tax expense of $123.3 million for the nine months ended September 30, 2007. Please see Note 14 to the Consolidated Financial Statements for further information.
(3) Includes current portion of Convertible Debentures.

REVIEW OF THIRD QUARTER PERFORMANCE

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

In the Third Quarter of 2007, we generated cash from operating activities of $191.0 million ($1.31 per basic trust unit) compared to $143.6 million ($1.35 per basic trust unit) in the Third Quarter of the prior year and $251.2 million in the Second Quarter of 2007. The $60.2 million reduction in the Third Quarter of 2007 as compared to the Second Quarter is primarily the result of a $161.8 million reduction in cash from our downstream operations offset by a $48.7 million reduction in non-cash working capital requirements, a $42.8 million increase in realized currency exchange gains and a $7.0 million increase in cash from our upstream operations. The $47.4 million increase over the prior year is primarily the result of a $58.8 million reduction in non-cash working capital requirements in the current year coupled with a $22.2 million reduction in cash settlements of commodity price risk management contracts and a $44.9 million increase in realized currency exchange gains in 2007. These increases are substantially offset by a $35.7 million reduction in cash from our upstream operations before commodity price risk management settlements, an $18.3 million increase in interest costs and the consumption of $23.4 million of cash by our downstream operations in the Third Quarter of 2007.

Cash from our upstream operations totaled $147.9 million during the third quarter of 2007 compared to $161.4 million reported in the prior year and $140.9 million in the Second Quarter of 2007. Relative to the prior year, our upstream operations reflect a 5% decline in revenues totaling $15.5 million as a result of a 3% decline in volume and a 2% decline in realized prices, a $23.8 million improvement in the cash settlements of our commodity price risk management contracts (excluding electricity contracts), and a $19.2 million increase in operating costs representing an increase in unit operating costs from $10.17 to $14.03 per boe as well as a $0.3 million increase in cash expenditures on general and administrative costs. These variances are explained by the combined impact of the Viking, Birchill and Grand acquisitions and year-over-year cost pressures. Relative to the Second Quarter of 2007, our upstream operations have benefited from a $12.1 million increase in revenues as a result of a 5% increase in average prices (higher oil prices offset by lower gas prices) offset by a 1% volume reduction, while a $1.7 million improvement in the cash settlements of our commodity price risk management contracts offsets an increase of $4.5 million in operating costs from $13.13 to $14.03 per boe. These variances are explained by relatively stable production, higher commodity prices and the impact of turnaround costs at third party processing facilities.

Our downstream operations consumed $23.4 million of cash during the Third Quarter which compares to $94.7 million and $138.4 million generated in the First and Second Quarters of 2007, respectively. The Third Quarter performance is primarily the result of the erosion of North Atlantic's refining margins from US$11.85 and US$15.64 per barrel of throughput realized in the First and Second Quarters, respectively, to US$3.08 per barrel in the Third Quarter. When coupled with a throughput reduction of approximately 10,650 bbls/d in the Third Quarter as compared to the average for the first six months of 2007, the drop in refining margins has resulted in a decrease in our Third Quarter gross margin of $109.1 million and $149.1 million as compared to the First Quarter and Second Quarter of 2007, respectively. In addition to declining margins, the Third Quarter also includes $6.6 million of costs related to the replacement of catalyst and a maintenance turnaround of the Isomax unit that commenced on September 21, 2007 and is the primary cause of the reduction in Third Quarter throughput.

The continued strength of the Canadian dollar throughout the Second and Third Quarters of 2007 had a significant impact on both our upstream and downstream revenues as their underlying prices are market driven in US dollars. The quarterly average Canadian / US dollar currency exchange rate has trended from US$0.854 in the First Quarter to US$0.911 in the Second Quarter to US$0.957 in the Third Quarter, reaching parity early in the Fourth Quarter. To mitigate the impact of fluctuations in the currency exchange rate, we have entered into fixed rate forward sales contracts and have maintained US dollar denominated debt; US$492.7 million of bank debt and US$250 million of 77/8% Senior Notes. During the Third Quarter, we crystallized a $43.5 million currency exchange gain with the conversion of the US$492.7 million of bank debt to Canadian dollar borrowings in addition to realizing $2.1 million on the monthly settlement of our forward sale of US$8.8 million at a fixed exchange rate of US$0.89.

On June 8, 2007, Harvest and Grand entered into an acquisition agreement whereby Harvest agreed to offer to purchase all of the outstanding shares of Grand for $3.84 per share in cash subject to there being at least 662/3% of the outstanding shares tendered to the offer. During the three months ended March 31, 2007, Grand's production averaged 3,409 boe/d composed of 2,322 barrels of oil and 6,521 mcf of natural gas with estimated total proved plus probable (P+P) reserves of 6 million boe. On July 26, 2007, we acquired approximately 74.6% of the outstanding shares of Grand and extended our offer to August 9, 2007, when we acquired an additional 20.0% of the Grand shares and proceeded to acquire the residual outstanding shares pursuant to the compulsory acquisition provisions of the Business Corporations Act (Alberta). In aggregate, the acquisition cost of Grand totaled $139.3 million: $109.7 million to acquire the shares of Grand, $28.8 million to repay Grand's bank debt and $0.8 million in respect of related acquisition costs. Subsequent to July 27, 2007, we swiftly integrated the operations of Grand into our organization and have been successful in limiting transition costs. The Grand assets are producing as expected, contributing approximately 3,354 boe/d through August and September while the three wells drilled just prior to the acquisition have resulted in three gas wells that will be tied in during the Fourth Quarter.

Distributions declared during the Third Quarter of 2007 totaled $1.14 per trust unit aggregating to $166.3 million representing 87% of cash from operating activities with the distributions declared year-to-date aggregating to $465.6 million and representing 84% of cash from operating activities. These ratios are not consistent with the "payout ratios" disclosed in previous quarters as the cash from operating activities has been adjusted for asset retirement expenditures as well as changes in non-cash working capital. During the Third Quarter of 2007, the participation in our distribution reinvestment plan was approximately 29%, while in the prior year the participation rate was approximately 37%. For Unitholders that so choose, we are able to settle their respective distributions with the issuance of trust units which resulted in distributions paid in cash of $117.5 million for the Third Quarter and $320.9 million year-to-date for 2007.

Business Segments

Following our acquisition of North Atlantic in October of 2006, our business has two segments: the upstream operations in western Canada and the downstream operations in the Province of Newfoundland and Labrador. Our upstream business consists of petroleum and natural gas production and development activities and our downstream business consists of a medium gravity sour crude hydrocracking refinery with a crude oil throughput capacity of 115,000 bbl/d, 61 retail gas stations, 3 cardlock locations as well as wholesale gasoline and home heating businesses. The following table presents selected financial information for our two business segments:

	Three Months Ended September 30				**Nine Months Ended September 30**			
		2007		2006		**2007**		2006
(in $000's)	**Upstream**	**Downstream**	**Total**	Total[3]	**Upstream**	**Downstream**	**Total**	Total[3]
Revenue[1]	222,643	785,143	1,007,787	312,864	690,107	2,466,411	3,156,518	677,424
Earnings (Losses) From Operations[2]	21,767	(44,079)	(22,313)	124,117	86,401	147,291	233,692	163,402
Capital expenditures	73,323	12,468	85,791	129,054	270,031	27,222	297,253	286,523
Total assets	4,085,987	1,499,663	5,585,651	4,076,771	4,085,987	1,499,663	5,585,651	4,076,771

(1) Revenues are net of royalties and risk management activities.
(2) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.
(3) For the three and nine month periods ended September 30, 2006, Harvest's operations consisted of only upstream operations.

UPSTREAM OPERATIONS

Financial and Operating Results

Throughout the Third Quarter of 2007, our production mix was approximately 50% light to medium oil and natural gas liquids, 24% heavy oil and 26% natural gas with our core areas of production located in Alberta, Saskatchewan and northeastern British Columbia.

The following summarizes the financial and operating information of our upstream operations for the three and nine month periods ended September 30, 2007 and 2006:

	Three Months Ended September 30			Nine Months Ended September 30		
(in $000's)	**2007**	2006	Change	**2007**	2006	Change
Revenues	$ **298,708**	$ 314,180	(5%)	$ **876,435**	$ 847,465	3%
Royalties	**(56,806)**	(54,362)	4%	**(160,003)**	(149,384)	7%
Realized losses on price risk management contracts[1]	**(4,596)**	(28,361)	(84%)	**(11,659)**	(61,687)	(81%)
Unrealized gains (losses) on price risk management contracts	**(17,466)**	77,078	(123%)	**(17,409)**	35,966	(148%)
Net revenues excluding realized losses on electric power fixed price contracts	**219,840**	308,535	(29%)	**687,364**	672,360	2%
Operating expenses	**80,189**	62,489	28%	**224,818**	173,176	30%
Realized gains on electric power fixed price contracts	**(2,803)**	(4,329)	(35%)	**(2,743)**	(5,064)	(46%)
Net operating expenses	**77,386**	58,160	33%	**222,075**	168,112	32%
General and administrative	**4,159**	7,500	(45%)	**30,324**	21,825	39%
Transportation and marketing	**3,413**	3,535	(3%)	**9,599**	9,223	4%
Transaction costs	**-**	-	n/a	**-**	12,072	n/a
Depreciation, depletion, amortization and accretion	**113,116**	115,223	(2%)	**338,965**	297,726	14%
Earnings From Operations[2]	**21,766**	124,117	(82%)	**86,401**	163,402	(47%)
Cash capital expenditures (excluding acquisitions)	**73,323**	129,054	(43%)	**270,031**	286,523	(6%)
Property and business acquisitions, net of dispositions	**139,378**	452,581	(69%)	**148,530**	476,253	(69%)
Daily sales volumes						
Light to medium oil (bbl/d)	**27,401**	28,394	(3%)	**27,342**	27,136	1%
Heavy oil (bbl/d)	**14,217**	13,919	2%	**14,845**	14,003	6%
Natural gas liquids (bbl/d)	**2,219**	2,595	(14%)	**2,350**	2,111	11%
Natural gas (mcf/d)	**96,737**	103,618	(7%)	**98,682**	91,379	8%
Total (boe/d)	**59,961**	62,178	(4%)	**60,984**	58,480	4%

(1) Includes amounts realized on WTI, natural gas and currency exchange contracts and excludes amounts realized on electric power fixed price contracts.
(2) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

Commodity Price Environment

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
Benchmarks	**2007**	2006	Change	**2007**	2006	Change
West Texas Intermediate crude oil (US$ per barrel)	**75.38**	70.58	7%	**66.19**	68.25	(3%)
Edmonton light crude oil ($ per barrel)	**79.66**	79.07	1%	**72.89**	75.55	(4%)
Bow River blend crude oil ($ per barrel)	**55.79**	58.65	(5%)	**52.20**	53.07	(2%)
AECO natural gas daily ($ per mcf)	**5.18**	5.64	(8%)	**6.55**	6.40	2%
AECO natural gas monthly ($ per mcf)	**5.61**	6.03	(7%)	**6.81**	7.19	(5%)
Canadian / U.S. dollar exchange rate	**0.957**	0.891	7%	**0.907**	0.883	3%

The West Texas Intermediate ("WTI") crude oil price was 7% higher and 3% lower than the prior year during the three and nine month periods ended September 30, 2007, respectively. In the Third Quarter of 2007, the average Edmonton light crude oil price ("Edmonton Par") was substantially unchanged as compared to the Third Quarter of 2006, as the relative strength of the Canadian dollar during the period offset the 7% increase in the WTI price. During the nine month period ended September 30, 2007, Edmonton Par decreased by 4% relative to the prior year while WTI decreased only 3%, also a result of a strengthened Canadian dollar which has increased 3% compared to the same nine month period in the prior year. The narrowing of the differentials between WTI and Edmonton Par in 2007 has continued with the strong demand for Canadian light crude resulting in an average premium of $0.89/bbl realized for Edmonton Par in the three month period ended September 30, 2007 as compared to a $0.14/bbl discount in the prior year.

In the Third Quarter of 2007, prices for heavy crude oil decreased by 5% from the prior year, a reflection of a widened heavy oil differential. For the nine month period ended September 30, 2007, the heavy oil differential has narrowed, resulting in a 2% reduction in the heavy oil price while Edmonton Par has decreased by 4% compared 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. In the Third Quarter of 2007, heavy oil demand was impacted by planned maintenance and unplanned disruptions of heavy oil refining in the United States coupled with production from new oil sands projects. Heavy oil differentials for the last eight quarters are shown below.

	2007			2006				2005
Differential Benchmarks	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Bow River Blend differential to Edmonton Par	**30.0%**	**29.4%**	**25.4%**	30.3%	25.8%	22.9%	42.0%	40.0%

Third Quarter natural gas prices were 8% lower than the prior year due to extremely high North American natural gas storage inventories in 2007.

Realized Commodity Prices

The following table provides our average price realized by product as well as our average realized price before and after realized losses on price risk management contracts for the three and nine month periods ended September 30, 2007 and 2006.

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
	2007	2006	Change	**2007**	2006	Change
Light to medium oil ($/bbl)	**68.10**	66.64	2%	**62.02**	62.13	-%
Heavy oil ($/bbl)	**48.95**	55.09	(11%)	**45.70**	48.61	(6%)
Natural gas liquids ($/bbl)	**61.63**	61.57	-%	**57.55**	60.81	(5%)
Natural gas ($/mcf)	**5.67**	5.75	(1%)	**7.10**	6.67	6%
Average realized price ($/boe)	**54.15**	54.92	(1%)	**52.64**	53.08	(1%)
Realized price risk management losses ($/boe)[1]	**(0.83)**	(4.96)	(83%)	**(0.70)**	(3.86)	(82%)
Net realized price ($/boe)	**53.32**	49.96	7%	**51.94**	49.22	6%

[1] Includes amounts realized on WTI, natural gas and foreign exchange contracts and excludes amounts realized on electric power fixed price contracts.

During the Third Quarter and for the year to date 2007, the average realized price we received for our production remained relatively unchanged from the prior year. However, we experienced significantly reduced losses on our price risk management contracts as we had higher floor prices than in our contracts that settled during the first nine months of 2006. As a result, we have net realized prices that are 7% and 6% higher during the three and nine months ended September 30, 2007, respectively, than the comparative periods in 2006.

The realized price of our light to medium oil sales increased 2% during the Third Quarter 2007 compared to the same period in the prior year, while the year-to-date price for 2007 was relatively unchanged. In the same comparative periods, Edmonton Par increased 1% and decreased 4%, respectively. While the Third Quarter price increases are as expected, the relative stability of the year-to-date price reflects the improved quality differentials realized in the First Quarter of 2007 for our light to medium oil production relative to the Edmonton Par benchmark price.

Third Quarter 2007 heavy oil production realized prices were 11% lower than in the prior year. This decrease reflects a 5% reduction in the Bow River price, which the majority of our heavy oil sales are price off of, coupled with the relatively heavier gravity of our recent heavy oil acquisitions in December 2006 and March 2007, which recieves a lower price at the wellhead. On a year-to-date basis, the realized price for our heavy oil production was 6% lower than for the first nine months in the prior year as compared to a 2% year-over-year reduction in the Bow River benchmark price for much the same reasons.

During the Third Quarter of 2007, the realized price for our natural gas production was 1% lower than in the prior year as compared to an 8% average decrease in the benchmark AECO daily prices; for the year-to-date prices, our realized price is 6% higher than in the prior year as compared to a 2% average increase in the benchmark AECO price for daily pricing. Typically, we sell approximately 60% of our natural gas sales priced off the AECO daily benchmark, approximately 30% sold off the AECO monthly benchmark with the remainder sold to aggregators. In the current year, we have consolidated our gas marketing arrangements with one third party marketer, which has resulted in overall higher realized prices for our natural gas production. Additionally, the natural gas produced in our larger natural gas producing properties generally has a higher than average heat content, which realizes a premium in its pricing.

Sales Volumes

The average daily sales volumes by product were as follows:

	Three Months Ended September 30				
	2007		2006		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)(1)	**27,401**	**46%**	28,394	46%	(3%)
Heavy oil (bbl/d)	**14,217**	**24%**	13,919	22%	2%
Total oil (bbl/d)	**41,618**	**70%**	42,313	68%	(2%)
Natural gas liquids (bbl/d)	**2,219**	**4%**	2,595	4%	(14%)
Total liquids (bbl/d)	**43,837**	**74%**	44,908	72%	(2%)
Natural gas (mcf/d)	**96,737**	**26%**	103,618	28%	(7%)
Total oil equivalent (boe/d)	**59,961**	**100%**	62,178	100%	(4%)

	Nine Months Ended September 30				
	2007		2006		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)(1)	**27,342**	**45%**	27,136	46%	1%
Heavy oil (bbl/d)	**14,845**	**24%**	14,003	24%	6%
Total oil (bbl/d)	**42,187**	**69%**	41,139	70%	3%
Natural gas liquids (bbl/d)	**2,350**	**4%**	2,111	4%	11%
Total liquids (bbl/d)	**44,537**	**73%**	43,250	74%	3%
Natural gas (mcf/d)	**98,682**	**27%**	91,379	26%	8%
Total oil equivalent (boe/d)	**60,984**	**100%**	58,480	100%	4%

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

For the three month period ended September 30, 2007, average production was 4% lower than in the prior year as reduced volumes of light to medium oil and natural gas more than offset the 2% increase in heavy oil. For the nine month period ending September 30, 2007, average production was 4% higher than the same period in the prior year, a result of increased heavy oil and natural gas volumes from recent acquisitions offset by unchanged light to medium oil volumes.

Light to medium oil production in the Third Quarter of 2007 has decreased 993 bbl/d (or 3%) as compared to the same period in the prior year primarily due to declines off the winter capital program in Hay River of approximately 1,750 bbl/d coupled with production disruptions in other areas associated with wet weather, power failures and normal declines. Offsetting these disruptions was the acquisition of Grand in August (which added an incremental 1,100 bbl/d of light to medium oil production in the quarter), additional production from new wells coming online during the quarter and increased production resulting from workover activity undertaken in the Second Quarter. Year-to-date, our light to medium oil production is relatively unchanged as the incremental production increases associated with the acquisitions completed during 2006 and 2007 have been offset by normal declines and various operational issues causing down time in some of our major areas.

During the Third Quarter of 2007, our heavy oil production increased 298 bbl/d (or 2%) over the Third Quarter of 2006. Acquisitions completed in December 2006 and late February 2007 have added approximately 3,000 bbl/d of incremental heavy oil production which has more than offset the normal declines in other areas. Additionally, new wells have increased production at Lloydminster and Suffield despite down time due to well servicing and "military lockouts" at Suffield during the Third Quarter where our operations are located on a Canadian Forces Base. For the nine months ended September 30, 2007, heavy oil production has increased 842 bbl/d or 6% over the prior year, primarily due to the heavy oil acquisitions that have been completed in late 2006 and early 2007.

Third Quarter natural gas production has decreased 6,881 mcf/d (or 7%) compared to the prior year, a result of continued disruptions from third party processing facility turnarounds, specifically in our Crossfield area where production volumes were reduced by 4,600 mcf/d, coupled with higher than anticipated production declines from properties acquired with the acquisition of Birchill in August 2006. Year-to-date natural gas production has increased by 7,303 mcf/d or 8%, a result of the inclusion of nine months of the Viking and Birchill acquisitions in 2007 compared with only eight months of Viking production and two months of Birchill production included in 2006. For the balance of 2007, our natural gas focus will be limited to achieving better than average production from existing assets and expediting the tie-in of wells drilled in late 2006 and through 2007.

Revenues

	Three Months Ended September 30		
(000s)	**2007**	2006	Change
Light to medium oil sales	**$ 171,674**	$ 174,083	(1%)
Heavy oil sales	**64,026**	70,541	(9%)
Natural gas sales	**50,424**	54,855	(8%)
Natural gas liquids sales and other	**12,584**	14,701	(14%)
Total sales revenue	**298,708**	314,180	(5%)
Realized risk management contract losses[1]	**(4,596)**	(28,361)	(84%)
Total revenues including realized risk management contract losses	**294,112**	285,819	3%
Realized gains on electric power price risk management contracts	**2,803**	4,329	(35%)
Unrealized gains / (losses) on price risk management contracts	**(17,466)**	77,078	(123%)
Net Revenues, before royalties	**279,449**	367,226	(24%)
Royalties	**(56,806)**	(54,362)	4%
Net Revenues	**$ 222,643**	$ 312,864	(29%)

	Nine Months Ended September 30		
(000s)	**2007**	2006	Change
Light to medium oil sales	**$ 462,964**	$ 460,249	1%
Heavy oil sales	**185,196**	185,828	-%
Natural gas sales	**191,357**	166,344	15%
Natural gas liquids sales and other	**36,918**	35,044	5%
Total sales revenue	**876,435**	847,465	3%
Realized risk management contract losses[(1)]	**(11,659)**	(61,687)	(81%)
Total revenues including realized risk management contract losses	**864,776**	785,778	10%
Realized gains on electric power price risk management contracts	**2,743**	5,064	(46%)
Unrealized gains (losses) on price risk management contracts	**(17,409)**	35,966	(148%)
Net Revenues, before royalties	**850,110**	826,808	3%
Royalties	**(160,003)**	(149,384)	7%
Net Revenues	**$ 690,107**	$ 677,424	2%

(1) Includes amounts realized on WTI, natural gas and currency exchange contracts, and excludes amounts realized on electricity contracts.

