Harvest Energy Trust

Financial & Operating Highlights

The table below provides a summary of our financial and operating results for the three month periods ended March 31, 2007 and 2006. Detailed commentary on individual items within this table is provided in Harvest's Management's Discussion and Analysis, filed on SEDAR or available on our website.

	Three Month Period Ended March 31		
($000s except where noted)	**2007**	2006	Change
Revenue, net[(1)]	**1,011,094**	131,432	669%
Cash Flow[(2)]	**213,941**	100,971	112%
Per trust unit, basic[(2)]	**$ 1.68**	$ 1.23	37%
Per trust unit, diluted[(2)]	**$ 1.52**	$ 1.22	25%
Net income (loss)	**69,850**	(33,937)	306%
Per trust unit, basic	**$ 0.55**	$ (0.41)	234%
Per trust unit, diluted	**$ 0.55**	$ (0.41)	234%
Distributions declared	**145,270**	94,812	53%
Distributions declared, per trust unit	**$ 1.14**	$ 1.11	3%
Payout ratio [(2)]	**68%**	94%	(26%)
Bank debt	**1,363,222**	201,652	576%
Senior debt	**279,612**	292,000	(4%)
Convertible Debentures	**793,184**	242,244	227%
Total long-term financial liabilities	**2,436,018**	735,896	231%
Total assets	**5,800,346**	3,470,653	67%
PETROLEUM AND NATURAL GAS OPERATIONS			
Daily Production			
Light to medium oil (bbl/d)	**27,034**	23,900	13%
Heavy oil (bbl/d)	**15,614**	15,182	3%
Natural gas liquids (bbl/d)	**2,496**	1,709	46%
Natural gas (mcf/d)	**101,282**	73,337	38%
Total daily sales volumes (boe/d)	**62,024**	53,014	17%
Cash capital expenditures	**148,487**	103,239	44%
REFINING AND MARKETING OPERATIONS			
Average daily throughput (bbl/d)	**113,711**	-	n/a
Aggregate throughput (mbbl)	**10,234**	-	n/a
Cash capital expenditures	**4,883**	-	n/a

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

(2) These are non-GAAP measures; please refer to "Non-GAAP Measures" in Harvest's first quarter 2007 MD&A filed on SEDAR.

Message to Unitholders

The first quarter of 2007 was an active and very successful period for Harvest. In the upstream business, we delivered on our business plan with an active capital investment program that was already demonstrating its success by the end of the quarter. Most impressively however, we saw the value of our North Atlantic refining and marketing business acquisition which we completed in the fourth quarter of 2006 with its significant and impressive contribution to the organization's results. During the quarter, approximately 63% of our cash flow came from the upstream business where we find, develop and produce crude oil and natural gas in Western Canada in the provinces of Alberta, Saskatchewan and British Columbia. The remaining 37% was attributable to the downstream refining and marketing business located in the Province of Newfoundland and Labrador. The financial performance of the refinery significantly exceeded the expectations that we had for this business at the start of the quarter. We had high expectations when we purchased North Atlantic last year, and we are pleased to report that those expectations have been not only met but exceeded by the success that we have already achieved in 2007. Today, Harvest Energy is an integrated oil company active across the country with a diversified portfolio of assets and related businesses that provide us future opportunities and position Harvest to be a very long-term, sustainable organization for many years to come.

During the first quarter, very strong refining margins (or 'crack spreads') coupled with robust commodity prices contributed to our cash flow per unit of $1.68 and payout ratio of 68%. This is a significant improvement over our fourth quarter 2006 cash flow of $1.35 per unit and 86% payout ratio. The strong refined product pricing environment (bolstered by a shortage of refinery capacity in North America, as well as normal seasonality of gasoline prices which are typically stronger in the summer driving season) has continued into the second quarter. As a result, we were able to confidently declare our second quarter monthly distributions at C$0.38 per unit.

One of the drivers behind Harvest's entry into the downstream business was the realization that good value opportunities exist for those involved in the refining or upgrading business because refining capacity in North America is very tight. This means that supply and demand for refined products are closely balanced, such that even minor disruptions to the supply of refined products can impact inventories and result in significant price increases. This phenomenon occurred in the first quarter, as several Canadian and U.S. based refineries experienced disruptions that impacted refined product supply. In response to this as well as concerns over lower inventories, prices for refined product rose sharply in the first quarter and have remained strong into the second quarter. Particular strength was seen in 'RBOB' (Reformulated Blend for Oxygenate Blend) gasoline, and to a lesser extent in distillate prices such as heating oil (diesel) and jet fuel. As a result of the strength in individual product prices, crack spreads also posted strong advances during February and March. The commonly quoted NYMEX 2-1-1 crack spread averaged U.S.$12.14 per barrel during the first quarter, 37% higher than the fourth quarter of 2006. North Atlantic's realized gross margin of U.S.$11.85 per barrel was also 27% higher than the fourth quarter of U.S.$9.32 per barrel. Historically, the first quarter of the year is one of the weaker periods for crack spreads, but in 2007, we saw strengthening prices by the middle of February which continued beyond the end of the calendar quarter. During the month of March, the gross margin that Harvest realized from the refining business was almost twice the amount we had budgeted for that month.