Our revenue is impacted by changes to production volumes, commodity prices, and currency exchange rates. During the Third Quarter of 2007, total sales revenue of $298.7 million was $15.5 million lower than in the prior year, of which $10.3 million is attributed to lower production volumes and $5.2 million in attributed to lower realized prices. Year-to-date, total sales revenues were $876.4 million, an increase of $29.0 million over the prior year with $31.9 million attributed to increased volume primarily due to the acquisition of Birchill in August of 2006 and the acquisition of Viking in February 2006, offset by $2.9 million as a result of lower realized prices.

Light to medium oil sales revenue for the three month period ended September 30, 2007 was $2.4 million lower than in the comparative period, due to a $6.1 million unfavourable volume variance offset by a $3.7 million favourable price variance. The unfavourable volume variance in 2007 is primarily a result of the higher than expected declines off of the winter capital program in Hay River and delayed well servicing activity as a result of wet weather. Increased demand for Canadian light sweet crude oil has resulted in increased realized prices on our light to medium oil production and has had a positive impact on overall revenue. The year-to-date light to medium oil sales revenues have increased over the prior year by $2.7 million with the impact of incremental volumes from the acquisitions of Birchill and Viking in 2006 and of Grand in the Third Quarter of 2007 while realized prices remained unchanged.

During the Third Quarter of 2007, our heavy oil sales revenue of $64.0 million was $6.5 million lower than in the prior year due to an $8.0 million unfavourable price variance resulting from a shift in our heavy oil production to a heavier gravity crude and a $1.5 million favourable volume variance resulting from the recent acquisitions of heavy oil properties and the incremental production from recent drilling. Year-to-date, our heavy oil revenues are substantially unchanged from the nine months ended September 30, 2006 as an $11.2 million favourable volume variance (again due to recent acquisitions and incremental drilling activity) is offset by an $11.8 million unfavourable reduction in the realized price.

Natural gas sales revenue decreased by $4.4 million during the three months ended September 30, 2007 compared to the prior year due to a $3.6 million unfavourable volume variance coupled with a modest $800,000 unfavourable price variance. Year-to-date, natural gas sales revenues are $25.0 million higher than in the first nine months of 2006 with a $0.43 per mcf price increase resulting in an $11.7 million favourable variance coupled with a $13.3 million favourable volume variance, primarily attributed to the incremental natural gas production from the acquisition of Birchill in August of 2006 and Viking in February of 2006.

During the Third Quarter of 2007, our natural gas liquids and other sales revenue decreased by $2.1 million compared to the prior year while year-to-date, our revenues increased by $1.9 million. During the Third Quarter of 2007, the decreased revenue is attributed to a $2.1 million unfavourable volume variance with substantially unchanged prices while year-to-date revenues have increased due to a $4.0 million favourable volume variance offset somewhat by a $2.1 million unfavourable price 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.

Price Risk Management

Subsequent to acquiring North Atlantic, Harvest's participation in the crude oil value chain was extended to include the sale of refined products produced by North Atlantic, principally gasoline, distillates (which encompasses low sulphur diesel fuel, jet fuel and heating oil) and heavy fuel oil. This results in our price protection of future cash flows including refining margins/crack spreads on refined products. For purposes of this MD&A and the segmented reporting in Note 17 of our financial statements, our price risk management contracts are presented as either relating to our upstream operations or our downstream operations according to the price exposure that is being managed. Commencing in the Second Quarter of 2007, we have entered into refined product price contracts with third party counterparts and concurrently entered into inter-company contracts between our upstream and downstream operations to shift the WTI price protection to our upstream operations thereby leaving the refining margin/crack spread protection with the downstream operations.

In the Second Quarter of 2007, North Atlantic entered into price risk management contracts with respect to an aggregate of 20,000 bbl/d of NYMEX heating oil and Platts fuel oil for the period from January 2008 through December 2008, and in the Third Quarter of 2007 entered into contracts for an additional 10,000 bbl/d of NYMEX heating oil and Platts fuel oil for the period from January 2009 through June 2009. Subsequent to the end of the Third Quarter, North Atlantic has entered into additional contracts in respect of 10,000 bbl/d of NYMEX heating oil and Platts fuel oil for the period from January 2009 through June 2009. Concurrent with entering into these contracts, North Atlantic and Harvest entered into the following inter-company contracts to shift the WTI price protection to our upstream operations:

Quantity	Term	Contracted Price
4,000 bbls/d	Jan 2008 – Dec 2008	Price Floor – US$66.00 and Price Cap – US$75.79
16,000 bbls/d	Jan 2008 – Dec 2008	If WTI price is over US$79.57, price received is US$79.57
		If WTI price is between US$79.57 and $67.03, price received is market price
		If WTI price is between US$67.03 and US$52.33, price received is US$67.03
		If WTI price is under US$52.33, price received is market price plus US$14.70
10,000 bbls/d	Jan 2009 – Jun 2009	If WTI price is over US$83.32, price received is US$83.32
		If WTI price is between US$83.32 and US$70.42, price received is market price
		If WTI price is between US$70.42 and US$59.39, price received is US$70.42
		If WTI price is under US$59.39, price received is market price plus US$11.03
10,000 bbls/d	Jan 2009 – Jun 2009	If WTI price is over US$86.86, price received is US$86.86
		If WTI price is between US$86.86 and US$75.27, price received is market price
		If WTI price is between US$75.27 and US$64.48, price received is US$75.27
		If WTI price is under US$64.48, price received is market price plus US$10.79

In addition to these inter-company contracts, we have WTI price risk management contracts with third parties for 10,000 bbls/d for the period January 2008 through June 2008 that provide an average floor price of US$60.00 with an average upside participation of 73% above the floor price. Subsequent to the end of the Third Quarter, we entered into three-way WTI price risk management contracts with third parties in respect of 6,000 bbl/d for the period July 2008 through December 2008 with the following pricing:

- If WTI price is over US $87.50, price received is US $87.50
- If WTI price is between US $87.50 and US $72.00, price received is market price
- If WTI price is between US $72.00 and US $62.00, price received is US $72.00
- If WTI price is under US $62.00, price received is market price plus US $10.00

In aggregate and including the inter-company contracts, we have price risk management contracts in place on approximately 93% of our anticipated net oil production for the first six months of 2008, 80% for the last six months of 2008 and 62% the first six months of 2009.

With respect to the Fourth Quarter of 2007, we have WTI price risk management contracts for 20,000 bbls/d that provide an average floor price of US$58.75 with an average upside participation of 72% above the floor price and a further 5,000 bbls/d contracted using an indexed put contract at a floor price of US$50.00. These contracts cover approximately 71% of our anticipated net oil production during the Fourth Quarter.

Details of our price risk management contracts outstanding at September 30, 2007 are included in Note 16 of our interim consolidated financial statements for the three and nine month periods ended September 30, 2007 filed on SEDAR at www.sedar.com.

The table below provides a summary of net gains and losses on our price risk management contracts for both the three and nine month periods ended September 30, 2007 and 2006:

	Three Months Ended September 30					
	2007					2006
(000s)	Oil	Gas	Currency	Electricity	Total	Total
Realized (losses) / gains on price risk management contracts	$ (12,922)	$ 6,275	$ 2,051	$ 2,803	$ (1,793)	$ (24,032)
Unrealized (losses) / gains on price risk management contracts	(2,836)	(5,183)	6,600	(4,819)	(6,238)	77,046
Amortization of deferred gains relating to risk management contracts	-	-	-	-	-	32
Total (losses) / gains on third party risk management contracts	$ (15,758)	$ 1,092	$ 8,651	$ (2,016)	$ (8,031)	$ 53,046
Unrealized losses on WTI portion of refined product price risk management contracts	(11,228)	-	-	-	(11,228)	-
Total (losses) / gains on price risk management contracts	$ (26,986)	$ 1,092	$ 8,651	$ (2,016)	$ (19,259)	$ 53,046

	Nine Months Ended September 30					
	2007					2006
(000s)	Oil	Gas	Currency	Electricity	Total	Total
Realized (losses) / gains on price risk management contracts	$ (19,675)	$ 6,566	$ 1,450	$ 2,743	$ (8,916)	$ (56,623)
Unrealized (losses) / gains on price risk management contracts	(14,205)	(644)	17,666	(3,511)	(694)	35,601
Amortization of deferred gains relating to risk management contracts	-	-	-	-	-	365
Total (losses) / gains on third party risk management contracts	$ (33,880)	$ 5,922	$ 19,116	$ (768)	$ (9,610)	$ (20,657)
Unrealized losses on WTI portion of refined product price risk management contracts	(16,715)	-	-	-	(16,715)	-
Total (losses) / gains on price risk management contracts	$ (50,595)	$ 5,922	$ 19,116	$ (768)	$ (26,325)	$ (20,657)

During the three months ended September 30, 2007, our realized net loss on commodity price risk management contracts related to our upstream operations was $1.8 million as compared to a loss of $24.0 million in the Third Quarter of 2006. Year-to-date, our upstream price risk management program has realized a net loss of $8.9 million as compared to losses of $56.6 million during the first nine months of 2006. The principal difference between 2007 and 2006 is the significant reduction in the losses on crude oil price contracts as the floor price on these participating contracts has increased from an average of US$45.44 in 2006 to an average of approximately US$57.00 in 2007. Additionally, we unwound a natural gas price risk management contract in the Third Quarter of 2007, resulting in a $5.5 million realized gain. In both 2007 and the prior year, the results of our currency exchange rate and electricity price contracts did not result in either a material gain or material loss.

For the three months ended September 30, 2007, our oil price contracts realized losses of $12.9 million as compared to $7.0 million during the Second Quarter of 2007 and $30.0 million in the three months ended September 30, 2006. During the Third Quarter of 2007, we had WTI price risk management contracts on 25,000 bbl/d with downside protection at an average floor price of approximately US$57.00 per bbl including 72% participation on prices over US$58.75 on 20,000 bbl/d as compared to 23,750 bbl/d contracted with downside protection at an average floor price of US$45.44 and 59% participation in prices above US$42.93 in the prior year. The WTI price during the Third Quarter of 2007 averaged US$75.38, an increase of US$4.80

from US$70.58 in the prior year. The reduction of our losses on oil price risk management contracts in 2007 is the result of the higher contracted floor prices partially offset by higher WTI prices.

During the Third Quarter of 2007, our inter-company WTI contracts have given rise to an $11.2 million unrealized loss for the upstream operations while providing an $11.2 million unrealized gain for our downstream operations.

During the Second Quarter of 2007, we had natural gas contracts in place to protect cash flows on our natural gas production for 30,000 GJ/d beginning April 2007. In July 2007, we unwound these contracts, realizing a gain of $5.5 million in the Third Quarter. Currently, we have natural gas price risk management contracts in place on 276 GJ/d extending out to December 2008.

During the first nine months of 2007, we had currency exchange rate contracts in place on US$8,750,000 per month at a fixed rate of approximately US$0.89 which resulted in a realized loss of $1.2 million in the First Quarter, a realized gain of $647,000 in the Second Quarter and a realized gain of $2.1 million in the Third Quarter for a cumulative net gain of $1.5 million year-to-date, as the exchange rate averaged approximately US$0.854 during the First Quarter, US$0.911 during the Second Quarter and US$0.957 in the Third Quarter. For the balance of 2007, we have contracts that fix the currency exchange rate on US$8,750,000 per month at an average rate of approximately US$0.89 as well as a collar contract on US$10,000,000 per month with a price floor of US$1.00 and a cap of US$0.95. In addition, our U.S. dollar denominated 77/8% Senior Notes and the related US dollar interest payments offset the impact of Canadian/U.S. currency exchange rate fluctuations on our US dollar denominated oil sales revenues. See the discussion of our Currency Exchange Gains and Losses in the Financing and Other section of this MD&A for a review of the impact of our U.S. dollar denominated debt.

During the Third Quarter of 2007, our electric power price risk management contracts realized a gain of $2.8 million as compared to a loss of $560,000 in the Second Quarter of 2007 and a gain of $4.3 million in the Third Quarter of the prior year. We enter into these contracts to provide protection from rising electric power prices. During the Third Quarter of 2007, Alberta's electric power price averaged $92.00 per megawatt hour ("MWh") as compared to our contracted price of $56.69 per MWh. Additional details on these contracts is provided under the heading "Operating Expenses" of this MD&A.

During the Third Quarter of 2007, we recorded a net unrealized loss on our upstream price risk management contracts of $17.5 million comprised of losses on our WTI price contracts (including $11.2 million in respect of the inter-company contracts with North Atlantic) of $14.1 million, losses on natural gas and electricity price contracts of $10.0 million offset by unrealized gains of $6.6 million on foreign exchange forward sales contracts. At September 30, 2007, our price risk management contracts, including the North Atlantic refined product contracts, had a net unrealized mark-to-market deficiency of $26.9 million as compared to a net mark-to-market deficiency of $1.9 million at December 31, 2006.

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 three and nine months ended September 30, 2007, our net royalties as a percentage of gross revenue were 19.0% (17.3% - three months ended September 30, 2006) and 18.3% (17.6% - nine months ended September 30, 2006) and aggregated to $56.8 million ($54.4 million – three months ended September 30, 2006) and $160.0 million ($149.4 million – nine months ended September 30, 2006), respectively. Our Third Quarter 2007 and year-to-date royalty rates are slightly higher than our expected rate of 18% as we have been assessed additional crown royalties by the provincial government of British Columbia on our Hay River properties, of which an additional $1.0 million was recorded in the Second Quarter and $2.0 million was recorded in the Third Quarter.

Operating Expenses

(000s except per boe amounts)	Three Months Ended September 30 2007	Per BOE	2006	Per BOE	Per BOE Change
Operating expense					
Power	$ 18,259	$ 3.31	$ 17,491	$ 3.06	8%
Workovers	16,121	2.92	13,203	2.31	26%
Repairs and maintenance	17,996	3.27	5,762	1.01	223%
Labour - internal	3,514	0.64	5,260	0.92	(30%)
Processing fees	5,995	1.09	4,991	0.87	25%
Fuel	1,610	0.29	1,710	0.30	(3%)
Labour - external	3,991	0.72	3,239	0.57	26%
Land leases and property tax	5,648	1.02	6,193	1.08	(6%)
Other	7,055	1.28	4,640	0.81	58%
Total operating expense	80,189	14.54	62,489	10.92	33%
Realized gains on electric power price risk management contracts	(2,803)	(0.51)	(4,329)	(0.76)	(33%)
Net operating expense	$ 77,386	$ 14.03	$ 58,160	$ 10.17	38%
Transportation and marketing expense	$ 3,413	$ 0.62	$ 3,535	$ 0.62	-%

(000s except per boe amounts)	Nine Months Ended September 30 2007	Per BOE	2006	Per BOE	Per BOE Change
Operating expense					
Power	$ 43,399	$ 2.61	$ 41,746	$ 2.61	-%
Workovers	48,139	2.89	35,392	2.22	30%
Repairs and maintenance	47,745	2.87	17,707	1.11	159%
Labour - internal	11,390	0.68	15,105	0.95	(28%)
Processing fees	22,549	1.35	14,094	0.88	53%
Fuel	6,249	0.38	6,121	0.38	-%
Labour - external	11,786	0.71	9,775	0.61	16%
Land leases and property tax	14,180	0.85	15,119	0.95	(11%)
Other	19,381	1.16	18,117	1.13	3%
Total operating expense	224,818	13.50	173,176	10.85	24%
Realized gains on electric power price risk management contracts	(2,743)	(0.16)	(5,064)	(0.32)	(50%)
Net operating expense	$ 222,075	$ 13.34	$ 168,112	$ 10.53	27%
Transportation and marketing expense	$ 9,599	$ 0.58	$ 9,223	$ 0.58	-%

Total operating expense increased by $17.7 million and $51.6 million respectively for the three and nine month periods ended September 30, 2007 compared to the same periods in the prior year. A significant portion of this increase is attributed to the incremental activity associated with the assets acquired in the Birchill acquisition completed in August 2006. Additionally, in the Third Quarter, a significant turnaround at a third-party processing plant in the Crossfield area accounted for a one-time $5.5 million increase in repairs and maintenance expense. The continued high demand for oilfield services has lead to higher costs for well servicing, workovers, labour and well maintenance, though we are beginning to see evidence of service costs decreasing which should translate to lower per unit operating costs in the coming quarters.

On a per barrel basis our operating costs have increased to $14.54 and $13.50 respectively for the three and nine month periods ended September 30, 2007, which represents a 33% and 24% increase over the same periods in the prior year. In addition to the general upward cost pressures in the industry, there was a significant amount of well maintenance and workovers completed in the first three quarters of 2007 as compared to the prior year. The increase in processing fees are directly related to our greater proportion of non-operated properties as a result of the acquisition of Birchill. Generally, we incur higher processing fees on non-operated properties as although we own an interest in the well, we may not own an interest in the processing plant and are usually charged a fee for processing which is higher than the per unit cost of operating the facility.

Our transportation and marketing expense was $3.4 million or $0.62 per boe and $9.6 million or $0.58 per boe respectively for the three and nine month periods ended September 30, 2007, which is substantially unchanged from the comparative periods in the prior year. 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 and the cost per boe is expected to remain relatively constant.

Electric power costs represented approximately 23% and 19% of our total operating costs during the three and nine month periods ended September 30, 2007. Electric power prices per MWh for the Third Quarter were 3% lower than the Third Quarter 2006 while year-to-date prices remained constant with the prior year. The 4% increase in aggregate power costs to $18.3 million in the current quarter and the 4% increase to $43.4 million for the year-to-date compared to 2006 is due to increased consumption as a result of the acquisitions of Birchill and to a lesser extent, Grand. On a per barrel basis, a higher level of consumption and a 4% decrease in production volumes resulted in an 8% increase in electric power costs for the three months ended September 30, 2007. Higher consumption and a 4% increase in production resulted in unit electric power costs remaining constant for the nine months ended September 30, 2007. Our electric power price risk management contracts resulted in gains of $2.8 million and $2.7 million for the three and nine month periods ended September 30, 2007, respectively, compared to gains of $4.3 million and $5.1 million in the same periods in 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 Sept. 30			Nine Months Ended Sept. 30		
(per boe)	**2007**	2006	Change	**2007**	2006	Change
Electric power costs	**$ 3.31**	$ 3.06	8%	**$ 2.61**	$ 2.61	-%
Realized gains on electricity risk management contracts	**(0.51)**	(0.76)	(33%)	**(0.16)**	(0.32)	(50%)
Net electric power costs	**$ 2.80**	$ 2.30	22%	**$ 2.45**	$ 2.29	7%
Alberta Power Pool electricity price (per MWh)	**$ 92.00**	$ 94.74	(3%)	**$ 68.53**	$ 68.36	-%

Approximately 52% of our estimated Alberta electricity usage is protected by fixed price purchase contracts at an average price of $56.69 per MWh through December 2008. These contracts will 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.

Operating Netback

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(per boe)	**2007**	2006	**2007**	2006
Revenues	**$ 54.15**	$ 54.92	**$ 52.64**	$ 53.08
Realized loss on risk management contracts(1)	**(0.83)**	(4.96)	**(0.70)**	(3.86)
Royalties	**(10.30)**	(9.50)	**(9.61)**	(9.36)
Operating expense(2)	**(14.03)**	(10.17)	**(13.34)**	(10.53)
Transportation and marketing expense	**(0.62)**	(0.62)	**(0.58)**	(0.58)
Operating netback(3)	**$ 28.37**	$ 29.67	**$ 28.41**	$ 28.75

(1) Includes amounts realized on WTI, natural gas and foreign exchange contracts, and excludes amounts realized on electricity contracts.
(2) Includes realized gains on electric power price risk management contracts of $0.51 per boe and $0.76 per boe for the three month periods ended September 30, 2007 and 2006 and $0.16 per boe and $0.32 per boe for the nine month periods ended September 30, 2007 and 2006.
(3) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

Our operating netback represents the net amount realized on a per boe basis after deducting the directly related costs. In the Third Quarter 2007, our operating netback decreased $1.30 per boe (or 4%) to $28.37 compared to the same period in the prior year and remained relatively unchanged on a year-to-date basis as compared to the first nine months of 2006. The decrease in the Third Quarter 2007 operating netback as compared to the prior year is due to increased operating expenses of $3.86 per boe and increased royalties of $0.80 per boe and marginally lower realized prices, offset by reduced realized price risk management contract losses of $4.13 per boe. The small decrease in the operating netback for the nine months ended September 30, 2007 is due primarily to increased operating costs of $2.81 per boe and decreased realized prices of $0.44 per boe offset by reduced realized losses on price risk management contracts of $3.16 per boe.

General and Administrative ("G&A") Expense

	Three Months Ended September 30			Nine Months Ended September 30		
(000s except per boe)	**2007**	2006	Change	**2007**	2006	Change
Cash G&A[(1)]	**$ 8,330**	$ 6,962	20%	**$ 24,048**	$ 20,771	16%
Unit based compensation expense (recovery)	**(4,171)**	538	(875%)	**6,276**	1,054	495%
Total G&A	**$ 4,159**	$ 7,500	(45%)	**$ 30,324**	$ 21,825	39%
Cash G&A per boe ($/boe)	**$ 1.51**	1.22	24%	**$ 1.44**	1.30	11%

(1) Cash G&A excludes the impact of our unit based compensation expense and for the three and nine months ended September 30, 2006 of nil and $2.1 million, respectively, of one time transaction costs.