Throughput at the refinery totaled 113,711 bbl/d during the quarter, and the refined product slate was weighted approximately 32% to gasoline, 41% to distillates and 27% to heavy fuel oil, and is expected to remain relatively stable for the balance of 2007. However, we have made some minor adjustments within the refinery to maximize the production of gasoline relative to distillates due to continued strong gasoline prices. Our refinery units give us the ability to make small (i.e. 1-2%) adjustments to the product slate to maximize margins. Since the summer driving season tends to reduce gasoline inventories, prices tend to be the strongest during the second and third calendar quarters, and we have responded to this by making adjustments to our refining process.

For the full year, we anticipate our throughput volumes will average 111,400 bbl/d, after the fuel consumed by the refinery is deducted from the feedstock volumes. Our 2007 maintenance capital of $30 million for the refinery will be allocated to projects that help maintain the high performance of our facility units. An additional $30 million has been budgeted in 2007 for discretionary projects, which are focused on enhancing the cash flow generating capability of the refinery. This discretionary capital includes the commencement of the visbreaker project discussed in our year end results. The visbreaker project will effectively upgrade approximately 1,500 bbl/d of heavy fuel oil into higher value distillate products. Heavy fuel oil historically sells at a discount to benchmark West Texas Intermediate ("WTI") prices of approximately U.S.$20/bbl, compared to distillates which have sold at a premium of approximately U.S.$10.50/bbl above benchmark WTI prices over the past two years. As a result, the economics of this project are very attractive and we anticipate that the project will pay for itself in less than one year. Additional work continues on our longer term opportunities, including projects such as a coker which would enable more complete upgrading of the heavy fuel oil. Additional discretionary projects in 2007 include opportunities that provide growth in the near term while also positioning for future growth.

The strong results we achieved in our downstream business during the first quarter helped support our cash flow by providing an offset to the seasonal softness we experience during the winter months in our upstream business. Consistent with the prior year, our first quarter 2007 capital spending in the upstream oil and natural gas business represented a substantial portion (almost 50%) of our overall budget for the year. We successfully invested $148.5 million into our upstream business and drilled 92 gross wells with a success rate of 97%. The focus of our drilling program was primarily oil targets with 80% of the net wells drilled exploiting our light, medium and heavy oil opportunities. Of this total, 11 wells were drilled in Southeast Saskatchewan, 12 at Red Earth, 6 in Lloydminster, 5 in Markerville, and we drilled 31 horizontal wells in Hay River.

The significant ‘front-end loading’ and oil weighting of our capital program is primarily due to activity at our Hay River property. This area is only accessible during the winter months when the ground is frozen. Given the large future recovery potential of the resource at Hay River (only 6% has been recovered to date on a pool that has over 200 million barrels of estimated original oil in place), we began work on an all season access road in late 2006 and through the first quarter of 2007. This road will enable year-round access for service rigs, services and personnel into this key area, further supporting our ability to both optimize our operations, and maximize the recovery of this large resource. As is typically the case during our active winter program, our oil production is negatively impacted by approximately 500 boepd, and we also incur a disproportionate share (approximately 50%) of our annual operating expenses, thus distorting our per barrel operating costs at Hay during the first quarter. The incremental production stemming from our 2007 drilling in Hay River is expected to come on-stream in the second quarter.

The production softness attributable to Hay River was further compounded by a significant winter storm in the Lloydminster area that resulted in 400 bbl/d of heavy crude oil being shut in for most of January and February until production was restored to full capacity. Despite these regional challenges, we were pleased with our ability to effectively deliver a significant first quarter capital program, and believe the geographic diversity of our assets helps to mitigate the impact from any one area.

Given the strong pricing environment for oil, our decision to largely focus on our oil exploitation opportunities has resulted in our natural gas production following a typical decline. Late in the first quarter, we did complete the construction of a gas processing facility in our Cairo area which will result in new liquids rich gas volumes being brought on in the second quarter.

We continue to pursue opportunities to enhance our asset base both in the upstream and downstream businesses. We see a number of opportunities to increase value for investors through business development activities in the downstream business and we continue to consider and evaluate those opportunities. The growing recognition of the value and importance of strategically located refining and marketing assets such as North Atlantic provides opportunity for value creation. In the upstream, we continue to seek out additional upstream acquisition prospects that would enable us to expand on our existing asset base at a reasonable cost and bring further value creation opportunities to the company. The acquisition market in western Canada has become more affordable over the past two quarters, primarily attributable to the Canadian government’s trust tax announcement and the uncertainty it poses for trusts as well as junior exploration and production companies. This uncertainty, coupled with commodity price volatility, has contributed to more reasonable and therefore more attractive asset prices and acquisition values.

As has been the norm through our history, we target assets that have attractive cash flow characteristics but also offer high quality enhancement and investment opportunities. Such characteristics allow us to create value with our hands-on technical approach to managing assets executed by our top tier employee base. We intend to pursue these types of opportunities while maintaining a prudent financial structure. During the quarter, we successfully completed an equity and convertible debenture financing, which enabled us to fully repay the $290 million that remained outstanding on a $350 million bridge loan (due in April 2008) that we incurred to finance our North Atlantic acquisition in late 2006. Since making that acquisition in the fourth quarter and despite the challenges imposed on some of our peers in the income trust and energy sector, we have been able to raise funds of almost $1 billion from the capital markets.

With all of the bridge loan obligations repaid, Harvest’s bank debt is now comprised solely of a three year revolving extendible credit facility (which has just been enlarged and substantially extended by the syndicate of lenders who have shown great support for our business plan), supplemented by a US$250 million senior note due in 2011, and convertible debentures with an average term of over 6 years, repayable in equity as required. It should be noted that approximately 80% of our convertible debentures are convertible by the holder into units of Harvest at prices less than or equal to the current market price. We are comforted by the lack of any near-term refinancing risk, and intend to use further equity financing to support future acquisitions.

We are pleased by the total return of approximately 30% that our investors have enjoyed year to date in 2007. As always, we thank all of our stakeholders for your continued support and look forward to reporting on our progress for the balance of the year.

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 month periods ended March 31, 2007 and 2006. The information and opinions concerning our future outlook are based on information available at May 8, 2007.

When reviewing our 2007 results and comparing them to 2006, readers should be cognizant that the 2007 results include three 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 whereas the comparative results in 2006 include only two months of operations from our acquisition of Viking. This significantly impacts the comparability of our operations and financial results for the three month period ended March 31, 2007 to the comparative period 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 ("6 mcf") of natural gas to one (1) 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 Cash Flow, Operating Income, Payout Ratio, Cash General and Administrative Expenses and Operating Netbacks and with respect to the refining industry, Gross Margin and Operating Income which are each defined in this MD&A including tables with their calculation. 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.

Consolidated Financial and Operating Highlights – First Quarter 2007

- Cash Flow of $213.9 million for the three month period ended March 31, 2007, an increase of $113.0 million over the prior year primarily due to our acquisitions in 2006 and continued strength in oil prices.
- Operating Cash Flow from North Atlantic of $94.7 million, reflecting the combined benefits of robust refining margins and solid refinery operating performance as throughput averaged 113,711 bbls/d.
- Operating Cash Flow from our petroleum and natural gas operations of $158.4 million with production averaging 62,024 boe/d, a narrowing of oil price differentials and reduced losses on the settlement of price risk management contracts.
- Completed a $148.5 million capital program in western Canada, drilling 92 gross petroleum and natural gas wells with a success rate of 97% focusing on oil producing opportunities resulting in an exit production rate of approximately 66,000 boe/d.
- Maintained our monthly distributions of $0.38 per trust unit through the quarter resulting in a Payout Ratio of 68% and announced the continuation of a $0.38 per trust unit monthly distribution for the second quarter of 2007.
- Increased our Three Year Extendible Revolving Credit Facility by $200 million to $1.6 billion and extended the maturity date on $1,535 million to April 2010.

- Raised $357.4 million with the issuance of 6,146,750 trust units and $230 million principal amount of convertible debentures in February 2007, bolstering our balance sheet.

SELECTED INFORMATION

The table below provides a summary of our financial and operating results for the three month periods ended March 31, 2007 and 2006. Detailed commentary on individual items within this table is provided elsewhere in this MD&A.

	Three Month Period Ended March 31		
($000s except where noted)	**2007**	2006	Change
Revenue, net[1]	**1,011,094**	131,432	669%
Cash Flow[2]	**213,941**	100,971	112%
Per trust unit, basic[2]	**$ 1.68**	$ 1.23	37%
Per trust unit, diluted[2]	**$ 1.52**	$ 1.22	25%
Net income (loss)	**69,850**	(33,937)	306%
Per trust unit, basic	**$ 0.55**	$ (0.41)	234%
Per trust unit, diluted	**$ 0.55**	$ (0.41)	234%
Distributions declared	**145,270**	94,812	53%
Distributions declared, per trust unit	**$ 1.14**	$ 1.11	3%
Payout ratio [2]	**68%**	94%	(26%)
Bank debt	**1,363,222**	201,652	576%
Senior debt	**279,612**	292,000	(4%)
Convertible Debentures	**793,184**	242,244	227%
Total long-term financial liabilities	**2,436,018**	735,896	231%
Total assets	**5,800,346**	3,470,653	67%
PETROLEUM AND NATURAL GAS OPERATIONS			
Daily Production			
Light to medium oil (bbl/d)	**27,034**	23,900	13%
Heavy oil (bbl/d)	**15,614**	15,182	3%
Natural gas liquids (bbl/d)	**2,496**	1,709	46%
Natural gas (mcf/d)	**101,282**	73,337	38%
Total daily sales volumes (boe/d)	**62,024**	53,014	17%
Cash capital expenditures	**148,487**	103,239	44%
REFINING AND MARKETING OPERATIONS			
Average daily throughput (bbl/d)	**113,711**	-	n/a
Aggregate throughput (mbbl)	**10,234**	-	n/a
Cash capital expenditures	**4,883**	-	n/a

(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.