For the three months ended September 30, 2007, Cash G&A costs increased by $1.4 million (or 20%) compared to the same period in 2006. This increase is mainly related to salaries, which is attributed largely to increased staffing levels from our acquisition of Birchill in August 2006, with a nominal increase associated with our recent acquisition of Grand. Approximately 75% of our Cash G&A expenses are related to salaries and other employee related costs, while in the prior year only 63% of our Cash G&A was staffing related. Generally, costs to retain technically qualified staff in the western Canadian petroleum and natural gas industry continue to rise.

Our unit based compensation plans provide the employee with the option of settling outstanding awards with cash. As a result, our 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 appreciation rights ("UAR") adjusted for the proportion that is vested. Our opening trust unit market price was $32.95 at June 30, 2007 and at September 30, 2007, our trust unit price had decreased to $26.77. Accordingly, in the Third Quarter of 2007, we recorded a recovery of $4.2 million in respect of our unit based compensation plans. Our total unit based compensation expense has decreased $4.7 million for the three month period ended September 30, 2007 and $3.8 million for the nine month period ended September 30, 2007 over the same periods in the prior year after considering that $9.0 million in the nine month period ended September 30, 2006 was recorded as transaction costs. In 2006, we have recorded transaction costs of $12.1 million which represent one time costs incurred by Harvest as part of the acquisition of Viking in respect of Harvest's outstanding UARs vesting on February 3, 2006 and severance payments made to Harvest employees upon merging with Viking.

Depletion, Depreciation, Amortization and Accretion Expense

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
(000s except per boe)	**2007**	2006	Change	**2007**	2006	Change
Depletion, depreciation and amortization	**$ 104,643**	$ 106,922	(2%)	**$ 313,573**	$ 273,203	15%
Depletion of capitalized asset retirement costs	**3,926**	4,219	(7%)	**11,926**	12,731	(6%)
Accretion on asset retirement obligation	**4,546**	4,082	11%	**13,466**	11,792	14%
Total depletion, depreciation, amortization and accretion	**$ 113,115**	$ 115,223	(2%)	**$ 338,965**	$ 297,726	14%
Per boe	**$ 20.51**	$ 20.14	2%	**$ 20.36**	$ 18.65	9%

Our overall depletion, depreciation, amortization and accretion ("DDA&A") expense for the three and nine months ended September 30, 2007 was $2.1 million lower and $41.2 million higher, respectively, compared to the prior year. The marginal decrease in the Third Quarter is primarily due to reduced production volumes, while the year-to-date increase reflects increased production volumes resulting from our acquisitions coupled with higher finding and development costs that have increased our overall DDA&A rate.

Capital Expenditures

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(000s)	**2007**	2006	**2007**	2006
Land and undeveloped lease rentals	**$ 645**	$ 4,552	**$ 1,066**	$ 6,965
Geological and geophysical	**1,340**	1,573	**7,064**	4,600
Drilling and completion	**38,619**	90,763	**133,608**	175,625
Well equipment, pipelines and facilities	**30,031**	29,370	**119,607**	85,650
Capitalized G&A expenses	**2,440**	2,796	**6,891**	9,777
Furniture, leaseholds and office equipment	**248**	-	**1,795**	3,906
Development capital expenditures excluding acquisitions and non-cash items	**73,323**	129,054	**270,031**	286,523
Non-cash capital additions (recoveries)	**(1,042)**	(236)	**(1,053)**	(409)
Total development capital expenditures excluding acquisitions	**$ 72,281**	$ 128,818	**$ 268,978**	$ 286,114

During the Third Quarter of 2007 Harvest invested $73.3 million in development capital expenditures compared to $129.1 million in the Third Quarter of 2006. Approximately 52% of these expenditures were used to drill 55 gross wells with a success rate of 100%, compared to 76 gross wells with a success rate of 97% in the same period in 2006. While we continued to focus our drilling activity on oil opportunities (74% of the total net wells drilled) given the strong oil price environment, our central Alberta gas drilling resulted in some particularly successful wells.

At Markerville, we drilled a follow-up to an Ellerslie gas discovery well and were able to confirm an extension to the discovered pool. Initial test data indicates that the well has a productive capacity of approximately 500 boe/d including liquids, of which Harvest has a 100% working interest. Similarly, an exploratory well in central Alberta encountered significant net gas pay, and initial test data indicates that this well has a productive capacity of approximately 800 boe/d including liquids, of which Harvest has a 100% working interest. Follow-up locations have been identified in both cases which we will be pursuing as part of our 2008 capital program.

In southeast Saskatchewan, we continue to successfully exploit our Souris Valley light oil pools with a total of 12 gross horizontal wells being drilled. Four of these wells were on lands acquired from Grand as we continue to pursue the opportunities on this significant land base. At Hayter, we drilled 7 infill horizontal wells into an older portion of the Dina oil reservoir that, until recently, had been deemed to be sufficiently developed. Reservoir analysis indicated incremental recovery could be achieved using our horizontal well technology, and additional infill locations have been identified for 2008. At Lloydminster, we continue to delineate the Lloyminster oil reservoir with horizontal wells, having drilled 7 gross wells in the quarter.

Our enhanced recovery projects continue to progress as we head towards implementation in 2008. At Bellshill Lake, we have confirmed that increased water injection into the Ellerslie Formation has the potential to add up to 16 mmboe of additional medium oil reserves. Infrastructure modifications will be undertaken in 2008 to initiate the first phase of this improved recovery project. At Wainwright, our technical evaluation of the polymer pilot has been completed, and we are in the process of sourcing necessary equipment, with expenditures and pilot start-up to occur in 2008. Technical studies have indicated pool wide recovery factors could exceed 50% of the original medium gravity oil in this large resource pool (135 mmboe original resource in place).

The $30.0 million of well equipment, pipelines and facilities expenditures incurred during the three months ended September 30, 2007 include $4.0 million relating to the expansion of our oil processing facilities at Red Earth. The expansion will allow for the optimization of Slave Point light oil production and will provide the necessary infrastructure to accommodate our 2008 drilling program.

The following summarizes Harvest's participation in gross and net wells drilled during the Third Quarter of 2007:

Area	Total Wells Gross[1]	Total Wells Net	Successful Wells Gross	Successful Wells Net	Abandoned Wells Gross	Abandoned Wells Net
Hay River	-	-	-	-	-	-
Southeast Saskatchewan	12.0	10.0	12.0	10.0	-	-
Red Earth	-	-	-	-	-	-
Suffield	2.0	2.0	2.0	2.0	-	-
Lloydminster	7.0	7.0	7.0	7.0	-	-
Markerville	7.0	3.7	7.0	3.7	-	-
Other Areas	27.0	12.5	27.0	12.5	-	-
Total	55.0	35.2	55.0	35.2	-	-

(1) Excludes 9 additional wells that we have an overriding royalty interest in.

The following summarizes Harvest's participation in gross and net wells drilled for the nine months ended September 30, 2007:

Area	Total Wells Gross[1]	Total Wells Net	Successful Wells Gross	Successful Wells Net	Abandoned Wells Gross	Abandoned Wells Net
Hay River	31.0	31.0	31.0	31.0	-	-
Southeast Saskatchewan	27.0	25.0	27.0	25.0	-	-
Red Earth	12.0	8.5	12.0	8.5	-	-
Suffield	10.0	10.0	9.0	9.0	1.0	1.0
Lloydminster	15.0	15.0	15.0	15.0	-	-
Markerville	12.0	5.6	12.0	5.6	-	-
Other Areas	54.0	26.5	52.0	25.9	2.0	0.6
Total	161.0	121.6	158.0	120.0	3.0	1.6

(1) Excludes 21 additional wells that we have an overriding royalty interest in.

Corporate Acquisitions

Effective March 1, 2007, we acquired a private petroleum and natural gas corporation for cash consideration of \$30.6 million including \$350,000 of estimated acquisition costs. This acquisition added approximately 1,500 bbl/d of western Saskatchewan heavy oil production which is adjacent to our existing operations in the area.

In early August 2007, we completed the acquisition of Grand for aggregate consideration of approximately \$139.3 million (including repayment of its \$28.8 million bank debt), acquiring approximately 3,400 boe/d of production with proved plus probable (P+P) reserves of 6 million boe, composed of approximately 67% oil. Grand's assets include a significant presence in southeast Saskatchewan, the Sylvan Lake/Markerville area and eastern Alberta which are adjacent to existing Harvest operations with complementary drilling opportunities. Grand also has 65,000 acres (46,000 net acres) of undeveloped land with supporting seismic data providing further development opportunities. This acquisition represents an acquisition cost of approximately \$41,000 per flowing boe and \$23.00 per boe of proved and probable reserves.

Goodwill

Goodwill is recorded when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of that acquired business. At December 31, 2006, we had recorded \$656.2 million of goodwill related to our upstream segment, and in the Third Quarter 2007, we have added an additional \$20.5 million of goodwill with our purchase of Grand. The goodwill balance is assessed annually for impairment or more frequently if events or changes in circumstances occur that would reasonably be expected to reduce the fair value of the acquired business to a level below its carrying amount. To date, no charge for impairment of this goodwill has been made.

Asset Retirement Obligation ("ARO")

In connection with a property acquisition or development expenditures, we record the fair value of the ARO as a liability in the same year as the expenditure occurs. Our ARO 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 $6.6 million during the three months ended September 30, 2007 and $14.2 million during the nine months ended September 30, 2007. These increases are due to additions resulting from corporate acquisitions, drilling activity during the quarter and accretion expense, offset by actual asset retirement expenditures made during the period.

DOWNSTREAM OPERATIONS

Our downstream operations, operating under the North Atlantic trade name, are comprised of a medium gravity sour crude hydrocracking refinery with a 115,000 bbl/d nameplate capacity and a marketing division with 64 gasoline outlets, a home heating business and a commercial and wholesale petroleum products business, all located in the Province of Newfoundland and Labrador. The marketing division has an average daily sales volume of approximately 11,000 barrels representing approximately a 20% share of the Newfoundland market.

During the Third Quarter of 2007, our downstream operations consumed $23.4 million of cash as compared to $94.9 million and $138.4 million generated in the First and Second Quarters of 2007. The Third Quarter performance is primarily the result of the significant erosion of North American refining margins as the full impact of the higher crude oil feedstock costs did not flow through to higher prices for gasoline and distillate products and to a lesser extent, reduced throughput late in the quarter as the refinery commenced a planned shutdown to replace and regenerate catalyst on the Isomax and Platformer units as well as complete routine inspection and maintenance of select pipes and vessels in these units. Additional costs incurred for the planned shutdown also have an impact on Third Quarter performance. The following summarizes the North Atlantic financial and operational information for the three and nine month period ended September 30, 2007 as well as the three month periods ended June 30, 2007 and March 31, 2007:

(in $000s except where noted)	**Three Months Ended September 30, 2007**	Three Months Ended June 30, 2007	Three Months Ended March 31, 2007	**Nine Months Ended September 30, 2007**
Revenues	**789,612**	900,387	784,045	**2,474,044**
Purchased products for resale and processing	**747,011**	708,642	632,296	**2,087,949**
Gross Margin(1)	**42,601**	191,745	151,749	**386,095**
Costs and expenses				
Operating	**24,774**	26,584	25,361	**76,719**
Purchased energy	**22,340**	18,337	24,000	**64,677**
Turnaround and catalyst	**6,622**	-	-	**6,622**
Marketing	**10,673**	9,059	7,343	**27,075**
General and Administrative	**522**	402	300	**1,224**
Unrealized loss on risk management contracts	**4,469**	3,164	-	**7,633**
Depreciation and amortization	**17,280**	18,185	19,389	**54,854**
Earnings (loss) from operations(1)	**(44,079)**	116,014	75,356	**147,291**
Capital expenditures	**12,468**	9,871	4,883	**27,222**
Feedstock volume (bbl/day)	**103,983**	115,570	113,711	**111,052**
Yield (000's barrels)				
Gasoline and related products	**3,073**	3,379	3,310	**9,762**
Ultra low sulphur diesel	**3,596**	4,020	4,213	**11,829**
Heavy fuel oil	**2,785**	2,950	2,745	**8,480**
Total	**9,454**	10,349	10,268	**30,071**
Average Refining Margin (US$bbl)	**$3.08**	$15.64	$11.85	**$10.57**

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

Overview of Downstream Operations

During the Third Quarter of 2007, the downstream operations reported a loss from operations of $44.1 million, a $160.1 million drop from the $116.0 million earned in the prior quarter. The change in profitability during the Third Quarter is primarily the result of the costs of our crude oil feedstock increasing an average of US$12.84 per barrel while the average selling price for our distillates and heavy fuel oil only increased by US$3.22 and US$5.42 per barrel, respectively, and the average selling price for gasoline dropped by US$9.58 per barrel. In addition, our throughput was reduced by a planned maintenance shutdown, the cost of purchased energy increased by $4.0 million over the previous quarter and we incurred $6.6 million of turnaround and catalyst costs related to the planned shutdown of the Isomax and Platformer units.

During the three months ended September 30, 2007, the price of West Texas Intermediate ("WTI") increased by 16% from US$65.03 per barrel during the prior quarter to US$75.38 per barrel while the combined cost of our crude oil feedstock increased by 21% excluding purchases of vacuum gas oil ("VGO"). This higher than expected increase in feedstock costs is attributed to a narrowing of the differential between the price of medium gravity sour crude oil from the Middle East and the North American WTI benchmark price for light sweet crude oil as well as the carryover of narrow differentials on an inventory of Russian crude oil purchased in the previous quarter. Meanwhile, the price of VGO increased by 26% (or US$18.16 per barrel) from US$70.04 to US$88.20 also contributing to higher feedstock costs relative to the selling prices of refined products.

As expected, the yield of refined products during the Third Quarter was 98.8% consisting of 33% gasoline, 38% distillates and 29% heavy fuel oil as compared to a yield of 98.4% consisting of 32% gasoline, 39% distillates and 29% heavy fuel oil in the prior quarter. For the three months ended September 30, 2007, feedstock throughput averaged 103,983 bbls/d composed of 94,774 bbls/d of crude oil and 9,209 bbls/d of VGO as compared to 114,646 bbls/d composed of 104,530 barrels of crude oil and 10,116 barrels of VGO during the prior six month period.

During the Third Quarter, we initiated the planned shutdown of the Isomax and Platformer and rescheduled the shutdown of our crude and vacuum units from the spring of 2008 as originally planned to immediately follow the shutdown of the Isomax and Platformer units in mid October of 2007. This will better position North Atlantic to benefit from anticipated higher refinery margins in early 2008. In addition, it has resulted in an acceleration of maintenance costs and a reduction in throughput during the Third Quarter to 103,983 bbl/day as compared to 113,711 bbl/day and 115,570 bbl/day for the First and Second Quarters of 2007, respectively, as well as lowering throughput expectations for October and November of 2007 to approximately 42,500 bbls/d prior to returning to full production of over 117,000 bbls/d in December 2007.

Refining Benchmark Prices

The refining industry has numerous benchmark 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) produces one barrel of RBOB gasoline and one barrel of heating oil delivered to the New York market, where product prices are set in relation to NYMEX gasoline and NYMEX heating oil prices. The following average pricing indicators are provided as reference points with which to index the North Atlantic refinery's performance:

	Three Months Ended September 30, 2007	Three Months Ended June 30, 2007	Three Months Ended March 31, 2007	**Nine Months Ended September 30, 2007**
West Texas Intermediate crude oil				
(US$ per barrel)	**75.38**	65.03	58.16	**66.19**
Brent crude oil (US$ per barrel)	**74.87**	68.76	57.67	**67.10**
RBOB gasoline (US$ per barrel/US$ per gallon)	**87.02/2.07**	93.69/2.23	70.68/1.68	**83.80/2.00**
Heating Oil (US$ per barrel/US$ per gallon)	**87.86/2.09**	80.26/1.91	69.78/1.66	**79.30/1.89**
2-1-1 Crack Spread (US$ per barrel)	**12.06**	21.95	12.07	**15.36**
Canadian / US dollar exchange rate	**0.957**	0.911	0.854	**0.907**

As compared to the "2-1-1 Crack Spread" industry indicator, the Refinery's production differs in that it also produces approximately 25% to 30% heavy fuel oil not represented in the "2-1-1 Crack Spread" indicator. This heavy fuel oil production typically sells at US$15.00 to US$20.00 lower than the WTI benchmark price resulting in a negative contribution to our downstream's gross margin. Our Refinery also processes a medium gravity sour crude oil rather than a WTI quality of light sweet crude oil which generally sells at a discount to the WTI benchmark price ranging from US$3.00 to US$10.00. In addition, we purchase approximately 8,000 to 10,000 bbl/d of VGO to optimize the throughput of our hydrocracker unit which is valued at a premium to the WTI benchmark price.

During the Third Quarter of 2007, the NYMEX price of RBOB gasoline decreased by 7% while the price of heating oil increased by 9% as the WTI benchmark price increased by 16% resulting in a 45% reduction to the "2-1-1 Crack Spread" as compared to the prior quarter. The benchmark crack spreads for RBOB gasoline of US $11.64/bbl and US$12.48/bbl for heating oil reflect reductions of 59% and 18%, respectively, as compared to the prior quarter.

Refinery Feedstock

North Atlantic purchases its crude oil feedstock from Vitol Refining S.A. pursuant to the terms of the Supply and Offtake Agreement which includes the financing and operational hedging of crude oil inventory prior to its processing. This enables the price of our crude oil purchases to float with reference to the WTI benchmark price for the period from pricing through to the date it is processed by the Refinery. For a more complete description of the Supply and Offtake Agreement, see the description of the Supply and Offtake Agreement on page 53 of our Annual Information Form for the year ended December 31, 2006 filed on SEDAR at www.sedar.com. The terms of the Supply and Offtake Agreement include pricing formulas for feedstock whereby the price of feedstock consumed by the Refinery from one Wednesday to the next is determined using an average WTI benchmark price for the following Monday through Friday period adjusted for the actual shipping and product quality differentials. This averaging of WTI prices based on a subsequent period accelerates the impact of pricing trends and results in North Atlantic's pricing being based on a slightly different time period than the monthly average WTI benchmark price.

The cost and volume of North Atlantic's crude oil feedstock for the three months ended September 30, 2007 and June 30, 2007 were as follows:

	Three Months Ended September 30, 2007			**Three Months Ended June 30, 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)
Basrah	**478,504**	**6,384**	**71.73**	**436,452**	**6,793**	**58.53**
Hamaca	**90,792**	**1,210**	**71.81**	**75,524**	**1,215**	**56.63**
Urals	**85,304**	**1,125**	**72.57**	**109,631**	**1,516**	**65.88**
Crude Oil Feedstock	**654,600**	**8,719**	**71.85**	**621,607**	**9,524**	**59.46**
Vacuum Gas Oil	**78,060**	**847**	**88.20**	**76,351**	**993**	**70.04**
	732,660	**9,566**	**73.30**	**697,958**	**10,517**	**60.46**
Other costs	**642**			**542**		
	733,302			**698,500**		

(1) Cost of feedstock includes all costs of transporting the crude oil to North Atlantic's refinery.

During the Third Quarter of 2007, the Refinery feedstock consisted of 94,774 bbl/d of medium sour crude oil (approximately 73% Basrah from the Middle East, 14% Hamaca from Venezula and 13% Urals from Russia) and 9,209 bbl/d of VGO as compared to 104,659 bbl/d of medium sour crude oil (approximately 71% Basrah from the Middle East, 13% Hamaca from Venezula and 16% Urals from Russia) and 10,911 bbls/d of VGO in the prior quarter. During the Third Quarter, the shutdown of the hydrocracker unit resulted in lower throughput, including less consumption of VGO, as compared to the prior quarter. Also during the Third Quarter, the crude unit and vacuum tower encountered fouling associated with "near-end-of-run" performance which resulted in a lower yield of VGO requiring relativley more purchases of this material from third parties. The turnaround of the crude unit and vacuum tower now planned for the Fourth Quarter of 2007 is expected to resolve the fouling issues.

The average discount between our purchases of Basrah and the WTI benchmark price during the Third Quarter was US$3.65 as compared to US$6.61 and US$6.50 for the First and Second Quarters, respectively, contributing to a cost increase of 39% and 23% for our Basrah feedstock over the previous quarters, while the average WTI benchmark price for the Third Quarter increased by 30% and 16% over the previous quarters. Our average discount and price changes for Hamaca have generally mirrored those for Basrah over the first nine months of 2007 while the average discount for Urals versus the WTI benchmark during the Third Quarter was US$2.81 as compared to a discount of US$8.61 and a premium of US$0.85 for the First and Second Quarters, respectively. The tightening of these discounts to the WTI benchmark price during the Third Quarter has resulted in higher costs of feedstock and a reduction of the North Atlantic refining margin of approximately US$3.50 per barrel.

Refined Products

The revenues in our downstream operations are dependent on the yield of refined products and their sales value. Our product yields are impacted by the crude oil feedstock qualities as well as refinery performance. A summary of North Atlantic's product yield, pricing and revenue for the three month periods ended September 30, 2007 and June 30, 2007 are as follows:

	Three Months Ended September 30, 2007			Three Months Ended June 30, 2007		
	Refinery Revenues	Volume	Sales Price[1]	Refinery Revenues	Volume	Sales Price[1]
	(000's of Cdn $)	(000s of bbls)	($ per bbl/ $ per US gal)	(000's of Cdn $)	(000s of bbls)	($ per bbl/ $ per US gal)
Gasoline and related products	**249,628**	**2,800**	**85.32/2.03**	334,391	3,210	94.90/2.26
Low & ultra low sulphur diesel & jet fuel	**344,521**	**3,719**	**88.65/2.11**	366,846	3,912	85.43/2.03
Heavy fuel oil	**169,926**	**2,791**	**58.27/1.39**	177,873	3,066	52.85/1.26
	764,075	**9,310**	**82.07/1.95**	879,110	10,188	86.29/2.05
Inventory adjustment		**144**			161	
Total production		**9,454**			10,349	
Yield (as a % of Feedstock) [2]		**98.83%**			98.40%	

[1] Average product sales prices are based on the sales at the North Atlantic refinery loading docks.

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

During the Third Quarter of 2007, North Atlantic's gasoline sales were 29% of feedstock consumed, off by 2% from 31% in the Second Quarter, while the sales of ultra low sulphur diesel and jet fuel at 39% were 2% higher than in the previous quarter. Our heavy fuel oil sales at 29% were unchanged from the previous quarter. North Atlantic's sales closely approximate the Refinery's yields as the Supply and Offtake Agreement requires substantially all refined products produced be purchased by Vitol Refining S.A. on a weekly basis with the exception of jet fuel and other refined products marketed in the Province of Newfoundland and Labrador by North Atlantic.

Relative to the WTI benchmark price for crude oil, our refining margin/crack spread for the Third Quarter was US$3.16 per barrel as compared to US$13.58 in the Second Quarter and US$6.13 in the First Quarter. North

Atlantic's crack spread is a combination of its gasoline, distillates (diesel and jet fuel) and heavy fuel oil crack spreads. Relative to the WTI benchmark price, North Atlantic's crack spread on gasoline dropped 67% during the Third Quarter from US$29.87 per barrel during the Second Quarter of 2007 to US$9.94 while the crack spread on distillates similarly dropped 35% from US$20.40 per barrel to US$13.27. These two products comprise 70% of North Atlantic's refined product sales. Again relative to the WTI benchmark price, North Atlantic's negative margin on heavy fuel oil increased by 40% during the Third Quarter from a discount of US$12.18 to a discount of US$17.11. The deteriorating refined product margins coupled with the impact of a strengthening Canadian dollar on this US dollar denominated business has resulted in a 68% drop in North Atlantic's refining crack spread compared to the first six months of 2007.

Relative to the benchmark NYMEX RBOB gasoline price, North Atlantic realized a discount of US$0.04 per US gallon for its gasoline production during the Third Quarter as compared to a premium of US$0.03 received in the previous quarter. For its ultra low sulphur diesel and jet fuel products, North Atlantic received a US$0.02 per gallon premium in the current quarter as compared to a US$0.12 per gallon premium in the prior quarter relative to the NYMEX heating oil benchmark price. Generally, North Atlantic's gasoline price will closely mirror the NYMEX reference price while its diesel fuel and jet fuel command a premium over the NYMEX heating oil price reflecting its higher product quality after adjustment for shipping costs to the New York harbour. However, from time-to-time, there will be modest differences in the differential between the physical selling prices for North Atlantic's refined products in the New York Harbour and the NYMEX benchmark prices as well as there is an impact from the time delay in the Supply and Offtake Agreement's pricing of refined products which is similar to the feedstock pricing which results in a ten day lag in pricing relative to the NYMEX benchmark prices.

Relative to the WTI benchmark price for light sweet crude oil, the selling price of North Atlantic's heavy fuel oil is discounted to reflect the heavier gravity and sulphur content. During the Third Quarter, this discount was US$17.11 as compared to US$12.18 in the Second Quarter representing a US$4.93 increase during the quarter and a discount of 23% from the WTI benchmark price for the current quarter as compared to 19% for the previous quarter. The heavy fuel oil produced by North Atlantic presents an opportunity to re-configure the Refinery to produce more gasoline and/or diesel fuel which is the objective of the $22 million visbreaker enhancement approved in March 2007 and is expected to be commissioned in September 2008.

Gross Margin

Our downstream gross margin consists of the crack spread from its refinery operations as well as the margin on its marketing and other related businesses. A summary of the gross margin contribution from the refinery and marketing operations for each three month period ended September 30, 2007 and June 30, 2007 are as follows:

	Three Months Ended September 30, 2007			Three Months Ended June 30, 2007		
(000's of Canadian dollars)	Refining	Marketing	Total	Refining	Marketing	Total
Sales revenue(1)	764,075	158,292	789,612	879,110	115,404	900,387
Cost of products for processing and resale(1)	733,302	146,464	747,011	698,500	104,269	708,642
Gross margin(2)	30,773	11,828	42,601	180,610	11,135	191,745
Average Refining Margin (US$/bbl)	$3.08			$15.64		

(1) The North Atlantic sales revenue and cost of products for processing and resale are net of inter-segment sales of $132,755,000 reflecting the refined products produced by the Refinery Operations and sold by the Marketing Operations for the three months ended September 30, 2007 ($94,127,000 for the three months ended June 30, 2007)

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

During the three months ended September 30, 2007, our downstream gross margin of $42.6 million represents a decrease of $149.1 million from the Second Quarter. This 78% drop in gross margin is entirely related to the refinery operations as the marketing and other related businesses reported a gross margin of $11.8 million for the Third Quarter, relatively unchanged from the $11.1 million reported in the previous quarter. As discussed above, this quarter-over-quarter drop in refining margin is attributed to higher feedstock costs due to the tightening of the discounts for our Basrah and Hamaca crudes and a higher premium for VGO, a significant erosion of the crack spreads for gasoline and distillates and a widening of the discounts on the sale of heavy fuel oil plus the impact of a strengthening Canadian dollar relative to our refining business which operates in U.S. dollars.

The gross margin from North Atlantic's marketing operations of $11.8 million, up $0.7 million from the prior period, is comprised of the margin from both the retail and wholesale distribution of gasoline, home heating fuels and related appliances as well as the revenues from marine services including tugboat revenues.

Price Risk Management

Subsequent to acquiring North Atlantic, Harvest's participation in the crude oil value chain extended to include the price of refined products produced by North Atlantic, principally gasoline, distillates (which encompasses low sulphur diesel fuel, jet fuel and heating oil) and heavy fuel oil. This results in our price protection of future cash flows including the refining margins/crack spreads on refined products. For purposes of this MD&A and the segmented reporting in Note 17 of our financial statements, our price risk management contracts are presented as either relating to our upstream operations or our downstream operations according to the price exposure that is being managed.

During the Second and Third Quarters of 2007, we have entered into price risk management contracts with respect of:

- 12,000 bbl/d of NYMEX heating oil for the period from January 2008 to December 2008,
- 8,000 bbl/d of Platts heavy fuel oil for the period from January 2008 to December 2008
- 4,000 bbl/d of NYMEX heating oil for the period from January 2009 to June 2009, and
- 6,000 bbl/d of Platts heavy fuel oil for the period January 2009 through June 2009.

We have used a combination of "price collars" which provides a fixed floor price and price cap as well as a "three way" structure which provides a floor price with a premium over market price on the downside and a price cap. Details of our price risk management contracts outstanding at September 30, 2007 are included in Note 16 of our interim consolidated financial statements for the three and nine month periods ended September 30, 2007 filed on SEDAR at www.sedar.com.

Subsequent to the end of the Third Quarter, we entered into additional "three way" contracts in respect of:

- 8,000 bbl/d of NYMEX heating oil for the period from January 2009 to June 2009,
- 2,000 bbl/d of Platts fuel oil for the period January 2009 through June 2009, and
- 6,000 bbl/d of NYMEX RBOB crack spread for the period July 2008 through December 2008.

Concurrent with entering into the price risk management contracts for refined products, we enter into inter-company contracts between our upstream operations and our downstream operations to shift the WTI price protection to our upstream operations resulting in our downstream operations retaining a net crack spread exposure on refined products. See the details of these inter-company contracts in our discussion of Price Risk Management in the Upstream Operations section of this MD&A.

Net of our inter-company contracts with our upstream operations, our downstream operations have price risk management contracts in place that result in refining margin/crack spread protection on approximately 28% of our anticipated heating oil production for 2008, 24% of our anticipated heavy fuel oil production for 2008, and 15% of our anticipated RBOB gasoline production for the period from July 2008 through December 2008 as well as 28% of our anticipated heating oil production and 24% of our anticipated heavy fuel oil production, respectively for the first half of 2009.

For the three month periods ended September 30, 2007 and June 30, 2007, the refined products contracts resulted in net unrealized losses of $15.7 million and $8.7 million respectively of which $4.5 million and $3.2 million respectively are recognized in the North Atlantic operations as a net loss on a crack spread position and $11.2 million and $5.5 million respectively is recognized in the upstream operations as a loss on the WTI portion of the contract.

The table below provides a summary of net gains and losses on our price risk management contracts for the three month periods ended September 30, 2007 and June 30, 2007:

(000s)	Three Months Ended September 30, 2007			Three Months Ended June 30, 2007		
	Heating Oil	Fuel Oil	Total	Heating Oil	Fuel Oil	Total
Unrealized loss on refined product price risk management contracts	$ (8,816)	$ (6,881)	$ (15,697)	$ (6,156)	$ (2,495)	$ (8,651)
Unrealized gain on inter-company WTI portion of refined product price risk management contracts	7,316	3,912	11,228	3,303	2,184	5,487
Net unrealized loss on price risk management contracts	$ (1,500)	$ (2,969)	$ (4,469)	$ (2,853)	$ (311)	$ (3,164)

Operating Expenses

A summary of North Atlantic's operating costs for the downstream operations for the three month periods ended September 30, 2007 and June 30, 2007 are as follows:

	Three Months Ended September 30, 2007			**Three Months Ended June 30, 2007**		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	**Refining**	**Marketing**	**Total**
Turnaround and catalyst	**6,622**	**-**	**6,622**	**-**	**-**	**-**
Operating expense	**20,262**	**4,512**	**24,774**	**22,122**	**4,462**	**26,584**
Purchased energy	**22,340**	**-**	**22,340**	**18,337**	**-**	**18,337**
	49,224	**4,512**	**53,736**	**40,459**	**4,462**	**44,921**

Turnaround and catalyst expenditures consist of $2.6 million and $4.0 million respectively. Catalyst expenditures include the planned biannual top-bed catalyst change-out on the hydrocracker unit. Turnaround expenditures include planned major maintenance completed simultaneously with the catalyst change-out.

The largest component of Refinery's operating expense is salaries, wages and benefits which totaled $13.1 million during the Third Quarter of 2007 ($13.7 million for the three months ended June 30, 2007) while the other significant components were maintenance and repairs costs of $2.5 million ($3.0 million for the three months ended June 30, 2007), insurance of $1.5 million ($1.7 million for the three months ended June 30, 2007) and professional services of $1.5 million ($1.6 million for the three months ended June 30, 2007), which were all in line with expectations. During the Third Quarter, refining operating expenses were $2.12 per barrel as compared to $2.10 per barrel during the prior quarter. This is slightly lower than our expectations of approximately $2.20 to $2.40 per barrel due to the lower than anticipated throughput.

Purchased energy, consisting of low sulphur fuel oil and electric power, is required to provide heat and power to refinery operations, respectively. Our purchased energy costs increased to $2.34 per barrel during the Third Quarter of 2007 as compared to $1.74 per barrel during the Second Quarter as a result of the increased price of fuel oil and reduced throughputs. Our expectation is that purchased energy should average approximately $2.20 for a calendar year.

Marketing Expense

During the Third Quarter of 2007, marketing expense is comprised of $0.8 million of marketing fees (based on US$0.08 per barrel of feedstock) to acquire feedstock (compared to $1.0 million in the Second Quarter) and $9.9 million of "Time Value of Money" charges (compared to $8.1 million in the Second Quarter), both pursuant to the Supply and Offtake Agreement. The $1.8 million increase in the "Time Value of Money" charge in the Third Quarter reflect the higher cost of crude oil feedstock acquired in the Third Quarter relative to the Second Quarter.

Capital Expenditures

Capital spending for the first nine months of 2007 totaled $27.2 million with the Third Quarter accounting for $12.5 million of the total, tank recertification and rebuild account for $3.1 million, while the replacement of exchanger bundles for the hydrocracker unit was $2.0 million, and wash-water upgrade for the hydrocracker unit cost $1.2 million along with numerous other sustaining and improvement projects.

Depreciation and Amortization Expense

North Atlantic's depreciation and amortization expense for the downstream operations for the three months ended September 30, 2007 as well as June 30, 2007 is as follows:

	Three Months Ended September 30, 2007			Three Months Ended June 30, 2007		
(000's of Canadian dollars)	Refining	Marketing	Total	Refining	Marketing	Total
Tangible assets	**15,250**	**503**	**15,753**	**16,111**	**470**	**16,581**
Intangible assets	**1,163**	**364**	**1,527**	**1,221**	**383**	**1,604**
	16,413	**867**	**17,280**	**17,332**	**853**	**18,185**

The process units are amortized over an average useful life of 20-30 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

On October 19, 2006, we recorded $203.9 million of goodwill in connection with the acquisition of North Atlantic as the purchase price of the acquired business exceeded the fair value of the net identifiable assets and liabilities of that acquired business. As the refining assets are held in a self-sustaining subsidiary with a U.S. dollar functional currency, the value of the goodwill will be adjusted at each period end to reflect the changing U.S. dollar currency exchange rate. Goodwill will be assessed annually for impairment or more frequently if events or changes in circumstances occur that would reasonably be expected to reduce the fair value of the acquired business to a level below its carrying amount. To date, no charge for impairment of this goodwill has been made.

FINANCING AND OTHER

Interest Expense

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
(000s)	**2007**	2006	Change	**2007**	2006	Change
Interest on short term debt						
Bank loan	**$ -**	$ -	n/a	**$ 1,275**	$ -	100%
Convertible debentures	**606**	-	100%	**1,900**	-	100%
Amortization of deferred finance charges – short term debt	**-**	-	n/a	**1,811**	-	100%
	606	-	100%	**4,986**	-	100%
Interest on long-term debt						
Bank loan	**16,373**	5,797	182%	**52,903**	10,263	415%
Convertible debentures	**13,193**	4,674	182%	**43,587**	12,593	246%
$7^{7/8}$% Senior Notes	**5,523**	5,488	1%	**17,328**	16,785	3%
Amortization of deferred finance charges – long term debt	**675**	726	(7%)	**2,022**	2,932	(31%)
	35,764	16,685	114%	**115,840**	42,573	172%
Total interest expense	**$ 36,370**	$ 16,685	118%	**$ 120,82(**	$ 42,573	184%

Interest expense, which includes the amortization of related financing costs, was $19.7 million and $78.3 million higher for the three and nine month periods ended September 30, 2007, respectively than in the same periods in the prior year. Of this increase, the amount related to bank loan interest (both short term and long term) of $10.6 million and $43.9 million for the three month and nine month periods, respectively, is the result of the significant increase in the drawn amounts on our credit facilities. A further increase of $9.1 million and $32.9 million for the three and nine month periods, respectively, is related to the increase in the principal amount of convertible debentures outstanding.

At the end of the Third Quarter of 2007, we had drawn approximately $1,205.1 million of bank borrowings as compared to $1,048.0 million at the end of the Second Quarter of 2007 and $1,595.7 million at the end of December 31, 2006. During the First Quarter of 2007, our bank borrowings were reduced with the net proceeds of $357.4 million from our issuance of 6,146,750 trust units and $230 million principal amount of 7.25% Debentures due 2014. During the Second Quarter of 2007, our bank borrowings were reduced by a combination of net proceeds of $218.5 million from our issuance of 7,302,500 Trust Units and surplus cash after capital spending distribution requirements. In the Third Quarter of 2007, we increased our bank borrowings by $157.0 million, of which $139.3 million is attributed to the acquisition of Grand during the quarter. Currently, the interest on our Three Year Extendible Revolving Facility is at a floating rate based on 70 basis points over bankers' acceptances for Canadian dollar borrowings and 70 basis points over the London Inter Bank Order Rate for US dollar borrowings. During the Third Quarter of 2007, our interest charges on bank loans aggregated to $16.4 million as compared to $17.5 million and $20.3 million during the Second and First Quarters of the year, respectively, reflecting effective interest rates of 5.74%, 5.46% and 5.14%, respectively. Further details on our credit facilities are included under "Liquidity and Capital Resources".

The interest on our convertible debentures totaled $13.8 million and $45.5 million during the three and nine months ended September 30, 2007, respectively, and is based on the effective yield of the debt component of the convertible debentures. Details on the convertible debentures outstanding are fully described in Note 11 to the interim consolidated financial statements for the three and nine month periods ended September 30, 2007 filed on SEDAR at www.sedar.com. During the Third Quarter of 2007, there were $35.1 million of principal amount of convertible debentures converted to 1,283,413 Trust Units.

The interest on our 77/8% Senior Notes totaled $5.5 million and $17.3 million during the three and nine months ended September 30, 2007, respectively. Like 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. Due to the recent strength of the Canadian dollar relative to the U.S. dollar, our cash interest expense has been lowered as interest on these notes is paid in U.S. dollars.

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 and bridge facilities, all totaling $3.8 million for the nine months ended September 30, 2007.

Non-Controlling Interest

The non-controlling interest in the first quarter of 2006 represents the net income attributed to non-controlling interest holders for the period. The exchangeable shares that give rise to the non-controlling interest were issued by Harvest Operations as partial consideration for the purchase of a corporate entity in 2004. In 2006, 156,067 exchangeable shares were converted to trust units under the plan of arrangement with Viking and the remaining 26,902 exchangeable shares were purchased and cancelled for a total cash payment of $1.0 million.

Currency Exchange Gains and Losses

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 LIBOR bank loans, 77/8% Senior Notes as well as any other U.S. dollar cash balances. Since December 31, 2006, the Canadian dollar has strengthened significantly compared to the U.S dollar. As a result we have earned an unrealized foreign exchange gain on our 77/8% Senior Notes of $41.5 million during the first nine months of 2007. 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. In addition, during the first nine months of 2007 we also incurred unrealized foreign exchange losses and realized foreign exchange gains on North Atlantic transactions of $16.7 million and $2.4 million, respectively.

North Atlantic is considered a self-sustaining operation with a U.S. dollar functional currency. The foreign exchange gains and losses incurred by North Atlantic relate to Canadian dollar transactions converted to U.S. dollars as their functional currency is U.S. dollars.

Future Income Tax

With the enactment of Bill C-52 in the Second Quarter of 2007, Harvest recorded a future income tax expense of $177.7 million to reflect the impact of the 31.5% tax to be applied to distributions from Canadian publicly traded income trusts commencing in January 2011. In the Third Quarter of 2007, we recorded a further adjustment of $54.4 million to reduce this liability for a year-to-date future income tax expense of $123.3 million. This reduction is primarily the result of a shift in the utilization during the period prior to January 2011 of net profits interest payments that have restored the anticipated tax basis of assets in a wholly-owned subsidiary. Our future tax liability at September 30, 2007 reflects the tax liability inherent to the temporary differences between the book basis and the tax basis of the assets and liabilities held by our mutual fund trust, wholly owned corporations and other flow-through subsidiaries. While net income in the three and nine months ended September 30, 2007 has been significantly impacted by this future income tax adjustment, there is no impact on cash from operating activities.

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	**1,453,819**	-	65,000	1,388,819	-
Interest on long-term debt(4)	**251,878**	22,039	173,526	56,313	-
Interest on convertible debentures(3)	**264,749**	12,293	93,366	90,364	68,726
Operating and premise leases	**28,808**	2,233	13,957	10,756	1,862
Purchase commitments(5)	**14,741**	11,861	2,880	-	-
Asset retirement obligations(6)	**711,299**	5,458	13,058	13,321	679,462
Transportation (7)	**4,086**	518	2,699	680	189
Pension contributions	**27,492**	195	3,345	4,805	19,147
Feedstock commitments	**600,283**	377,851	222,432	-	-
Total	**3,357,155**	432,448	590,263	1,565,058	769,386

(1) As at September 30, 2007, we had entered into physical and financial contracts for production with average deliveries of approximately 25,000 boe/d for the remainder of 2007, and 10,000 boe/d in 2008. We have also entered into financial contracts for our downstream production of refined products with average deliveries of approximately 20,000 bbl/d in 2008 and 10,000 bbl/d in 2009. We have also entered into financial contracts to minimize our exposure to fluctuating electricity prices. Please see Note 16 to the interim consolidated financial statements for further details.
(2) Assumes that the outstanding convertible debentures either convert at the holders' option or are redeemed for Units at our option.
(3) Assumes no conversions and redemption by Harvest for trust units at the end of the second redemption period. Only cash commitments are presented.
(4) Assumes constant foreign exchange rate.
(5) Relates to drilling commitments, AFE committments and downstream purchase commitments.
(6) Represents the undiscounted obligation by period
(7) Relates to firm transportation commitment on the Nova pipeline.