REVIEW OF FIRST QUARTER PERFORMANCE

Harvest is a fully integrated energy trust with our petroleum and natural gas business focused on the operation and development of quality properties in western Canada 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.

In the first quarter of 2007, we generated Cash Flows of $213.9 million ($1.68 per basic trust unit) compared to Cash Flows of $101.0 million ($1.23 per basic trust unit) in the first quarter of 2006. This $113.0 million increase in Cash Flow is predominately attributed to the incremental impact of the North Atlantic acquisition and to a lesser extent, the impact of the Birchill acquisition. During the first quarter of 2007, our petroleum and natural gas operations benefited from the significant narrowing of the price differentials between western Canadian crudes (Edmonton Par and Bow River) and the West Texas Intermediate ("WTI") benchmark price as compared to the prior year. In addition, the settling of our price risk management contracts resulted in a nominal loss this quarter as the floor price of our oil price contracts averaged US$55.67 as compared to a floor price of US$42.11 and a $9.2 million loss in the first quarter of 2006.

During the first three months of 2007, the North Atlantic refinery operated at near capacity reporting 113,711 bbls/d of throughput and benefited from a gross margin (or crack spread) of US$11.85 per bbl. At the end of November 2006, an extended turnaround of the Refinery was completed and the throughput during the first quarter of 2007 reflects minimal operating disruptions and yields as expected. North Atlantic's crack spread in the first quarter improved by approximately 27% over the 73 days included in our fourth quarter of 2006 while the "2-1-1 Crack Spread" benchmark improved by 37% over the same period. As expected, North Atlantic's gross margin did not enjoy the full benefit of improving crack spreads as the narrowing of the price differential on the medium gravity sour crude oil processed by the Refinery increased our costs relative to the WTI benchmark price and the cost of vacuum gas oil also increased. Furthermore, our Refinery produces approximately 25% heavy fuel oil which is not factored into the "2-1-1 Crack Spread" benchmark. The Refinery operating costs were as anticipated.

Production from our petroleum and natural gas operations for the first quarter of 2007 was 62,024 boe/d and includes three months of production from the assets acquired in the Viking and Birchill acquisitions compared to the first quarter of 2006 which includes only two months of the Viking acquisition. Our first quarter production is lower than our 2006 year end exit production of 65,023 boe/d, as it reflects reduced volumes from the Hay River property which is a "winter access only" property that requires substantially all drilling and maintenance activity to be performed when the ground is frozen. During the first quarter, the prices realized on our production have improved by 27% for heavy oil and 11% for light to medium oil reflecting the narrowing of quality differentials as the WTI benchmark price fell by 8% on a year-over-year basis. Our price for natural gas was essentially unchanged. Our gross revenues during the first quarter of 2007 were up 30% before the impact of price risk management and royalties and our net revenues of $226.5 million increased by 73% after deducting both realized and unrealized price risk management losses and royalties. First quarter 2007 operating costs were $72.3 million, which is $22.2 million higher than the first quarter of the prior year. This increase is primarily due to the impact of the Viking and Birchill acquisitions, but also reflects increased workover and repairs and maintenance costs. On a per unit basis, operating cost increases are magnified, as many of the workover activities temporarily shut-in production. Overall, our operating netback during the first three months of 2007 was $29.76 per boe compared to $25.30 in the comparative period of 2006, an 18% improvement.

Distributions declared during the first quarter of 2007 totaled $1.14 per trust unit resulting in our payout ratio being 68% of Cash Flow compared to $1.11 and 94% (before deducting $5.1 million of cash transaction costs relating to the Viking acquisition) in the prior year. For the first quarter of 2007, the participation in our distribution reinvestment plan was approximately 30% while in the comparative period, the participation rate was approximately 43%. Our DRIP plan enables us to settle our distributions through the issue of units, allowing us to use the cash to reinvest in our capital program or for debt repayment.

In February 2007, we issued $230 million principal amount of convertible debentures and 6,146,750 trust units at a price of $23.40 per trust unit for net proceeds of $357.4 million. The net proceeds from this financing were used to repay the remaining $289.7 million on the Senior Secured Bridge Facility with the remaining $67.7 million applied to the drawn portion of our Three Year Extendible Revolving Credit Facility.

Subsequent to the end of the first quarter, we requested an extension of the maturity date from March 2009 to April 2010 for our $1.4 billion Three Year Extendible Revolving Credit Facility and sought to increase the facility from $1.4 billion to $1.6 billion. With our lenders consent, we have now upsized our facility to $1.6 billion and extended the maturity date to April 2010 on $1,535 million of the facility with one lender representing $65 million retaining the March 2009 maturity date.