Off Balance Sheet Arrangements

We have a number of operating leases in place on 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 months ended September 30, 2007, Vitol Refining S.A. purchased U.S. $128.5 million and U.S. $259.7 million of Iraqi crude oil, respectively, 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, 2007, $34.0 million related to these purchases is included in Harvest's accounts payable and accrued liabilities, and $55.5 million is included in the total feedstock commitments disclosed at the end of September 2007. Subsequent to September 30, 2007, no further commitments have been incurred relating to crude oil purchases by Vitol Refining S.A from this private company related to a Harvest director.

CHANGE IN ACCOUNTING POLICIES

Effective January 1, 2007, we have retrospectively without restatement adopted the new accounting standards of the Canadian Institute of Chartered Accountants respecting, "Financial Instruments – Recognition and Measurement"; "Comprehensive Income"; and "Financial Instruments – Disclosure and Presentation". The impact of adopting these new standards is reflected in our financial results for the nine month period ended September 30, 2007 while the prior year comparative financial statements have not been restated. While the new standards change how we account for financial instruments, there were no material impacts on our results for the three and nine month periods ended September 30, 2007, with the most significant difference being that the deferred charges previously presented as an asset are now netted against the respective debt and amortized to income using an effective interest rate. For a description of the new accounting standards and the impact on our financial statements of adopting such standards see Note 2 to the interim consolidated financial statements for the three and nine month periods ended September 30, 2007.

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2007, our capitalization was relatively unchanged compared to the end of the Second Quarter as we increased bank debt to fund our $139.3 million acquisition of Grand in August 2007 and reduced the principal amount of convertible debentures outstanding by $35.1 million with the conversion of debentures into 1,283,413 trust units. Whereas during the first six months of 2007, we issued a total of $575.9 million of convertible debentures and trust units to repay bank debt related to our acquisition of North Atlantic in 2006, while our cash from operating activities was more than sufficient to fund our cash distributions paid, capital spending program and acquisitions. The following summarizes our capitalization as of September 30 and June 30, 2007 as well as December 31, 2006:

(in millions)	**September 30, 2007**	June 30, 2007	December 31, 2006
DEBT			
Credit Facilities			
- Three Year Extendible Revolving Credit Facility	**$1,205.1**	$1,048.0	$1,306.0
- Senior Secured Bridge Facility	-	-	289.7
Total Bank Debt	**1,205.1**	1,048.0	1,595.7
$7^{7/8}$ % Senior Notes Due 2011 (US$250 million) (1)	**248.7**	266.4	291.4
Convertible Debentures, at principal amount			
10.5% Debentures Due 2008	**24.3**	25.5	26.6
9% Debentures Due 2009	**1.0**	1.1	1.2
8% Debentures Due 2009	**1.8**	1.8	2.2
6.5% Debentures Due 2010	**37.1**	37.9	37.9
6.4% Debentures Due 2012	**174.6**	174.6	174.8
7.25% Debentures Due 2013	**379.2**	379.4	379.5
7.25% Debentures Due 2014	**73.2**	106.0	-
Total Convertible Debentures	**691.2**	726.3	622.2
Total Debt	**2,145.0**	2,040.7	2,509.3

TRUST UNITS			
146,442,333 outstanding at September 30, 2007	**3,692.3**		
143,505,858 outstanding at June 30, 2007		3,610.8	
122,096,172 outstanding at December 31, 2006			3,046.9
TOTAL DEBT AND TRUST UNITS	**$5,837.3**	$5,651.5	$5,556.2
TOTAL DEBT TO TOTAL CAPITALIZATION	**37%**	36%	45%

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

At the end of the Second Quarter of 2007, we had extended the maturity date on $1,535 million of our $1.6 billion Three Year Extendible Revolving Credit Facility to April 2010 with $65 million retaining a March 2009 maturity date. Subsequent to the end of the Third Quarter, we received incremental commitments from existing lenders and re-assigned the $65 million portion of our credit facility maturing March 2009 to lenders who concurrently extended the maturity date on their incremental commitments to April 2010. For a complete description of our covenant-based credit agreement, see Note 10 to our audited consolidated financial statements for the year ended December 31, 2006 filed on SEDAR at www.sedar.com. This 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 (excluding 77/8% 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, 2007, our Bank Debt to annualized EBITDA (based on the first nine months of 2007) was 1.3 to 1.0, Total Debt (excluding convertible debentures) to annualized EBITDA was 1.5 to 1.0, while the Bank Debt to Total Capitalization was 20% and Total Debt to Total Capitalization was 37%. We had approximately $395 million of unused credit capacity at quarter's end.

Concurrent with the closing of the North Atlantic acquisition, North Atlantic 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 that Vitol be granted 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. For a more complete description of this Supply and Offtake Agreement, see the description of the Supply and Offtake Agreement on page 53 of our Annual Information Form for the year ended December 31, 2006 filed on SEDAR at www.sedar.com. During the Third Quarter of 2007, the working capital requirements provided by Vitol under the Supply and Offtake Agreement were extended to include the build-up of VGO, both internally produced and purchased, to enable the operation of the Isomax unit to process VGO while the crude unit and vacuum tower are shutdown in the Fourth Quarter. At the end of September 2007, Vitol held on our behalf 196,550 barrels of VGO inventory valued at US $16.3 million. Including the inventory of VGO, crude oil feedstock delivered and committed to be delivered to the Refinery and refined products held for Vitol, we estimate the outstanding commitments under the Supply and Offtake Agreement at September 30, 2007 to be approximately $600.3 million.

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 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 very long life with additional growth in profitability available by upgrading the heavy fuel oil currently produced by the Refinery and by investing in an expansion of the Refinery which should benefit from the incremental economics of 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 the excess of our cash from operating activities over distributions paid while we will generally rely on funding from some combination of the excess of our cash from operating activities over distributions paid, issuances of equity and increased debt for more significant acquisitions and growth initiatives. 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 the equity capital markets or incremental debt not be available to us, our ability to make the necessary expenditures to maintain or expand our assets may be impaired and result in reductions to future distributions paid to unitholders. In our upstream business, it is not possible to distinguish between expenditures to maintain productive capacity and spending to increase productive capacity due to the numerous factors impacting reserve reporting and the natural decline in reservoirs. Accordingly, maintenance capital is not disclosed separately.

On July 6, 2007 the Canadian Securities Administrators published National Policy Statement 41-201, requiring income trusts to discuss our distributions relative to net income. Our distributions will generally exceed net income reported in our financial statements as a result of significant non-cash charges recorded in our income statement. For example, we recorded $177.7 million in respect of future income tax expense in the Second Quarter of 2007 and recognized $77.1 million in unrealized gains on price risk management contracts in the Third Quarter of 2006. These non-cash revenues and expenses result in changes 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 Third Quarter of 2007, our distributions to unitholders exceeded our net income of $11.8 million by $154.5 million as compared to the prior year where our distributions to unitholders exceeded our net income of $107.8 million by $15.3 million. For the nine months ended September 30, 2007, our distributions to unitholders exceeded our net income of $87.9 million by $377.7 million as compared to the prior year where our distributions exceeded our net income of $134.5 million by $199.3 million. In instances where our distributions exceed our net earnings, a portion of the distribution may represent a return of capital rather than earnings.

During the nine months ended September 30, 2007, our cash from operating activities of $553.3 million exceeded distributions declared of $465.6 million ($136.4 million of which was reinvested through our distribution reinvestment plans) resulting in $87.7 million retained for our capital programs. During this period, our capital spending aggregated to $297.3 million while the net cash required for our acquisition/divestiture program aggregated to $148.5 million including our purchase of Grand in the Third Quarter. The excess of the requirements for our capital spending and acquisition/divestiture program has been funded by borrowings under our credit facility and proceeds from our distribution reinvestment plan. In comparison, during the same period in the prior year we had cash from operating activities $367.3 million and declared distributions of $333.8 million ($133.8 million was reinvested through our distribution reinvestment plans) with aggregate capital spending of $286.5 million and an acquisition program aggregating to $587.5 million including the acquisition of Birchill Resources.

During the first nine months of 2007, our distributions declared totaled $465.6 million, representing 84% of cash from operating activities, of which $136.4 million was settled with trust units as approximately 30% of our Unitholders have chosen to participate in our distribution reinvestment plans.

Management, together with the Board of Directors of Harvest, continually assess the level of our monthly distributions in light of commodity price expectations, production and throughput projections, debt leverage and spending plans. On July 8, 2007, we announced the declaration of a $0.38 per trust unit distribution for each of July, August and September 2007 based on the then forecasted commodity prices and expected operating performance. However, on October 4, 2007, we announced the declaration of a $0.38 per trust unit distribution for only the month of October 2007 to enable a better assessment of a number of factors including the outcome of the royalty review by the province of Alberta, approval of our 2008 budget and a more complete assessment of Fourth Quarter expectations prior to declaring distributions for the months of November and December 2007. Distributions of $0.30 per trust unit for the months of November and December 2007, as well as January and February 2008, announced today, reflect our expectations.

During the Third Quarter, the trading value of our trust units dropped from a price of $32.95 at the beginning of the quarter to $26.77 at the end of the quarter. This trend in trading value is generally attributed to the typical seasonal decline in refining margins, uncertainty created with the royalty review by the province of

Alberta and weak natural gas prices, offset by very strong crude oil prices and the effects of a strengthened Canadian dollar. The following summarizes the trading value of our trust units during 2007:

	Trading Price		
Month	**High**	**Low**	**Volume**
TSX Trading			
January 2007	$ 26.22	$ 23.20	12,822,502
February 2007	$ 27.49	$ 24.81	10,036,635
March 2007	$ 29.22	$ 25.90	11,430,584
April 2007	$ 31.10	$ 27.74	10,244,956
May 2007	$ 33.16	$ 30.25	13,984,905
June 2007	$ 34.48	$ 31.38	19,605,824
July 2007	$ 34.97	$ 29.50	19,478,671
August 2007	$ 31.52	$ 26.10	17,373,101
September 2007	$ 29.40	$ 25.18	15,463,720
October 2007	$ 28.39	$ 25.92	13,236,903
NYSE Trading (in US$)			
January 2007	$ 22.20	$ 19.70	16,693,600
February 2007	$ 23.55	$ 21.18	10,059,454
March 2007	$ 25.22	$ 21.97	12,316,050
April 2007	$ 28.07	$ 24.00	10,038,123
May 2007	$ 30.70	$ 27.05	14,253,739
June 2007	$ 32.46	$ 29.47	13,474,838
July 2007	$ 33.97	$ 27.15	17,505,628
August 2007	$ 29.74	$ 24.29	23,146,747
September 2007	$ 27.94	$ 25.15	19,625,622
October 2007	$ 29.11	$ 25.94	20,887,843

We are authorized to issue an unlimited number of trust units and as of November 8, 2007, we had 147,072,879 trust units outstanding, 3,893,033 of Unit Appreciation Rights outstanding (of which 601,300 were vested) and 338,505 awards issued under the Unit Awards Incentive Plan (of which 112,605 were vested). In addition, we have seven series of convertible debentures outstanding that are convertible into 20,475,027 trust units including one issue, $24,258,000 principal amount of 10.5% debentures, that matures January 2008 which we intend to settle with the issuance of 836,483 trust units.

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

Distributions to Unitholders and Taxability

In the Third Quarter of 2007, we declared monthly distributions of $0.38 per trust unit ($166.3 million) to Unitholders, 87% of our cash from operating activities, and have declared a monthly distribution of $0.38 per trust unit for the month of October 2007, while waiting for further clarity on financial results, annual budget expectations and the impact of the royalty review by the Province of Alberta prior to declaring distributions for the months of November and December 2007. The $43.2 million increase in distributions declared during the Third Quarter of 2007 as compared to the prior year is primarily due to an increase of approximately 35.5 million trust units outstanding following the acquisitions of Birchill and North Atlantic in 2006 along with issuance under our distribution re-investment plans.

	Three Months Ended September 30			Nine Months Ended September 30		
(000s except per trust unit amounts)	**2007**	2006	Change	**2007**	2006	Change
Distributions declared	**$ 166,271**	$ 123,112	35%	**$ 465,598**	$ 333,813	39%
Per trust unit	**$ 1.14**	$ 1.14	-	**$ 3.42**	$ 3.39	1%
Taxability of distributions	**100%**	100%	-	**100%**	100%	-
Distributions as a percentage of cash from operating activities	**87%**	86%	1%	**84%**	91%	(7%)

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. As such, we expect that the current year distributions to our Unitholders will be 100% taxable and that the Trust will have no taxable income.

OUTLOOK

At the end of the Third Quarter of 2007, our upstream production was approximately 60,000 boe/day with a further 1,000 boe/day of natural gas production shut-in due to a maintenance turnaround of a third party processing facility and approximately 1,500 boe/day of production from this year's drilling program to be tied-in. Our 2007 drilling program is now substantially complete with our upstream capital focused on tying-in our drilling results. We anticipate that our Fourth Quarter production will average approximately 60,500 boe/day, bringing our annual daily average for 2007 to approximately 61,000 boe/day while our operating costs will continue to run in the $13.00 range including the cost of turnarounds and some weakening of cost pressures from the service industry. For the Fourth Quarter 2007, we have price risk management contracts on approximately 71% of our net oil production to provide an average floor price of US$57.00 on 25,000 bbls/d (relative to the West Texas Intermediate benchmark price) including upside participation if prices rise above US$58.75 on 20,000 bbls/d.

In our downstream operations the Isomax unit was shutdown on September 21, 2007 to replace a catalyst bed and change-out its heat exchangers with feedstock successfully re-introduced on October 17, 2007. Following the re-start of the Isomax, we took the crude unit and vacuum tower out of service; this was an acceleration of the planned shutdown in the spring of 2008 intended to improve the overall yield of gasoline and distillate products in 2008. The Isomax shutdown has resulted in less gasoline production in the Third Quarter while the work on the crude unit and vacuum tower will extend the period of partial refinery operation in the Fourth Quarter of 2007 with an expectation of improved results in 2008. The revised cost of capital projects for 2007 is $48 million while the cost of catalyst replacement and maintenance turnaround expense is expected to aggregate to $11 million and $16 million, respectively, with the Fourth Quarter contribution to cash from operating activities expected to be less than break-even.

The unprecedented rise in WTI prices early in the Fourth Quarter has provided us with opportunities: our Fourth Quarter oil sales revenues will participate in approximately 72% of pricing over US$58.75 on 20,000 bbl/d and we added to our price risk management positions such that, for 2008, our contracts cover:

- 93% of our anticipated oil production for the first six months of 2008;
- 80% of our anticipated oil production for the last six months of 2008;
- 28% of our anticipated distillate yield for 2008;
- 24% of our anticipated heavy fuel oil yield for 2008; and
- 15% of our anticipated gasoline yield for the last six months of 2008.

The details of these contracts have been further discussed in the Price Risk Management section for each of our upstream and downstream operations. While we do not attempt to forecast either the commodity prices in our upstream operations nor the refining margins in our downstream operations, we will continue to enter into commodity price risk management contracts to mitigate price volatility with the objective of stabilizing our future cash flows to fund long term sustainable cash distributions as well as our capital spending programs through a wide variety of pricing environments.

To complement our commodity price risk management contracts, we have forward sold US $8,750,000 per month at an average Canadian to U.S. dollar exchange rate of approximately US $0.89 per Canadian dollar through December 2007 and a further US $10,000,000 per month by way of a US $1.00 – US $0.95 per Canadian dollar collar. For 2008, we have sold forward US $8,333,000 per month at US$0.90 per Canadian dollar for the first six months of the year and a further US $10,000,000 per month by way of a US $1.00 - US $0.95 per Canadian dollar collar for the entire year. This reduces our exposure to fluctuations in the Canadian/U.S. dollar exchange rate. We have also entered into contracts to fix the price of 35 megawatt hours, representing approximately 50% of our anticipated electric power consumption in our upstream operations in Alberta, through December 2008 at a price of $56.69 per megawatt hour. Our objective with these contracts is to substantially reduce the volatility of our operating costs to fluctuations in the cost of electricity which accounts for approximately 20% of the operating costs in our upstream operations.

For 2008, we are anticipating that our upstream business will produce approximately 55,000 boe/day with a capital program of $225 million. Light and medium gravity oil, including natural gas liquids, is expected to represent approximately 49% of our total production in 2008 with heavy oil and natural gas accounting for 23% and 28% respectively. Our upstream operating costs are forecasted to range between $12.50 and $13.00 per boe with power and well servicing costs accounting for 25% and 23% of the total, respectively. We will continue to evaluate acquisition opportunities as well as offer selected properties for divestment while striving to maintain or enhance our productive capability and improve our unit operating costs.

In our downstream business, we expect to achieve a throughput of 113,000 bbls/day of feedstock with no planned maintenance shutdowns in 2008. We are also anticipating a 10% improvement in the combined gasoline/distillate yield to 72% along with a 50% reduction in purchased vacuum gas oil as a result of improved crude unit and vacuum tower operating performance. The operating costs of the refinery, excluding the cost of purchased energy, are expect to remain unchanged at $85 million (or $2.06 per barrel) with a capital spending plan of $63 million.

The following table reflects the sensitivity of our 2008 operations to changes in the following key factors to our business:

	Assumption	Change	Impact on Cash Flow
WTI oil price (US$/bbl)	$ 80.00	$ 5.00	$ 0.18 / Unit
CAD/USD exchange rate	$ 1.00	$ 0.05	$ 0.36 / Unit
AECO daily natural gas price	$ 6.50	$ 1.00	$ 0.19 / Unit
Refinery crack spread (US$/bbl)	$ 10.00	$ 1.00	$ 0.27 / Unit
Operating Expenses (per boe)	$ 12.50	$ 1.00	$ 0.14 / Unit

In addition to focusing property acquisition strategy on properties adjacent to our existing upstream operations, 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 three 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 table and discussion below highlight our third quarter 2007 performance over the preceding seven quarters on select measures:

	2007			2006				2005
(000s except where noted)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenue, net of royalties	**$ 1,007,786**	$1,133,450	$ 1,025,512	$ 682,744	$ 259,818	$ 257,103	$ 181,160	$ 154,646
Net income (loss)	**$ 11,811**	$ 6,248	$ 69,850	$ 1,533	$ 107,768	$ 60,682	$ (33,937)	$ 75,638
Per trust unit, basic[1]	**$ 0.08**	$ 0.05	$ 0.55	$ 0.01	$ 1.01	$ 0.60	$ (0.41)	$ 1.45
Per trust unit, diluted[1]	**$ 0.08**	$ 0.05	$ 0.55	$ 0.01	$ 0.99	$ 0.60	$ (0.41)	$ 1.42
Cash from operating activities	**$ 191,049**	$ 251,218	$ 111,048	$ 140,543	$ 143,597	$ 135,581	$ 88,164	$ 97,967
Per trust unit, basic	**$ 1.31**	$ 1.88	$ 0.87	$ 1.21	$ 1.35	$ 1.34	$ 1.07	$ 1.87
Per trust unit, diluted	**$ 1.22**	$ 1.67	$ 0.84	$ 1.16	$ 1.31	$ 1.30	$ 1.07	$ 1.83
Distributions per Unit, declared	**$ 1.14**	$ 1.14	$ 1.14	$ 1.14	$ 1.14	$ 1.14	$ 1.11	$ 1.05
Total long term financial liabilities	**$ 2,072,870**	$1,961,748	$ 2,409,241	$ 2,488,524	$ 1,105,728	$ 746,840	$ 735,896	$ 349,074
Total assets	**$ 5,585,651**	$5,613,333	$ 5,800,346	$ 5,745,558	$ 4,076,771	$ 3,455,918	$ 3,470,653	$1,308,481

(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 have generally increased steadily over the eight quarters with significantly higher revenue in the Second and Third Quarters of 2006 over the preceding quarters due to the incremental revenue from the Viking acquisition in February 2006 along with stronger commodity prices including narrowing crude oil differentials. In the Fourth Quarter of 2006, the significant increase in revenue over the prior quarter is attributed to the North Atlantic acquisition which is a margin business with significant revenues coupled with significant costs for crude oil feedstock. In the Third Quarter of 2007 net revenues decreased from the two preceding quarters due to the Refinery's lower realized prices and decreased throughput due to a planned shutdown. The growth in cash from operating activities is closely aligned with the growth in net revenues and is attributed to the same factors as the growth in net revenues, reflecting the cyclical nature of the downstream segment in the three quarters of 2007.

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. Additionally, the volatility in net income (loss) between quarters in 2005 and 2006 is due to the changes in the fair value of our risk management contracts and this is the primary reason why our net income (loss) does not reflect the same trends as net revenues or cash from operating activities.

Growth in total assets over the last eight quarters is directly attributed to our acquisition of Viking in the first quarter of 2006, Birchill in the Third Quarter of 2006 and North Atlantic in the Fourth Quarter of 2006. The changes in our total long term financial liabilities is primarily due to the impact of our acquisitions, offset by our issuance of trust units and the net cash surplus of cash from operating activities over our 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 take place and when these activities are reported. Changes in these estimates could have a material impact on our reported results.