Business Segments

With the acquisition of North Atlantic in October of 2006, our business has two segments: petroleum and natural gas in western Canada and refining and marketing in the province of Newfoundland and Labrador. Our petroleum and natural gas business consists of our production and development activities and our refining and marketing business consists of a medium gravity sour crude hydrocracking refinery with a crude oil throughput capacity of 115,000 barrels per day, 61 retail gas stations, 3 cardlock locations as well as a wholesale and home heating business. The following table presents selected financial information for our two business segments:

	Three Month Period Ended			
	2007			**2006**
(in 000's of Canadian dollars)	**Petroleum and natural gas**	**Refining and marketing**	**Total**	**Total**[3]
Revenue[1]	227,049	784,045	1,011,094	131,432
Operating income[2]	27,434	75,356	102,790	(23,164)
Capital expenditures	148,487	4,883	153,370	103,239
Total assets	4,071,277	1,729,069	5,800,346	3,470,653

(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 month period ended March 31, 2006, Harvest's operations consisted of only petroleum and natural gas operations.

PETROLEUM AND NATURAL GAS OPERATIONS

Financial and Operating Results

Our acquisitions of Viking in February 2006 and Birchill in August 2006 significantly impact the comparability of our first quarter results in 2007 with the results of the prior year. Throughout the first quarter of 2007, our production mix was approximately 48% light to medium oil and natural gas liquids, 25% heavy oil and 27% 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 petroleum and natural gas operations for the three month periods ended March 31, 2007 and 2006:

	Three Month Period ended March 31		
(in 000's of Canadian dollars except as noted below)	**2007**	2006	Change
Revenues	**$ 291,116**	$ 224,275	30%
Royalties	**(49,649)**	(43,115)	15%
Realized losses on price risk management contracts[1]	**(797)**	(9,208)	(91%)
Unrealized losses on price risk management contracts	**(14,121)**	(40,997)	(66%)
Net revenues excluding realized losses on electric power fixed price contracts	**226,549**	130,955	73%
Operating expenses	**72,296**	50,094	44%
Realized gains on electric power fixed price contracts	**(500)**	(477)	5%
Net operating expenses	**71,796**	49,617	45%
General and administrative expenses	**10,104**	5,812	74%
Transportation and marketing	**2,812**	1,623	73%
Transaction costs	**-**	11,742	n/a
Depreciation, depletion, amortization and accretion	**114,403**	85,325	34%
Operating Income (Loss)[2]	**27,434**	(23,164)	218%
Cash capital expenditures (excluding acquisitions)	**148,487**	103,239	44%
Property and business acquisitions, net	**30,953**	23,382	32%
Daily sales volumes			
Light to medium oil (bbl/d)	**27,034**	23,900	13%
Heavy oil (bbl/d)	**15,614**	15,182	3%
Natural gas liquids (bbl/d)	**2,496**	1,709	46%
Natural gas (mcf/d)	**101,282**	73,337	38%
Total (boe/d)	**62,024**	53,014	17%

(1) Includes amounts realized on WTI, heavy oil price differential 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 Month Period ended March 31		
Benchmarks	**2007**	2006	Change
West Texas Intermediate crude oil (US$ per barrel)	**58.16**	63.48	(8%)
Edmonton light crude oil ($ per barrel)	**67.11**	68.96	(3%)
Bow River blend crude oil ($ per barrel)	**50.04**	39.98	25%
AECO natural gas daily ($ per mcf)	**7.40**	7.52	(2%)
AECO natural gas monthly ($ per mcf)	**7.45**	9.27	(20%)
Canadian / U.S. dollar exchange rate	**0.854**	0.866	(1%)

The West Texas Intermediate ("WTI") crude oil price was 8% lower during the three month period ended March 31, 2007 than in the prior year. The reduction in the average WTI price was not fully reflected in the Edmonton light crude oil ("Edmonton Par") nor the Bow River blend crude oil benchmark prices which were 3% lower and 25% higher, respectively. During the first quarter of 2007, there was a significant narrowing in the differentials between these Canadian benchmark prices and the WTI price as compared to the prior year. This narrowing of the Edmonton Par to WTI differential is primarily attributed to strong demand for western Canadian light crude in 2007 as compared to 2006 when demand weakened due to operating disruptions at several light oil refineries in central Canada. The Canadian/US dollar exchange rate was relatively unchanged between the first quarter of 2007 and the first quarter of 2006 but offset the lower WTI price by approximately $1.00 relative to the Edmonton Par price.

For the three month period ended March 31, 2007, prices for heavy crude oil of $50.04 were 25% higher than in 2006 with Bow River differentials narrowing to 25.4% of Edmonton Par for the three month period ended March 31, 2007 compared to 42.0% in 2006. In the prior year, heavy oil inventory levels were higher than in 2007 and pipeline capacity limited the delivery of heavy crude to the US markets. As shown below, heavy oil differentials continue to narrow as compared to 2006 and 2005.

	2007	2006				2005		
Differential Benchmarks	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Bow River Blend differential to Edmonton Par	**25.4%**	30.3%	25.8%	22.9%	42.0%	40.0%	28.2%	39.6%

Compared to the prior year, AECO natural gas daily prices remained relatively unchanged for the three month period ended March 31, 2007 with a decrease of 2%, while AECO monthly prices for the same periods decreased by 20%.