Reserves

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

- Expected reservoir characteristics based on geological, geophysical and engineering assessments;
- Future production rates based on historical performance and expected future operating and investment activities;
- Future oil and gas prices and quality differentials; and
- Future development costs.

We follow the full cost method of accounting for our oil and natural gas activities. All costs of acquiring oil and natural gas properties and related exploration and development costs, including overhead charges directly related to these activities, are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against income, and renewals and enhancements that extend the economic life of the capital assets are capitalized. The provision for depletion and depreciation of petroleum and natural gas assets is calculated on the unit-of-production method, based on proved reserves as estimated by independent petroleum engineers.

Reserve estimates impact net income through depletion, the determination of asset retirement obligations and the application of an impairment test. Revisions or changes in the reserve estimates can have either a positive or a negative impact on net income, capital assets and asset retirement obligations.

Asset Retirement Obligations

In the determination of our asset retirement obligations, management is required to make a significant number of estimates with respect to activities that will occur in many years to come. In arriving at the recorded amount of the asset retirement obligation numerous assumptions are made with respect to ultimate settlement amounts, inflation factors, credit adjusted risk free discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligation also results in an increase to the carrying cost of capital assets. The obligation accretes to a higher amount with the passage of time as it is determined using discounted present values. A change in any one of the assumptions could impact the estimated future obligation and in return, net income. It is difficult to determine the impact of a change in any one of our assumptions. As a result, a reasonable sensitivity analysis cannot be performed.

Impairment of Capital Assets

In determining if the capital assets are impaired there are numerous estimates and judgments involved with respect to our estimates. The two most significant assumptions in determining cash flows are future prices and reserves.

The estimates of future prices require significant judgments about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility. The prices used in carrying out our impairment test are based on prices derived from a consensus of future price forecasts among industry analysts. Given the significant assumptions required and the possibility that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate.

If forecast WTI crude oil prices were to fall by 18% to 20%, the initial assessment of impairment indicators would not change; however, below that level, we would likely experience an impairment. Although oil and natural gas prices fluctuate a great deal in the short-term, they are typically stable over a longer time horizon. This mitigates potential for impairment.

Reductions in estimated future prices may also have an impact on estimates of economically recoverable proved reserves.

Any impairment charges would reduce our net income.

It is difficult to determine and assess the impact of a decrease in our proved reserves on our impairment tests. The relationship between the reserve estimate and the estimated undiscounted cash flows is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment.

Employee Future Benefits

We maintain a defined benefit pension plan for the employees of North Atlantic. Obligations under employee future benefit plans are recorded net of plan assets where applicable. An independent actuary determines the costs of our employee future benefit programs using the projected benefit method. The determination of these costs requires management to estimate or make assumptions regarding the expected plan investment performance, salary escalation, retirement ages of employees, expected health care costs, employee turnover, discount rates and return on plan assets. The obligation and expense recorded related to our employee future benefit plans could increase or decrease if there were to be a change in these estimates. Pension expense represented less than 0.5% of our total expenses for 2006.

Purchase Price Allocations

Business acquisitions are accounted for by the purchase method of accounting. Under this method, the purchase price is allocated to the assets acquired and the liabilities assumed based on the fair values at the time of the acquisitions. The excess of the purchase price over the assigned fair values of the identifiable assets and liabilities is allocated to goodwill. In determining the fair value of the assets and liabilities we are often required to make assumptions and estimates about future events, such as future oil and gas prices, crack spreads and discount rates. Changes in any of these assumptions would impact amounts assigned to assets and liabilities and goodwill in the purchase price allocation and as a result, future net earnings.

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

Convergence of Canadian GAAP with International Financial Reporting Standards

In 2006, Canada's Accounting Standards Board ("AcSB") ratified a strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards ("IFRS") over a transitional period. In early 2007, the AcSB issued a decision summary with respect to its progress on the implementation strategy of IFRS for publicly accountable enterprises and will confirm a changeover date from Canadian GAAP to IFRS in March of 2008. Currently, it is expected that the transition date will be January 1, 2011. This convergence initiative is in its early stages as of the date of these financial statements and we have the option to adopt U.S. GAAP at any time prior to the expected conversion date. We are currently evaluating our options with respect to this change and accordingly it is premature to assess the impact of the initiative, if any, on our financial statements at this time.

Financial Instruments – Disclosures and Presentation

On December 1, 2006, the AcSB issued the following two new standards regarding the disclosure and presentation of financial instruments with an implementation date for annual and interim financial statements beginning on or after October 1, 2007.

- Section 3862 – *Financial Instruments – Disclosures*

  This standard requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks.

- Section 3863 – *Financial Instruments – Presentation*

  This standard establishes standards for presentation of financial instruments and non-financial derivatives and deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset.

Also on December 1, 2006, the AcSB issued a new standard regarding Capital Disclosure requiring 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. This standard also has an implementation date for annual and interim financial statements beginning on or after October 1, 2007.

In June 2007, the AcSB issued section 3031, Inventories, which replaces the existing inventories standard. This new standard requires 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. This standard is to be adopted for fiscal years beginning on or after January 1, 2008. We do not expect the adoption of this section to have a material impact on our net income or financial position.

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:

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 (including the Supply and Offtake Agreement with Vitol Refining S.A.) 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
- Selectively adding experienced refining management to further strengthen our "in-house" management team.

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

The Government of Alberta announced its intention to examine Alberta's royalty and tax regime and in February 2007, appointed an independent panel of experts to conduct a review of all aspects of the royalty system including conventional oil and gas, oil sands and coalbed methane. On September 18, 2007, the independent panel published its report and on October 25, 2007, the Government of Alberta released its New Royalty Framework outlining changes that effective January 1, 2009 will increase the royalty rates using a price-sensitive and volume-sensitive sliding rate formula for both conventional oil and natural gas. While there are considerable details to be provided, our preliminary assessment is that the impact of the changes on Harvest will be modest, as many of our oil and natural gas wells will be considered low productivity wells that continue to attract favourable royalty treatment. Based on the information available and assuming royalties will continue to be based on field gate prices realized by producers, our analysis indicates that if our field gate prices are less than $53.00, our oil royalties will be lower and if prices are higher, our royalties will increase and similarly for natural gas, if our gas plant prices are less than $7.00, our royalties will be lower and if prices are higher, our royalties will increase. Of particular concern is the royalty rates on natural gas where production from recently drilled wells may qualify as high productivity for a period of time and attract a royalty that is 15% to 20% higher than under the current royalty regime and this could significantly penalize the economics of our drilling and natural gas wells. Generally, we will pay higher royalties if commodity prices are high and lower royalties as most of our wells will be considered to be low productivity wells.

In 2002, the Government of Canada ratified the Kyoto Protocol which calls for Canada to reduce its greenhouse gas emissions to specified levels. On April 26, 2007, the Government of Canada released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan") which includes a regulatory framework for air emissions. This Action Plan is to regulate the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. Meanwhile, the Government of Alberta has introduced the Climate Change and Emissions Management Amendment Act which intends to reduce greenhouse gas emissions intensity from large emitting facilities. Giving the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to assess the impact of the requirements on our operations and financial performance.

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 and operating expenses, net of any realized gains and losses on related risk management contracts. 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.

FORWARD-LOOKING INFORMATION

This MD&A highlights significant business results and statistics from our consolidated financial statements for the three and nine months ended September 30, 2007 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 refinery 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, 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.

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, 2007		December 31, 2006
Assets				
Current assets				
Cash	$	**-**	$	10,006
Accounts receivable and other		**245,729**		257,131
Fair value of risk management contracts *[Note 16]*		**22,164**		17,914
Prepaid expenses and deposits		**12,279**		12,713
Inventories *[Note 4]*		**64,393**		30,512
		344,565		328,276
Deferred charges and other non-current assets *[Note 7]*		**-**		25,067
Fair value of risk management contracts *[Note 16]*		**-**		9,843
Property, plant and equipment *[Note 5]*		**4,287,513**		4,393,832
Intangible assets *[Note 6]*		**97,580**		122,362
Goodwill		**855,993**		866,178
	$	**5,585,651**	$	5,745,558
Liabilities and Unitholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities *[Note 8]*	**$**	**297,178**	$	294,582
Cash distribution payable		**55,648**		46,397
Current portion of convertible debentures *[Note 11]*		**24,317**		-
Fair value deficiency of risk management contracts *[Note 16]*		**46,614**		26,764
		423,757		367,743
Bank loan *[Note 10]*		**1,205,119**		1,595,663
$7^{7/8}$% Senior Notes		**241,628**		291,350
Convertible debentures *[Note 11]*		**626,123**		601,511
Fair value deficiency of risk management contracts *[Note 16]*		**2,484**		2,885
Asset retirement obligation *[Note 9]*		**216,664**		202,480
Employee future benefits *[Note 15]*		**12,215**		12,227
Deferred credit		**653**		794
Future income tax *[Note 14]*		**144,170**		-
Unitholders' equity				
Unitholders' capital *[Note 12]*		**3,692,308**		3,046,876
Equity component of convertible debentures		**39,538**		36,070
Accumulated income		**360,450**		271,155
Accumulated distributions		**(1,195,667)**		(730,069)
Accumulated other comprehensive (loss) income *[Note 2]*		**(183,791)**		46,873
		2,712,838		2,670,905
	$	**5,585,651**	$	5,745,558

Commitments, contingencies and guarantees *[Note 19]*
Subsequent events *[Note 20]*
See accompanying notes to these consolidated financial statements.

Approved by the Board of Directors:

((signed))
Hector J. McFadyen
Director

((signed))
Verne G. Johnson
Director

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE (LOSS) INCOME (UNAUDITED)
(thousands of Canadian dollars, except per Trust Unit amounts)

	Three Months Ended Sept 30, 2007	Three Months Ended Sept 30, 2006	**Nine Months Ended Sept 30, 2007**	Nine Months Ended Sept 30, 2006
Revenue				
Petroleum, natural gas, and refined product sales	**$ 1,088,320**	$ 314,180	**$ 3,350,479**	$ 847,465
Royalty expense	**(56,806)**	(54,362)	**(160,003)**	(149,384)
Risk management contracts				
Realized net losses	**(1,793)**	(24,032)	**(8,916)**	(56,623)
Unrealized net gains (losses)	**(21,935)**	77,078	**(25,042)**	35,966
	1,007,786	312,864	**3,156,518**	677,424
Expenses				
Purchased products for processing and resale	**747,010**	-	**2,087,948**	-
Operating	**133,926**	62,489	**372,837**	173,176
Transportation and marketing	**14,085**	3,535	**36,674**	9,223
General and administrative *[Note 13]*	**4,681**	7,500	**31,548**	21,825
Transaction charges	**-**	-	**-**	12,072
Interest and financing charges on short term debt	**606**	-	**4,986**	-
Interest and financing charges on long term debt	**35,764**	16,685	**115,840**	42,573
Depletion, depreciation, amortization and accretion	**130,396**	115,223	**393,819**	297,726
Foreign exchange (gain) loss	**(16,102)**	163	**(98,460)**	(11,327)
Large corporations tax and other tax	**(39)**	(499)	**85**	8
Future income tax expense (recovery) *[Note 14]*	**(54,352)**	-	**123,332**	(2,300)
Non-controlling interest	**-**	-	**-**	(65)
	995,975	205,096	**3,068,609**	542,911
Net income for the period	**11,811**	107,768	**87,909**	134,513
Cumulative Translation Adjustment	**(86,033)**	-	**(230,664)**	-
Comprehensive (loss) income for the period *[Note 2]*	**$ (74,222)**	$ 107,768	**$ (142,755)**	$ 134,513
Net income per Trust Unit, basic *[Note 12]*	**$ 0.08**	$ 1.01	**$ 0.65**	$ 1.39
Net income per Trust Unit, diluted *[Note 12]*	**$ 0.08**	$ 0.99	**$ 0.65**	$ 1.38

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	Accumulated Income	Accumulated Distributions	Accumulated Other Comprehensive (Loss) Income *[Note 2]*	Total
At December 31, 2005	**$ 747,312**	**$ 2,639**	**$ 135,665**	**$ (261,282)**	**$ -**	**$ 624,334**
Issued in exchange for assets of Viking	1,638,131	-	-	-	-	1,638,131
Issued for cash						
August 17, 2006	230,118	-	-	-	-	230,118
Equity component of convertible debenture issuances						
10.5% Debentures Due 2008	-	9,301	-	-	-	9,301
6.40% Debentures Due 2012	-	14,822	-	-	-	14,822
Convertible debenture conversions						
9% Debentures Due 2009	398	-	-	-	-	398
8% Debentures Due 2009	1,077	(8)	-	-	-	1,069
6.5% Debentures Due 2010	3,562	(223)	-	-	-	3,339
10.5% Debentures Due 2008	9,570	(1,990)	-	-	-	7,580
6.40% Debentures Due 2012	21	(2)	-	-	-	19
Exchangeable share retraction	2,648	-	(556)	-	-	2,092
Exercise of unit appreciation rights and other	11,912	-	-	-	-	11,912
Issue costs	(12,838)	-	-	-	-	(12,838)
Net income	-	-	134,513	-	-	134,513
Distributions and distribution reinvestment plan	125,470	-	-	(333,813)	-	(208,343)
At September 30, 2006	**$ 2,757,381**	**$ 24,539**	**$ 269,622**	**$ (595,095)**	**$ -**	**$ 2,456,447**
At December 31, 2006, as restated *[Note 2]*	**$ 3,046,876**	**$ 36,070**	**$ 271,155**	**$ (730,069)**	**$ 46,873**	**$ 2,670,905**
Adjustment arising from change in accounting policies *[Note 2]*	(49)	-	1,386	-	-	1,337
Issued for cash						
February 1, 2007	143,834	-	-	-	-	143,834
June 1, 2007	230,029	-	-	-	-	230,029
Equity component of convertible debenture issuances						
7.25% Debentures Due 2014	-	13,100	-	-	-	13,100
Convertible debenture conversions						
9% Debentures Due 2009	220	-	-	-	-	220
8% Debentures Due 2009	456	(3)	-	-	-	453
6.5% Debentures Due 2010	882	(55)	-	-	-	827
10.5% Debentures Due 2008	2,999	(627)	-	-	-	2,372
6.40% Debentures Due 2012	122	(10)	-	-	-	112
7.25% Debentures Due 2013	244	(8)	-	-	-	236
7.25% Debentures Due 2014	157,139	(8,929)	-	-	-	148,210
Exercise of unit appreciation rights and other	400	-	-	-	-	400
Issue costs	(26,258)	-	-	-	-	(26,258)
Foreign currency translation adjustment	-	-	-	-	(230,664)	(230,664)
Net income	-	-	87,909	-	-	87,909
Distributions and distribution reinvestment plan	135,414	-	-	(465,598)	-	(330,184)
At September 30, 2007	**$ 3,692,308**	**$ 39,538**	**$ 360,450**	**$ (1,195,667)**	**$ (183,791)**	**$ 2,712,838**

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(thousands of Canadian dollars)

	Three Months Ended Sept 30, 2007	Three Months Ended Sept 30, 2006	**Nine Months Ended Sept 30, 2007**	Nine Months Ended Sept 30, 2006
Cash provided by (used in)				
Operating Activities				
Net income for the period	**$ 11,811**	$ 107,768	**$ 87,909**	$134,513
Items not requiring cash				
Depletion, depreciation, amortization and accretion	**130,396**	115,223	**393,819**	297,726
Unrealized foreign exchange (gain) loss	**29,463**	834	**(49,559)**	(10,289)
Non-cash interest expense and amortization of finance charges	**2,457**	1,095	**9,590**	3,972
Unrealized loss (gain) on risk management contracts *[Note 16]*	**21,935**	(77,078)	**25,042**	(35,966)
Future income tax expense (recovery) *[Note 14]*	**(54,352)**	-	**123,332**	(2,300)
Non-controlling interest	**-**	-	**-**	(65)
Unit based compensation expense	**(4,415)**	(816)	**4,462**	1,725
Amortization of office lease premium and deferred rent expense	**21**	(71)	**27**	(122)
Employee benefit obligation	**(1,108)**	-	**(12)**	-
Settlement of asset retirement obligations *[Note 9]*	**(2,902)**	(2,285)	**(7,290)**	(4,028)
Change in non-cash working capital *[Note 18]*	**57,743**	(1,073)	**(34,005)**	(17,824)
	191,049	143,597	**553,315**	367,342
Financing Activities				
Issue of Trust Units, net of issue costs	**(553)**	217,950	**354,004**	217,849
Issue of convertible debentures, net of issue costs *[Note 11]*	**-**	-	**220,489**	-
Redemption of exchangeable shares	**-**	-	**-**	(1,022)
Bank borrowings, net *[Note 10]*	**126,015**	363,644	**(366,355)**	471,072
Financing costs	**-**	(54)	**(273)**	(1,183)
Cash distributions	**(117,485)**	(73,566)	**(320,933)**	(184,734)
Change in non-cash working capital *[Note 18]*	**(2,050)**	7,879	**9,413**	(10,891)
	5,927	515,853	**(103,655)**	491,091
Investing Activities				
Additions to property, plant and equipment	**(85,791)**	(129,054)	**(297,253)**	(286,523)
Business acquisitions	**(140,518)**	(563,561)	**(170,782)**	(563,561)
Property acquisitions	**(4,017)**	(312)	**(15,103)**	(23,984)
Property dispositions	**5,157**	-	**37,355**	-
Change in non-cash working capital *[Note 18]*	**15,096**	33,477	**(14,382)**	15,635
	(210,073)	(659,450)	**(460,165)**	(858,433)
Change in cash and cash equivalents	**$ (13,097)**	$ -	**$ (10,505)**	$ -
Effect of exchange rate changes on cash	**(350)**	-	**499**	-
Cash and cash equivalents, beginning of period	**13,447**	-	**10,006**	-
Cash and cash equivalents, end of period	**$ -**	$ -	**$ -**	$ -
Interest paid	**$ 39,560**	$ 6,304	**$ 90,421**	$23,586
Large corporation tax and other tax paid	**$ (79)**	$ 68	**$ 45**	$880

See accompanying notes to these consolidated financial statements.

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
Period ended September 30, 2007
(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. Except as noted below, 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, 2006 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. Changes in Accounting Policies

Financial Instruments and Comprehensive Income
Effective January 1, 2007, Harvest adopted three new and revised Canadian accounting standards as issued by the Canadian Institute of Chartered Accountants respecting "Financial Instruments – Recognition and Measurement", "Financial Instruments – Presentation and Disclosure" and "Comprehensive Income".

Financial Instruments

The revised standard on financial instruments provides new guidance on how to recognize and measure financial instruments. It requires all financial instruments to be recorded at fair value when initially recognized. Subsequent measurement is either at fair value or amortized cost, depending on the classification of the financial instrument. Financial assets and liabilities that are held-for-trading are measured at fair value with changes in those fair values recognized in net income. Available-for-sale financial assets are measured at fair value with unrealized gains or losses recognized in other comprehensive income. Held-to-maturity assets, loans and receivables and other liabilities are all measured at amortized cost with any related expenses or income recognized in net income. Price risk management contracts are classified as held-for-trading and are measured at fair value at initial recognition and at subsequent measurement dates. Any derivatives embedded in other financial or non-financial contracts that were entered into on or after January 1, 2001 must also be measured at fair value and recorded in the financial statements if the embedded derivative is not closely related to the host contract. Fair value of financial instruments is based on market prices where available, otherwise it is calculated as the net present value of expected future cash flows. For those items measured at amortized cost, interest expense is calculated using an effective interest rate that accretes any discount or premium over the life of the instrument so that the carrying value equals the face value at maturity.

Harvest does not have any financial assets classified as available-for-sale or held-to-maturity. The only items on Harvest's balance sheet that are classified as held-for-trading and subsequently measured at fair value are cash and our price risk management contracts. The remainder of the financial instruments are measured at amortized cost. As well, there are no significant embedded derivatives that need to be recorded in the financial statements.

Transaction costs relating to financial instruments classified as held for trading are expensed in net income in the period that they are incurred. Harvest has elected to add all other transaction costs that are directly attributable to the acquisition or issue of a financial asset or liability to the amount of the financial asset or liability that is recorded on initial recognition.

The transitional provisions of the financial instruments standard require retrospective adoption without restatement of prior period financial statements. The provisions also require all financial instruments to be remeasured using the criteria of the new standard and any change in the previous carrying amount to be recognized as an adjustment to retained earnings on January 1, 2007. As our price risk management contracts were already measured at fair value, the most significant change for Harvest was reclassifying the deferred charges relating to our senior notes and convertible debentures and netting these amounts against the respective liability. These charges are then amortized to income using an effective interest rate. The effect of applying this new standard on January 1, 2007 was to reduce the carrying value of the following accounts as indicated with an offsetting reduction to deferred charges:

Deferred charges	$	(25,067)
7 7/8% Senior notes		(9,522)
Convertible debentures		(16,882)
Unitholders' capital		(49)
Accumulated income		1,386

See Note 16 for the additional presentation and disclosure requirements for Financial Instruments.

Other Comprehensive Income

The new standards introduce the concept of comprehensive income, which consists of net income and other comprehensive income. Other comprehensive income represents changes in Unitholders' equity during a period arising from transactions and other events with non-owner sources. The transitional provisions of this section require that the comparative statements are restated to reflect the application of this standard only on certain items.

For Harvest, the only such item is the unrealized foreign currency translation gains or losses arising from our downstream operations, which is considered a self-sustaining operation with a U.S. dollar functional currency. As the cumulative translation adjustment was presented as a separate component of Unitholders' equity already, this restatement simply required the cumulative translation adjustment to be reclassified to accumulated other comprehensive income on the balance sheet and statement of Unitholders' equity.

Future Accounting Changes
New accounting standards were issued on December 1, 2006 that effective January 1, 2008 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. New capital disclosures are also required effective January 1, 2008 on 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.

3. Business Acquisition

(a) Grand Petroleum Inc. ("Grand")
Pursuant to its cash offer of $3.84 for each issued and outstanding common share of Grand, Harvest acquired control of Grand with its acquisition of 21,310,419 Grand common shares for cash consideration of $81.8 million on July 26, 2007. Subsequent to this acquisition of 74.6% of the issued and outstanding common shares of Grand, Harvest acquired the remaining 7,251,604 common shares of Grand for an additional $27.8 million by extending its offer to purchase to August 9, 2007 and thereafter pursuant to the compulsory acquisition provisions of the *Business Corporations Act (Alberta)*. The aggregate consideration for the Grand acquisition consists of the following:

		Amount
Cash paid	$	109,678
Assumption of bank debt		28,798
Acquisition costs		785
	$	139,261

This acquisition has been accounted for using the purchase method, whereby the assets acquired and the liabilities assumed are recorded at their fair values with the excess of the aggregate consideration over the fair value of the identifiable net assets allocated to goodwill. As of the acquisition date, Grand's operating results have been included in Harvest's revenues, expenses and capital spending. The following summarizes the allocation of the aggregate consideration for the Grand acquisition.

		Amount
Net working capital	$	(3,451)
Property, plant and equipment		147,420
Goodwill		20,546
Asset retirement obligation		(4,416)
Future income tax		(20,838)
	$	139,261

(b) Private petroleum and natural gas corporation
On March 1, 2007, Harvest acquired all of the issued and outstanding shares of a private petroleum and natural gas corporation for $30.6 million net of working capital adjustments and transaction costs. The results of operations of this acquisition have been included in the consolidated financial statements since its acquisition date. An officer of Harvest was a director of this private corporation and received proceeds that are considered to be insignificant to both the officer and Harvest.

4. Inventories

	September 30, 2007	December 31, 2006
Petroleum products	$ 54,522	$ 19,513
Parts and supplies	9,871	10,999
Total inventories, net	$ 64,393	$ 30,512

5. Property, Plant and Equipment

	September 30, 2007			December 31, 2006
	Upstream	Downstream	Total	Total
Cost	$ 4,230,426	$ 1,146,661	$ 5,377,087	$ 5,115,032
Accumulated depletion and depreciation	(1,032,039)	(57,535)	(1,089,574)	(721,200)
Net book value	$ 3,198,387	$ 1,089,126	$ 4,287,513	$ 4,393,832

General and administrative costs of $1.8 million have been capitalized during the three month period ended September 30, 2007 (three months ended September 30, 2006 – $2.4 million), which included a recovery of $1.0 million (three months ended September 30, 2006 - $0.1 million expense) related to the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan. For the nine month period ended September 30, 2007, $8.4 million (nine months ended September 30, 2006 – $9.2 million) of general and administrative costs have been capitalized, of which $1.3 million (nine months ended September 30, 2006 – $2.9 million) relate to the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan.

6. Intangible Assets

	September 30, 2007			December 31, 2006
	Cost	Accumulated Amortization	Net Book value	Net Book value
Engineering drawings	$ 88,537	$ 4,242	$ 84,295	$ 102,641
Marketing contracts	6,157	849	5,308	7,109
Customer lists	3,728	357	3,371	4,276
Fair value of office lease	931	372	559	726
Financing costs	12,113	8,066	4,047	7,610
Total	$ 111,466	$ 13,886	$ 97,580	$ 122,362

7. Other Non-Current Assets

	September 30, 2007	December 31, 2006
Deferred charges, net of amortization *[Note 2]*	$ -	$ 23,659
Discount on senior notes, net of amortization *[Note 2]*	-	1,408
Total	$ -	$ 25,067

8. Accounts Payable and Accrued Liabilities

	September 30, 2007	December 31, 2006
Trade accounts payable	$ 138,011	$ 111,837
Accrued interest	15,162	14,367
Trust Unit Incentive Plan and Unit Award Incentive Plan *[Note 13]*	11,675	6,442
Other accrued liabilities	132,330	161,936
Total	$ 297,178	$ 294,582

9. Asset Retirement Obligation

Harvest's asset retirement obligations result from its net ownership interest in petroleum and natural gas assets including well sites, gathering systems and processing facilities and the estimated costs and timing to reclaim and abandon them. Harvest estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations to be approximately $711.3 million which will be incurred between 2007 and 2055. The majority of the costs will be incurred between 2025 and 2035. A credit-adjusted risk-free discount rate of 10% was used to calculate the fair value of the asset retirement obligations set-up before September 30, 2005. Upward revisions and new obligations after this date are discounted using a revised credit-adjusted risk-free discount rate of 8%.

A reconciliation of the asset retirement obligations is provided below:

		September 30, 2007		December 31, 2006
Balance, beginning of period	$	**202,480**	$	110,693
Incurred on acquisition of a private corporation		**1,629**		-
Incurred on acquisition of Grand		**4,416**		-
Incurred on acquisition of Viking		**-**		60,493
Incurred on acquisition of Birchill		**-**		1,219
Liabilities incurred		**1,963**		2,763
Revision of estimates		**-**		20,544
Liabilities settled		**(7,290)**		(9,186)
Accretion expense		**13,466**		15,954
Balance, end of period	**$**	**216,664**	$	202,480

Harvest has gross asset retirement obligations of approximately $14.7 million relating to the downstream assets that are expected to be settled after 2081. Due to the long time period prior to settlement, the discounted value today is immaterial.

10. Bank Loan

On May 7, 2007, Harvest and its lenders amended the Three Year Extendible Revolving Credit Facility to increase the aggregate commitment amount from $1.4 billion to $1.6 billion and extend the maturity date of the facility from March 31, 2009 to April 30, 2010 with respect to $1,535 million of the aggregate commitment amount. Effective May 7, 2007, the Three Year Extendible Revolving Credit Facility consists of $1,535 million of commitments with a maturity date of April 30, 2010 and $65 million of commitments with a maturity date of March 31, 2009.

On October 1, 2007, two of Harvest's existing lenders agreed to assume $50 million of the $65 million commitment to mature on March 31, 2009 and concurrently extended the maturity to April 30, 2010. On November 1, 2007, another of Harvest's existing lenders agreed to assume the remaining $15 million of credit commitments to mature on March 31, 2009 and similarly extended the maturity to April 30, 2010. Subsequent to these reassignments, the entire $1.6 billion of Harvest's Three Year Extendible Revolving Credit Facility matures on April 30, 2010.

11. Convertible Debentures

Harvest has 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, 2006.

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

Series	Conversion price / Trust Unit	Maturity	First redemption period	Second redemption period
9% Debenture Due 2009	$ 13.85	May 31, 2009	Jun. 1/07-May 31/08	Jun. 1/08-May. 30/09
8% Debenture Due 2009	$ 16.07	Sept. 30, 2009	Oct. 1/07-Sept. 30/08	Oct. 1/08-Sept. 29/09
6.5% Debenture Due 2010	$ 31.00	Dec. 31, 2010	Jan. 1/09-Dec. 31/09	Jan. 1/10-Dec. 30/10
10.5% Debenture Due 2008	$ 29.00	Jan. 31, 2008	Feb. 1/06-Jan. 31/07	Feb. 1/07-Jan. 30/08
6.40% Debenture Due 2012[(1)]	$ 46.00	Oct. 31, 2012	Nov. 1/08-Oct. 31/09	Nov. 1/09-Oct. 31/10
7.25% Debenture Due 2013[(1)]	$ 32.20	Sept. 30, 2013	Oct. 1/09-Sept. 30/10	Oct. 1/10-Sept. 30/11
7.25% Debenture Due 2014[(1)]	$ 27.25	Feb. 28, 2014	Mar. 1/10-Feb. 28/11	Mar. 1/11-Feb. 29/12

[(1)] These series of convertible debentures may also be redeemed by Harvest at a price of $1,000 per debenture after the second redemption period until maturity.

The following table summarizes the face value, carrying amount and fair value of the convertible debentures:

	September 30, 2007			December 31, 2006		
	Face Value	**Carrying Amount(1)**	**Fair Value**	Face Value	Carrying Amount(1)	Fair Value
9% Debentures Due 2009	**$ 1,006**	**$ 989**	**$ 2,395**	$ 1,226	$ 1,226	$ 2,280
8% Debentures Due 2009	**1,784**	**1,742**	**3,479**	2,239	2,229	3,731
6.5% Debentures Due 2010	**37,062**	**34,479**	**37,062**	37,929	35,988	37,925
10.5% Debentures Due 2008	**24,258**	**24,317**	**24,530**	26,621	26,824	28,085
6.40% Debentures Due 2012	**174,626**	**168,053**	**164,148**	174,743	167,401	159,485
7.25% Debentures Due 2013	**379,256**	**354,339**	**369,775**	379,500	367,843	375,705
7.25% Debentures Due 2014	**73,222**	**66,521**	**74,686**	-	-	-
	$ 691,214	**$ 650,440**	**$ 676,075**	$ 622,258	$ 601,511	$ 607,211

(1)Excluding the equity component.

12. Unitholders' Capital

(a) Authorized

The authorized capital consists of an unlimited number of Ordinary Trust Units, Special Trust Units and Special Voting Units. There are no Special Trust Units or Special Voting Units outstanding at September 30, 2007; therefore, unless otherwise noted, all references to Trust Units are deemed to be references to Ordinary Trust Units.

(b) Number of Units Issued

	Nine months ended September 30, 2007	Nine months ended September 30, 2006
Outstanding, beginning of period	**122,096,172**	52,982,567
Issued in exchange for assets of Viking	**-**	46,040,788
Issued for cash		
August 17, 2006	**-**	7,026,500
February 1, 2007	**6,146,750**	-
June 1, 2007	**7,302,500**	-
Convertible debenture conversions		
9% Debentures Due 2009	**15,881**	28,732
8% Debentures Due 2009	**28,307**	66,883
6.5% Debentures Due 2010	**27,967**	114,313
10.5% Debentures Due 2008	**81,478**	256,104
6.40% Debentures Due 2012	**2,542**	434
7.25% Debentures Due 2013	**7,574**	-
7.25% Debentures Due 2014	**5,753,310**	-
Exchangeable share retraction	**-**	184,809
Distribution reinvestment plan issuance	**4,969,051**	3,907,825
Exercise of unit appreciation rights and other	**10,801**	347,715
Outstanding, end of period	**146,442,333**	110,956,670

(c) Per Trust Unit Information

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

Net income adjustments		**Three months ended Sept 30, 2007**		Three months ended Sept 30, 2006		**Nine months ended Sept 30, 2007**		Nine months ended Sept 30, 2006
Net income, basic	**$**	**11,811**	$	107,768	**$**	**87,909**	$	134,513
Non-controlling interest		**-**		-		**-**		(65)
Interest on convertible debentures		**-**		4,674		**-**		292
Net income, diluted(1)	**$**	**11,811**	$	112,442	**$**	**87,909**	$	134,740

Weighted average Trust Units adjustments	**Three months ended Sept 30, 2007**	Three months ended Sept 30, 2006	**Nine months ended Sept 30, 2007**	Nine months ended Sept 30, 2006
Number of Units				
Weighted average Trust Units outstanding, basic	**145,290,946**	106,390,853	**135,431,845**	96,797,055
Effect of convertible debentures	**-**	6,380,559	**-**	302,484
Effect of exchangeable shares	**-**	-	**-**	42,507
Effect of Employee Unit Incentive Plans	**1,106,567**	312,605	**857,094**	289,678
Weighted average Trust Units outstanding, diluted(2)	**146,397,513**	113,084,017	**136,288,939**	97,431,724

(1) Net income, diluted excludes the impact of the conversions of certain of the convertible debentures for the three month and nine month periods ended September 30, 2007 of $13,799,000 and $45,487,000 respectively (three and nine months ended September 30, 2006 - nil and $12,301,000), as the impact would be anti-dilutive.

(2) Weighted average Trust Units outstanding, diluted for the three month and nine month periods ended September 30, 2007 does not include the unit impact of 20,743,678 and 23,701,488 respectively for certain of the convertible debentures (three and nine months ended September 30, 2006 – nil and 6,167,722), as the impact would be anti-dilutive.

13. Employee Unit Incentive Plans

Trust Unit Rights Incentive Plan

As at September 30, 2007, a total of 3,887,258 (3,788,125 – December 31, 2006) Unit Appreciation Rights were outstanding under the Trust Unit Rights Incentive Plan at an average exercise price of $26.47 ($29.14 – December 31, 2006).

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

	Nine months ended September 30, 2007			Year ended December 31, 2006		
	Unit Appreciation Rights		**Weighted Average Exercise Price**	Unit Appreciation Rights		Weighted Average Exercise Price
Outstanding beginning of period	**3,788,125**	**$**	**30.81**	1,305,143	$	19.72
Granted	**499,983**		**29.86**	3,924,300		31.92
Exercised	**(89,650)**		**22.05**	(1,039,018)		18.58
Forfeited	**(311,200)**		**30.94**	(402,300)		37.25
Outstanding before exercise price reductions	**3,887,258**		**30.89**	3,788,125		30.81
Exercise price reductions	-		**(4.42)**	-		(1.67)
Outstanding, end of period	**3,887,258**	**$**	**26.47**	3,788,125	$	29.14
Exercisable before exercise price reductions	**157,975**	**$**	**25.88**	266,125	$	24.18
Exercise price reductions	**-**		**(11.45)**	-		(5.37)
Exercisable, end of period	**157,975**	**$**	**14.43**	266,125	$	18.81

The following table summarizes information about Unit Appreciation Rights outstanding at September 30, 2007:

		Outstanding			Exercisable	
Exercise Price before price reductions	Exercise Price net of price reductions	At Sept 30, 2007	Weighted Average Exercise Price net of price reductions(1)	Remaining Contractual Life (1)	At Sept 30, 2007(2)	Weighted Average Exercise Price net of price reductions(1)
$12.19-$13.15	$1.55-$2.88	7,200	$ 2.47	1.2	7,200	$ 2.47
$13.75-$14.99	$3.67-$5.81	19,500	5.61	1.8	19,500	5.61
$18.90-$25.05	$9.80-$22.15	137,475	16.89	2.8	119,775	15.73
$26.09-$28.41	$22.60-$28.03	1,698,100	22.81	4.2	-	-
$28.59-$37.56	$21.68-$33.37	2,024,983	30.48	3.7	11,500	23.23
$12.19-$37.56	$1.55-$33.37	3,887,258	$ 26.47	3.9	157,975	$ 14.43

(1) Based on weighted average Unit Appreciation Rights outstanding.
(2) Based on vested Unit Appreciation Rights outstanding with exercise prices equal to or less than the market price.

Unit Award Incentive Plan
At September 30, 2007, 338,955 Units were outstanding under the Unit Award Incentive Plan (306,699 – December 31, 2006).

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

	Nine months ended September 30, 2007	Year ended December 31, 2006
Outstanding, beginning of period	**306,699**	35,365
Granted	**49,742**	320,905
Adjusted for distributions	**34,739**	27,879
Exercised	**(32,789)**	(41,530)
Forfeited	**(19,436)**	(35,920)
Outstanding, end of period	**338,955**	306,699

Harvest has recognized compensation recovery of $4.1 million and expense of $6.4 million for the three and nine months ended September 30, 2007 respectively ($0.5 million expense and $10.0 million expense – three and nine months ended September 30, 2006), including non cash compensation recovery of $4.5 million and expense of $4.2 million for the three and nine months ended September 30, 2007 respectively ($0.8 million recovery and $1.7 million expense – three and nine months ended September 30, 2006), 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. Recoveries occur when the Trust Unit market price decreases below the previous measurement date.

14. Income Taxes

On June 22, 2007, Bill C-52 Budget Implementation Act, 2007 received Royal Assent which contains legislation to apply a 31.5% tax to distributions from Canadian publicly traded income trusts. The new tax is not expected to apply to Harvest until 2011 as a transition period has been established for publicly traded trusts that existed prior to November 1, 2006. In the three and nine months ended September 30 2007, we have recorded a future income tax recovery of $54.4 million and a future income tax expense of $123.3 million respectively. Our future income tax liability represents the taxable temporary differences of the Trust, tax-effected at 31.5%, which is the rate that will be applicable in 2011 pursuant to the current legislation and Harvest's current structure.

15. 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, 2007, respectively.

Defined Benefit Plans

The measurement of the accrued benefit obligation and annual expense for the defined benefit plans requires actuarial calculations and several assumptions. These assumptions, set annually on December 31, are as follows:

	September 30, 2007		December 31, 2006	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Discount rate	**5.0%**	**5.0%**	5.0%	5.0 %
Expected long-term rate of return on plan assets	**7.0%**	**-**	7.0%	-
Rate of compensation increase	**3.5%**	**-**	3.5%	-
Employee contribution of pensionable income	**6.0%**	**-**	6.0%	-
Annual rate of increase in covered health care benefits	**-**	**11%**	-	12 %
Expected average remaining service lifetime (years)	**11.7**	**10.8**	11.7	11.1

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

	September 30, 2007	December 31, 2006
Bonds/fixed income securities	**32%**	32%
Equity securities	**68%**	68%

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

The defined benefit pension plans were subject to an actuarial valuation on December 31, 2005 and the next valuation report is due no later than December 31, 2008. The post-retirement health care benefits plan was last subject to an actuarial valuation on December 31, 2006.

	Nine Months ended September 30, 2007		Year ended December 31, 2006	
	Pension Plans	**Other Benefit Plans**	Pension Plans	Other Benefit Plans
Employee benefit obligation, beginning of period	**$ 43,101**	**$ 6,027**	$ 38,754	$ 5,315
Current service costs	**2,282**	**276**	648	88
Interest	**1,780**	**237**	546	74
Actuarial losses	**1,223**	**38**	3,422	601
Plan amendment	**-**	**-**	-	-
Benefits paid	**(463)**	**(150)**	(269)	(51)
Employee benefit obligation, end of period	**47,923**	**6,428**	43,101	6,027
Fair value of plan assets, beginning of period	**36,576**	**-**	31,878	-
Expected return on plan assets	**2,001**	**-**	3,181	-
Employer contributions	**2,474**	**150**	1,306	51
Employee contributions	**1,223**	**-**	480	-
Benefits paid	**(463)**	**(150)**	(269)	(51)
Fair value of plan assets, end of period	**41,811**	**-**	36,576	-
Funded status	**(6,112)**	**(6,428)**	(6,525)	(6,027)
Unamortized balances:				
Net actuarial losses	**325**	**-**	325	-
Carrying amount	**$ (5,787)**	**$ (6,428)**	$ (6,200)	$ (6,027)

	September 30, 2007	December 31, 2006
Summary:		
Pension plans	**$ 5,787**	$ 6,200
Other benefit plans	**6,428**	6,027
Carrying amount	**$ 12,215**	$ 12,227

Estimated pension and other benefit contributions expected to be paid from 2007 to 2016 are summarized in the commitment table [see Note 19].

For the three and nine month periods ended September 30, 2006, Harvest had no net benefit plan expense. The table below shows the components of the net benefit plan expense:

	Three Months ended September 30, 2007		Nine months ended September 30, 2007	
	Pension Plans	**Other Benefit Plans**	**Pension Plans**	**Other Benefit Plans**
Current service cost	$ 762	$ 92	$ 2,282	$ 276
Interest costs	592	79	1,780	237
Expected return on assets	(667)	-	(2,001)	-
Net benefit plan expense	$ 687	$ 171	$ 2,061	$ 513

A 1% change in the expected health care cost trend rate would have the following annual impacts as at December 31, 2006:

	1% Increase	1% Decrease
Impact on post-retirement benefit expense	$ 2	$ (2)
Impact on projected benefit obligation	16	(22)

16. Financial Instruments and risk management contracts

Financial instruments of Harvest consist of cash, accounts receivable, long-term receivables, accounts payable and accrued liabilities, cash distribution payable, bank loan, risk management contracts, convertible debentures and senior notes. The carrying value and fair value of these financial instruments at September 30, 2007 is disclosed below by financial instrument category, as well as any related gains or losses and interest income or expense for the nine months ended September 30, 2007:

Financial Instrument	Carrying Value	Fair Value	Gains/ (Losses)	Interest Income/ (Expense)	Other Income/ (Expense)
Loans and Receivables					
Accounts receivable	242,499	242,499	-	-	-
Lease payments receivable	3,230 (1)	3,230	-	157 (2)	-
Liabilites Held for Trading					
Net fair value of risk management contracts	26,934	26,934	(33,958) (3)	-	-
Other Liabilities					
Accounts payable	297,178	297,178	-	-	-
Cash distribution payable	55,648	55,648	-	-	-
Bank loan	1,205,119	1,205,119	-	(54,176) (4)	(3,835) (4)
$7^{7/8}$% Senior Notes	241,628 (6)	241,875	-	(17,328) (5)	-
Convertible debentures	650,440	676,075	-	(45,487) (5)	-

(1) Included in accounts receivable on the balance sheet.
(2) Included in petroleum, natural gas, and refined product sales in the statement of income and comprehensive income.
(3) Included in risk management contracts - realized and unrealized gains/(losses) in the statement of income and comprehensive income.
(4) Included in interest and other financing charges on short term/long term debt in the statement of income and comprehensive income. The amortization of financing fees related to this liability is included in Amortization of deferred finance charges in the statement of cash flows.
(5) Included in Interest and other financing charges on short term/long term debt in the statement of income and comprehensive income. The non-cash interest expense relating to the accretion of premiums, discounts or transaction costs that are netted against these liabilities are included in non-cash interest in the statement of cash flows.
(6) The face value of the $7^{7/8}$% Senior Notes at September 30, 2007 is $248.7 million (U.S. $250 million).