Realized Commodity Prices

The following table provides a breakdown of our average prices by product and our overall net realized price before and after realized losses on price risk management contracts for the three month periods ended March 31, 2007 and 2006.

	Three Month Period ended March 31		
	2007	2006	Change
Light to medium oil ($/bbl)	**58.90**	53.06	11%
Heavy oil ($/bbl)	**44.54**	35.12	27%
Natural gas liquids ($/bbl)	**52.78**	56.69	(7%)
Natural gas ($/mcf)	**8.05**	8.10	(1%)
Average realized price ($/boe)	**52.15**	47.01	11%
Realized price risk management losses ($/boe)(1)	**(0.14)**	(1.93)	(93%)
Net realized price ($/boe)	**52.01**	45.08	15%

(1) Includes amounts realized on WTI, heavy oil price differential and foreign exchange contracts and excludes amounts realized on electric power fixed price contracts.

For the three months ended March 31, 2007, our average realized price was 11% higher before the realized losses on our price risk management contracts and 15% higher after deducting the realized losses on these contracts as compared to the prior year. Our realized price for oil in the current quarter averaged $53.64 before losses on crude oil price risk management contracts as compared to $46.09 in the first quarter of 2006, representing a 16% increase over the prior year. The increase in our average realized oil price during the first quarter is primarily due to the Bow River differential to Edmonton Par improving from a 42.0% discount in the prior year to a 25.4% discount in the current year. As 35% of our total production is priced off of the Bow River stream, it was expected that our average realized oil price increase would be greater than the change in the Edmonton Par price. During the first three months of 2007, the gains realized on the settlement of our crude oil price risk management contracts aggregated to $290,000 as compared to losses of $9.6 million in the first three months of 2006 as the floor price of our contracts has increased to US$55.67 compared to US$42.11 in the prior year.

In the first quarter of 2007, the realized price of our light to medium oil sales increased 11% compared to the prior year while the Edmonton Par price decreased 3% over the same period. Improved quality differentials for light to medium oil production realized in 2007 relative to the Edmonton Par benchmark price is the primary reason for our higher than expected realized price.

Our realized heavy oil price for the first quarter of 2007 of $44.54 was 27% higher than in the prior year primarily due to the significant narrowing in the Bow River differential to Edmonton Par noted above. The majority of our heavy oil production is priced off of the Bow River benchmark price.

During the three months ended March 31, 2007, our realized natural gas price of $8.05 was essentially unchanged (down by 1% compared to the prior year), reflecting the modest 2% decrease in the AECO daily price. During the first quarter of 2007, approximately 60% of our natural gas sales were priced off the AECO daily benchmark, approximately 30% sold off the AECO monthly benchmark with the remainder sold to aggregators. During the first quarter of 2007, the realized gain on the settlement of our natural gas price risk management contracts totaled $161,000 as compared to a $239,000 gain in the prior year.

Sales Volumes

The average daily sales volumes by product were as follows:

	Three Month Period ended March 31				
	2007		2006		
	Volume	**Weighting**	Volume	Weighting	% Volume Change
Light to medium oil (bbl/d)[1]	**27,034**	**44%**	23,900	45%	13%
Heavy oil (bbl/d)	**15,614**	**25%**	15,182	29%	3%
Total oil (bbl/d)	**42,648**	**69%**	39,082	74%	9%
Natural gas liquids (bbl/d)	**2,496**	**4%**	1,709	3%	46%
Total liquids (bbl/d)	**45,144**	**73%**	40,791	77%	11%
Natural gas (mcf/d)	**101,282**	**27%**	73,337	23%	38%
Total oil equivalent (boe/d)	**62,024**	**100%**	53,014	100%	17%

(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 March 31, 2007, average production was higher than in the prior year primarily due to the acquisition of Viking in February of 2006 and the acquisition of Birchill in the third quarter of 2006.

Light to medium oil production is 3,134 bbl/d higher compared to the prior year primarily due to one month's incremental production related to the acquisition of Viking (3,013 bbl/d) and a further three months of incremental production attributed to the acquisition of Birchill (1,050 bbl/d) partially offset by natural decline in production. In both years, our Hay River production has been disrupted as a result of significant routine maintenance turnarounds at production facilities and an extensive drilling program in this area where access is limited to winter only. In 2007, our Hay River production averaged 5,451 bbl/d for the first quarter, with our exit production rate at the end of March 2007 of approximately 6,800 bbl/d attributed to the success of the drilling program and a return to normal operations in the area.

Heavy oil production for the three months ended March 31, 2007 of 15,614 bbl/d remained relatively consistent with the prior year as approximately 3,000 bbl/d of incremental volumes from two heavy oil acquisitions (one in the fourth quarter of 2006 and another at the end of February 2007) was more than sufficient to offset the natural decline in our heavy oil properties. As in 2006, our production at Suffield during the first quarter of 2007 was 593 bbl/d below expectations due to "military lockdowns" and disruptions in water handling.