The fair value of the lease payments receivable is the present value of expected future cash flows. The fair values of the convertible debentures and the $7^{7/8}$% Senior Notes are based on quoted market prices as at September 30, 2007. 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 there are no transaction costs associated with this and the financing costs are included in intangible assets; therefore, there is no difference between the carrying value and the fair value. Due to the short term nature of cash, 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. These balances are due from companies 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, we try to obtain a guarantee from the parent company. If this is not possible, we perform our own internal credit review based on the purchaser's past financial performance. The credit risk associated with our joint venture partners is mitigated by reviewing the credit history of partners and requiring some partners to provide cash upfront in the form of cash calls for significant capital projects. As well, most agreements have a net off provision that enables us to use the proceeds from the sale of production that would otherwise be taken in kind by the partner to net off amounts owing from the partner that are in default. Historically, the only instances of impairment or potential impairment have been when a purchaser or partner has gone bankrupt.

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 by dealing with investment grade financial institutions. We have no history of impairment with these counterparties and therefore no impairment is recorded at September 30, 2007 or 2006.

Supply and Offtake Agreement Accounts Receivable (Vitol)

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 substantially all product sales are made with Vitol. 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.

Other Accounts Receivable

Harvest does not have any significant exposure to any individual customer in its downstream operations and its policy is to manage its credit risk by dealing with only financially sound customers. Credit is extended based on an evaluation of the customer's financial condition. The carrying amount of accounts receivable reflects management's assessment of the associated credit risks.

Harvest is also exposed to credit risk from customers due to the lease payments receivable relating to our net investment in vehicle and equipment leases. As some of the counterparties to these leases are employees or distributors, any over due amounts can be deducted from wages or commissions and therefore, the credit risk is low.

(ii.) Liquidity Risk

Harvest is exposed to liquidity risk mainly due to our outstanding bank balances and $7^{7/8}$% Senior Notes with repayment requirements. This risk is mitigated by managing the maturity dates on our obligations and complying with the covenants.

(iii.) Market Risk

Harvest is exposed to three types of market risks: interest rate risk, foreign currency exchange rate risk and commodity price risk.

Interest rate risk

Harvest is exposed to interest rate risk on its bank loans as interest rates are determined in relation to floating market rates. Harvest's convertible debentures and $7^{7/8}$% Senior Notes have fixed interest rates and therefore do not create an interest rate risk. Harvest manages its exposure to interest rate risk by maintaining its debt in a combination of floating rate debt denominated in Canadian dollars and bearing interest relative to the Canadian interest rate benchmark, and fixed rate debt denominated in U.S. dollars.

In addition, Harvest manages its interest rate risk by targeting appropriate levels of debt relative to its expected cash flow from operations.

Foreign currency exchange rate risk

Harvest is exposed to the risk of changes in the Canadian/U.S. dollar exchange rate on its U.S. dollar denominated revenues and in respect of its refinery crude oil purchases and sales of refined products. In addition, Harvest's $7^{7/8}$%

Senior Notes are denominated in U.S. dollars (U.S.$250 million). Interest is payable semi-annually in U.S. dollars on the notes; therefore, any interest payable at the balance sheet date is also subject to currency exchange rate risk. 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. As well, the U.S. dollar denominated debt acts as an economic hedge to help offset the impact of exchange rate movements on commodity sales during the year and the exposure on Harvest's net investment in North Atlantic as the functional currency of the refinery is U.S. dollars.

Commodity Price Risk

Harvest uses price risk management contracts for a portion of its crude oil, natural gas and refined product sales to manage its commodity price exposure and power costs. These contracts are recorded on the balance sheet at their fair value as of the balance sheet date, with changes from the prior period's fair value 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 some expected future price of the underlying asset. Variances in expected future prices expose us to commodity price risk as they will change the gain or loss that we ultimately realize on these contracts. This risk is mitigated by continuously monitoring the effectiveness of these contracts and other risk management actions.

(b) Fair Values

At September 30, 2007, the net fair value deficiency reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $26.9 million ($1.9 million – December 31, 2006), which was included in the balance sheet as follows: Fair value of risk management contracts (current assets) $22.2 million, fair value deficiency of risk management contracts (current liabilities) $46.6 million and fair value deficiency of risk management contracts $2.5 million.

The following is a summary of Harvest's risk management contracts outstanding, along with their fair value at September 30, 2007:

Quantity	Type of Contract	Term	Average Price	Fair value
Foreign Currency Exchange Rate Risk Management				
$8,750,667/month	U.S./Cdn dollar exchange rate swap	Oct. 07 – Dec. 07	1.1228 Cdn/U.S.	$ 3,692
$8,333,333/month	U.S./Cdn dollar exchange rate swap	Jan. 08 – Jun. 08	1.1099 Cdn/U.S.	5,653
$10,000,000/month	U.S./Cdn dollar collar	Oct. 07 - Dec. 08	1.000 Cdn/U.S.- 1.055 Cdn/U.S.[(a)]	3,012
				$ 12,357
Crude Oil Price Risk Management				
20,000 bbl/d	Participating swap	Oct. 07 – Dec. 07	U.S.$58.75[(b)]	$ (13,480)
10,000 bbl/d	Participating swap	Jan. 08 – Jun. 08	U.S.$60.00[(c)]	(6,707)
5,000 bbl/d	Indexed put contract – bought put	Oct. 07 – Dec. 07	U.S.$50.00[(e)]	-
2,500 bbl/d	Indexed put contract – sold call	Oct. 07 – Dec. 07	U.S.$50.00[(e)]	(6,860)
2,500 bbl/d	Indexed put contract – bought call	Oct. 07 – Dec. 07	U.S.$60.00[(e)]	4,596
2,500 bbl/d	Indexed put contract – sold call	Oct. 07 – Dec. 07	U.S.$70.00[(e)]	(2,398)
2,500 bbl/d	Indexed put contract – bought call	Oct. 07 – Dec. 07	U.S.$83.00[(e)]	356
				$ (24,493)
Natural Gas Price Risk Management				
276 GJ/d	Fixed price – natural gas contract	Oct. 07 – Dec. 07	Cdn$3.60[(d)]	$ (52)
276 GJ/d	Fixed price – natural gas contract	Jan. 08 – Dec. 08	Cdn$4.16[(d)]	(205)
				$ (257)
Refined Product Price Risk Management				
10,000 bbl/d	NYMEX Heating oil 3-way contract	Jan. 08 – Dec. 08	U.S.$145.00 - $222.17 ($193.00)[(f)]	$ (11,268)
6,000 bbl/d	Platt's fuel oil 3-way contract	Jan. 08 – Dec. 08	U.S.$43.00 - $63.21 ($51.67)[(g)]	(5,075)
2,000 bbl/d	NYMEX Heating oil collar	Jan. 08 – Dec. 08	U.S.$190.00 - $217.50[(h)]	(2,910)
2,000 bbl/d	Platt's fuel oil collar	Jan. 08 – Dec. 08	U.S.$51.00 - $58.68[(i)]	(2,611)
4,000 bbl/d	NYMEX Heating oil 3-way contract	Jan. 09 – Jun. 09	U.S. $160.00 - $229.50 ($198.00)[(j)]	(794)
6,000 bbl/d	Platt's fuel oil 3-way contract	Jan. 09 – Jun. 09	U.S. $48.67 - $65.09 ($56.17)[(k)]	(1,690)
				$ (24,348)
Electricity Price Risk Management				
35 MWH	Electricity price swap contracts	Oct. 07 – Dec. 08	Cdn $56.69	**$ 9,807**
Total net fair value deficiency of risk management contracts				**$ (26,934)**

(a) 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.

(b) This is the average price of the price floors. Harvest realizes this price plus 67-79%, or an average of 72%, of the difference between spot price and the given floor price.

(c) This is the average price of the price floors. Harvest realizes this price plus 67-79%, or an average of 73%, of the difference between spot price and the given floor price.

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

(e) Each group of puts and calls reflect an "indexed put option". These series of puts and calls serve to fix a floor price while retaining upward price exposure on a portion of price movements above the floor price. This contract contains an annual escalation factor such that the fixed price is adjusted each year.

(f) If the market price is below $145.00, price received is market price plus $48.00; if the market price is between $145.00 and $193.00, the price received is $193.00; if the market price is between $193.00 and the average ceiling of $222.17, the price received is market price; if the market price is over the average ceiling of $222.17, price received is the stated ceiling price.

(g) 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 average ceiling of $63.21, the price received is market price; if the market price is over the average ceiling of $63.21, price received is the stated ceiling price.

(h) If the market price is below $190.00, price received is $190.00; if the market price is between $190.00 and $217.50, the price received is market price; if the market price is over the ceiling of $217.50, price received is $217.50.

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

(j) If the market price is below $160.00, price received is market price plus $38.00; if the market price is between $160.00 and $198.00, the price received is $198.00; if the market price is between $198.00 and the average ceiling of $229.50, the price received is market price; if the market price is over the average ceiling of $229.50, price received is the stated ceiling price.

(k) If the market price is below the average floor of $48.67, price received is market price plus $7.50; if the market price is between the average floor price of $48.67 and $56.17, the price received is $56.17; if the market price is between $56.17 and the average ceiling of $65.09, the price received is market price; if the market price is over the average ceiling of $65.09, price received is the stated ceiling price.

For the three and nine months ended September 30, 2007, the total unrealized gain/loss on risk management contracts recognized in the consolidated statement of income and comprehensive income was a loss of $21.9 million and a loss of $25.0 million respectively (a gain of $77.1 million and $36.0 million – three and nine months ended September 30, 2006), 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.

17. Segment Information

Harvest operates in Canada and has two reportable operating segments for the three and nine month periods ending September 30, 2007, 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, home heating business and the supply of refined products to commercial and wholesale customers. For the three and nine month periods ending September 30, 2006, Harvest's only operating segment was the upstream operations.

	Three months ended September 30, 2007		
	Downstream[1]	Upstream[1]	Total
Revenue	$ 789,612 [2]	$ 298,708	**$ 1,088,320**[3]
Royalties	-	(56,806)	**(56,806)**
Realized net losses on risk management contracts	-	(1,793)	**(1,793)**
Unrealized net losses on risk management contracts[4]	(4,469)	(17,466)	**(21,935)**
Less:			
Purchased products for resale and processing	747,010	-	**747,010**
Operating[5]	53,737	80,189	**133,926**
Transportation and marketing	10,673	3,412	**14,085**
General and administrative	522	4,159	**4,681**
Depletion, depreciation, amortization and accretion	17,280	113,116	**130,396**
	$ (44,079)	$ 21,767	**$ (22,312)**
Interest and other financing charges on short term debt			**606**
Interest and other financing charges on long term debt			**35,764**
Foreign exchange gain			**(16,102)**
Large corporations tax and other tax			**(85)**
Future income tax			**(54,306)**
Net income			**$ 11,811**
Total Assets[1]	$ 1,499,663	$ 4,085,988	**$ 5,585,651**
Capital Expenditures			
Development and other activity	$ 12,468	$ 73,323	**$ 85,791**
Business acquisitions	-	140,518	**140,518**
Property acquisitions	-	4,017	**4,017**
Property dispositions	-	(5,157)	**(5,157)**
Total expenditures	$ 12,468	$ 212,701	**$ 225,169**
Property, plant and equipment			
Cost	$ 1,146,661	$ 4,230,426	**$ 5,377,087**
Less: Accumulated depletion and depreciation	(57,535)	(1,032,039)	**(1,089,574)**
Net book value	$ 1,089,126	$ 3,198,387	**$ 4,287,513**
Goodwill, beginning of period	$ 191,916	$ 656,248	**$ 848,164**
Addition (reduction) to goodwill	(12,717)	20,546	**7,829**
Goodwill, end of period	$ 179,199	$ 676,794	**$ 855,993**

(1) *Accounting policies for segments are the same as those described in the Significant Accounting Policies*
(2) *Of the total downstream revenue for the three month period ended September 30, 2007, $632.3 million is from one customer. No other single customer within either division represents greater than 10% of Harvest's total revenue.*
(3) *Of the total consolidated revenue for the three months ended September 30, 2007, $453.8 million is attributable to sales in Canada, while $634.5 million is attributable to sales in the United States.*
(4) *There is no intersegment activity with the exception of intersegment risk management contracts for the period of January 1, 2008 to December 31, 2008. For the three month period ended September 30, 2007 the net unrealized mark-to-market loss on these contracts is $4.5 million for the downstream segment and the net unrealized gain is $4.5 million for the upstream segment.*
(5) *Downstream operating expenses include $6.6 million of turnaround and catalyst costs related to the planned shutdown of the Isomax and Platformer commencing on September 21, 2007.*

	Nine months ended September 30, 2007					
		Downstream[1]		Upstream[1]		Total
Revenue	$	2,474,044 [2]	$	876,435	$	**3,350,479** [3]
Royalties		-		(160,003)		**(160,003)**
Realized net losses on risk management contracts		-		(8,916)		**(8,916)**
Unrealized net losses on risk management contracts[4]		(7,633)		(17,409)		**(25,042)**
Less:						
Purchased products for resale and processing		2,087,948		-		**2,087,948**
Operating[5]		148,019		224,818		**372,837**
Transportation and marketing		27,075		9,599		**36,674**
General and administrative		1,224		30,324		**31,548**
Depletion, depreciation, amortization and accretion		54,854		338,965		**393,819**
	$	147,291	$	86,401	$	**233,692**
Interest and other financing charges on short term debt						**4,986**
Interest and other financing charges on long term debt						**115,840**
Foreign exchange gain						**(98,460)**
Large corporations tax and other tax						**39**
Future income tax						**123,378**
Net income					$	**87,909**
Total Assets[1]	$	1,499,663	$	4,085,988	$	**5,585,651**
Capital Expenditures						
Development and other activity	$	27,222	$	270,031	$	**297,253**
Business acquisitions		-		170,782		**170,782**
Property acquisitions		-		15,103		**15,103**
Property dispositions		-		(37,355)		**(37,355)**
Total expenditures	$	27,222	$	418,561	$	**445,783**
Property, plant and equipment						
Cost	$	1,146,661	$	4,230,426	$	**5,377,087**
Less: Accumulated depletion and depreciation		(57,535)		(1,032,039)		**(1,089,574)**
Net book value	$	1,089,126	$	3,198,387	$	**4,287,513**
Goodwill, beginning of period	$	209,930	$	656,248	$	**866,178**
Addition (reduction) to goodwill		(30,731)		20,546		**(10,185)**
Goodwill, end of period	$	179,199	$	676,794	$	**855,993**

(1) Accounting policies for segments are the same as those described in the Significant Accounting Policies
(2) Of the total downstream revenue for the nine month period ended September 30, 2007, $2,106.8 million is from one customer. No other single customer within either division represents greater than 10% of Harvest's total revenue.
(3) Of the total consolidated revenue for the nine months ended September 30, 2007, $1,237.2 million is attributable to sales in Canada, while $2,113.3 million is attributable to sales in the United States.
(4) There is no intersegment activity with the exception of intersegment risk management contracts for the period of January 1, 2008 to December 31, 2008. For the nine month period ended September 30, 2007 the net unrealized mark-to-market loss on these contracts is $7.6 million for the downstream segment and the net unrealized gain is $7.6 million for the upstream segment.
(5) Downstream operating expenses include $6.6 million of turnaround and catalyst costs related to the planned shutdown of the Isomax and Platformer commencing on September 21, 2007.

18. Change in Non-Cash Working Capital

	Three months ended		Nine months ended	
	Sept 30, 2007	Sept 30, 2006	**Sept 30, 2007**	Sept 30, 2006
Changes in non-cash working capital items:				
Accounts receivable	**$ 61,893**	$ (382)	**$ 21,625**	$ (10,303)
Prepaid expenses and deposits	**(334)**	(1,144)	**1,690**	(2,207)
Current portion of risk management contract assets	**(5,175)**	(8,147)	**(4,250)**	4,809
Inventory	**(12,114)**	-	**(33,881)**	-
Current portion of future income tax asset	**-**	-	**-**	22,975
Accounts payable and accrued liabilities	**19,067**	39,664	**(12,948)**	16,699
Cash distribution payable	**1,116**	3,330	**9,251**	1,752
Current portion of risk management contract liabilities	**24,675**	(44,600)	**19,850**	(41,983)
	$ 89,128	$ (11,279)	**$ 1,337**	$ (8,258)
Changes relating to operating activities	**$ 57,743**	$ (1,073)	**$ (34,005)**	$ (17,824)
Changes relating to financing activities	**(2,050)**	7,879	**9,413**	(10,891)
Changes relating to investing activities	**15,096**	33,477	**(14,382)**	15,635
Add: Other non-cash changes	**18,339**	(51,562)	**40,311**	4,822
	$ 89,128	$ (11,279)	**$ 1,337**	$ (8,258)

19. Commitments, Contingencies and Guarantees

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

Harvest has one significant commitment at September 30, 2007, its Supply and Offtake Agreement with Vitol Refining S.A. ("Vitol"). This agreement provides that the ownership of substantially all crude oil feedstock and refined product inventory at the refinery be retained by Vitol and that for a minimum period of up to October 2008, with six months notice required thereafter, Vitol will be granted the right and obligation to provide crude oil feedstock for delivery to the refinery, as well as the right and obligation to purchase substantially all refined products produced by the refinery. As such, at September 30, 2007, North Atlantic had commitments totaling approximately $600.3 million in respect of future crude oil feedstock purchases and related transportation from Vitol. Included in this total is approximately $330.4 million relating to the SOMO contract discussed below.

In June 2007 Vitol entered into a six month term contract with Iraq's State Oil Marketing Organization ("SOMO") for 33,000 bbl/day of Basrah crude oil at market prices on behalf of Harvest per the Supply and Offtake Agreement. The remaining commitment (4.3 million barrels) is included in the total feedstock commitment disclosed below.

The following is a summary of Harvest's contractual obligations and commitments as at September 30, 2007:

	Payments Due by Period						
	2007	2008	2009	2010	2011	Thereafter	Total
Debt repayments (1)	$ -	$ -	$ 65,000	$1,140,119	$ 248,700	$ -	$1,453,819
Purchase commitments(2)	11,861	2,880	-	-	-	-	14,741
Operating leases(3)	2,233	7,486	6,471	5,568	5,188	1,862	28,808
Pension contributions(4)	195	1,510	1,835	2,219	2,586	19,147	27,492
Transportation agreements(5)	518	1,596	1,103	461	219	189	4,086
Feedstock commitments(6)	377,851	222,432	-	-	-	-	600,283
Contractual obligations	$ 392,658	$ 235,904	$ 74,409	$1,148,367	$ 256,693	$ 21,198	$2,129,229

(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 commitment , equipment rental contracts and downstream purchase commitments.
(3) Relating to building and automobile leases.
(4) Relating to expected contributions for employee benefit plans [see Note 15].
(5) Relating to oil and natural gas pipeline transportation agreements.
(6) Relating to crude oil feedstock purchases and related transportation costs [see Note 19 above].

20. Subsequent Events

Subsequent to September 30, 2007, Harvest declared a distribution of $0.38 per unit payable to Unitholders of record on October 22, 2007 which is payable on November 15, 2007.

Between October 1, 2007 and November 5, 2007, an additional U.S. $218.1 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 19].

On November 8, 2007, Harvest declared a distribution of $0.30 per unit payable to Unitholders of record on November 21, 2007, December 31, 2007, January 24, 3008 and February 22, 2008.

21. Related Party Transactions

During the three and nine month periods ended September 30, 2007, in the normal course of operations, Vitol Refining S.A. purchased $128.5 million and $259.7 million respectively of Iraqi crude oil through the Supply and Offtake Agreement at fair market value for processing, which has been sourced from a private corporation of which a director of Harvest is a director and holds a minority ownership interest. As at September 30, 2007, $34.0 million related to these transactions is included in accounts payable and accrued liabilities and $55.5 million is included in feedstock commitments for the purchase of Iraqi crude oil [See Note 19]. None of the U.S. $218.1 million committed to the purchase of feedstock inventory under the Supply and Offtake Agreement held with Vitol Refining S.A. between October 1, 2007 and November 5, 2007 [see Note 20] was purchased from this private corporation.

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