Natural gas production for the three month period ended March 31, 2007 of 101,282 mcf/d is 27,945 mcf/d higher than the prior year primarily due to the acquisition of Birchill in August 2006 adding approximately 16,500 mcf/d of incremental natural gas production plus a full three months of natural gas production from the Viking acquisition completed in February 2006. These acquisition related increases are partially offset by higher than expected production declines in the Markerville/Sylvan Lake area from wells drilled in 2006 where the initial flush production has stabilized. With much of our planned drilling directed to oil related prospects, our natural gas production will benefit primarily from the re-completion of existing wells and the tie in of wells drilled in 2006.

Revenues

(000s)		Three Month Period ended March 31 2007		2006	Change
Light to medium oil sales	**$**	**143,305**	$	114,123	26%
Heavy oil sales		**62,585**		47,987	30%
Natural gas sales		**73,370**		53,444	37%
Natural gas liquids sales and other		**11,856**		8,721	36%
Total sales revenue		**291,116**		224,275	30%
Realized risk management contract losses[1]		**(797)**		(9,208)	(91%)
Total revenues including realized risk management contract losses		**290,319**		215,067	35%
Realized gains on electric power price risk management contracts		**500**		477	5%
Unrealized losses on price risk management contracts		**(14,121)**		(40,997)	(66%)
Net Revenues, before royalties		**276,698**		174,547	59%
Royalties		**(49,649)**		(43,115)	15%
Net Revenues	**$**	**227,049**	$	131,432	73%

[1] Includes amounts realized on WTI, heavy oil price differential 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. Light to medium oil sales revenue for the three month period ended March 31, 2007 was $29.2 million (or 26%) higher than the comparative period, comprised of a $14.2 million favourable price variance resulting from the 11% increase in price and a $15.0 million favourable volume variance. The favourable volume variances over the prior year are primarily due to the acquisitions of Viking and Birchill in 2006 as well as the results of our drilling program which has focused on light to medium oil production.

Heavy oil sales revenue for the first quarter of 2007 increased $14.6 million (or 30%) compared to the same period in the prior year due primarily due to a favourable price variance of $13.2 million coupled with a favourable volume variance of $1.4 million. The significant narrowing of heavy oil differentials resulted in higher realized prices on our heavy oil. Our heavy oil production was essentially unchanged at 15,614 bbls/d for the first quarter of 2007 as compared to 15,182 in the prior year with the current period benefiting from an incremental month's production from the Viking assets, the two recent heavy oil acquisitions and new wells drilled in Hayter and Suffield in 2006 offset by natural declines and higher water cuts.

Natural gas sales revenue increased by $19.9 million (or 37%) for the three month period ended March 31, 2007 over the prior year primarily due to a favourable volume variance of $20.4 million offset by a modest $500,000 unfavourable price variance. Natural gas prices were essentially unchanged during the current year compared to the prior year with the favourable volume variance entirely attributed to the incremental gas production from the properties acquired in the Viking and Birchill acquisitions in 2006.

During the first quarter of 2007, our natural gas liquids and other sales increased by $3.1 million (or 36%) compared to the prior year. This increase is due to a $4.0 million favourable volume variance offset by a $0.9 million unfavourable price variance with the volume variance attributed to the same natural gas properties giving rise to our favourable natural gas volume variance.

Price Risk Management Contracts

Details of our price risk management contracts outstanding at March 31, 2007 are included in Note 15 of our interim consolidated financial statements for the three month period ended March 31, 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 during the respective periods:

	Three Month Period ended March 31					
	2007					2006
(000s)	Oil	Gas	Currency	Electricity	Total	Total
Realized (losses) / gains on price risk management contracts	$ 290	$ 161	$ (1,248)	$ 500	$ (297)	$ (8,731)
Unrealized (losses) / gains on price risk management contracts	(12,241)	(2,815)	1,362	(427)	(14,121)	(41,297)
Amortization of deferred gains relating to risk management contracts	-	-	-	-	-	300
Total (losses) / gains on risk management contracts	$ (11,951)	$ (2,654)	$ 114	$ 73	$ (14,418)	$ (49,728)

Our total realized loss on price risk management contracts was $297,000 for the three month period ended March 31, 2007 compared to $8.7 million for the same period in 2006, primarily the result of our oil price contracts being settled with a slight gain in the current year as compared to a loss of $9.6 million in the prior year.

Our realized gains on oil price contracts for the three months ended March 31, 2007 of $290,000 was a substantial improvement from the $9.6 million loss realized during the first quarter of the prior year. In the first quarter of 2007, we had WTI price risk management contracts on 30,000 bbl/d with downside protection at an average floor price of US $55.67 per bbl and 73% participation in prices over US $55.67 as compared to 26,250 bbl/d contracted with downside protection at an average floor price of US$42.11 and 59% participation in prices above US$42.11 for the three months ended March 31, 2006. As compared to 2006, the WTI price during the first quarter of 2007 averaged US$58.16, a decrease of US$5.32 from US$63.48 in the prior year. The elimination of losses on our oil price risk management contracts is the result of the higher contracted floor prices and the lower WTI price. We also had heavy oil price differential contracts protecting the differential on 1,000 bbl/d at 27.7% of WTI for the first three months of 2007 which was relatively close to the average heavy oil differential of 26.5% of WTI for the quarter. We have not entered into any crude oil price risk management contracts during the first quarter of 2007 as in light of our acquisition of the North Atlantic refinery we have concluded that the contracting for price protection on refined products is preferred to price protection on crude oil sales.

To protect against the possibility of soft natural gas prices, we entered into one natural gas price risk management contract for the period from November 2006 through March 2007 for 25,000 GJ/d with a floor price of $7.00 and a price cap of $12.50 and a second contract for the period from June 2006 to March 2007 for 25,000 GJ/d with a floor price of $5.00 and a price cap of $13.55. During the first quarter of 2007, the floor price of $7.00 on 25,000 GJ/d resulted in a $161,000 gain. During the first quarter of 2007, we entered into the following two natural gas price risk management contracts to protect our cash flows in the event of soft natural gas prices in the summer of 2007:

Quantity	**Term**	**Contracted Price**
20,000 GJ/d	April 2007 – March 2008	If AECO price is below $5.00, price received is market price plus $2.00 If AECO price is between $5.00 and $7.00, price received is $7.00 If AECO price is between $7.00 and $10.25, price received is market price. If AECO price is over $10.25, price received is $10.25
10,000 GJ/d	April 2007 – March 2008	If AECO price is below $5.00, price received is market price plus $2.00 If AECO price is between $5.00 and $7.00, price received is $7.00 If AECO price is between $7.00 and $10.30, price received is market price. If AECO price is over $10.30, price received is $10.30

During the first quarter of 2007, we had currency exchange rate contracts in place on US$8,750,000 per month at a fixed rate of approximately $0.89 which resulted in $1.3 million of losses settling the contracts as the exchange rate averaged approximately $0.85 during the quarter. Offsetting this loss was a realized foreign exchange gain of $0.5 million resulting from our participation in an oil sales contract which entitles us to elect on a monthly basis to accept settlement of the prior month's sales proceeds in US currency or to fix the currency exchange rate for a Canadian dollar settlement. For the balance of 2007, we have entered into contracts to fix the currency exchange rate on US$8,750,000 per month at an average rate of approximately $0.89.

We continue to recognize gains from our electric power price risk management contracts amounting to $500,000 during the first quarter of 2007 compared to $477,000 in the prior year. We enter into these contracts to provide protection from rising electric power prices. During the first quarter of 2007, Alberta's electric power price averaged $63.62 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 first quarter of 2007, we recorded an unrealized net loss on our price risk management contracts of $14.1 million, and at March 31, 2007, our price risk management contracts had an unrealized mark-to-market deficiency of $16.0 million as compared to a 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 month period ended March 31, 2007, our net royalties as a percentage of gross revenue were 17.1% (19.2% - three months ended March 31, 2006) and aggregated to $49.6 million ($43.1 million – three months ended March 31, 2006). The decrease in the royalty rate is attributable to lower freehold mineral taxes and a lower crown royalty rate on natural gas.

Operating Expenses

	Three Month Period ended March 31				
($000s)	**2007**	**Per BOE**	2006	Per BOE	Per BOE Change
Operating expense					
Power	**$ 13,773**	**$ 2.47**	$ 12,028	$ 2.52	(2%)
Workovers	**17,162**	**3.07**	8,392	1.76	74%
Repairs and maintenance	**13,634**	**2.44**	5,449	1.14	114%
Labour – internal	**3,618**	**0.65**	3,278	0.69	(6%)
Processing fees	**8,168**	**1.46**	3,933	0.82	78%
Fuel	**1,930**	**0.35**	3,887	0.81	(57%)
Labour – external	**3,960**	**0.71**	2,029	0.43	65%
Land leases and property tax	**3,126**	**0.56**	2,995	0.63	(11%)
Other	**6,925**	**1.24**	8,103	1.70	(27%)
Total operating expense	**72,296**	**12.95**	50,094	10.50	23%
Realized gains on electric power price risk management contracts	**(500)**	**(0.09)**	(477)	(0.10)	(10%)
Net operating expense	**$ 71,796**	**$ 12.86**	$ 49,617	$ 10.40	24%
Transportation and marketing expense	**$ 2,812**	**$ 0.50**	$ 1,623	$ 0.34	47%

Total operating expense increased by $22.2 million to $72.3 million for the three month period ended March 31, 2007 compared to the prior period. A significant portion of this increase is attributed to the additional production from the incremental month of activity for the Viking assets acquired in February 2006 and the activity associated with the assets from the Birchill acquisition completed in August 2006. However, the high demand for oilfield services leading to higher costs for well servicing, workovers, labour and well maintenance continues.

On a per barrel basis our operating costs have increased to $12.95 per boe, a 23% increase over 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 quarter of 2007 as compared to the prior year. The increased processing fees is directly related to our greater proportion of non-operated properties as a result of the acquisitions of Viking and Birchill. Generally, we incur higher processing fees on non-operated properties as although we own an interest in the well, we do 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 operating expenses benefit from our cost reduction initiatives such as the water disposal and fluid handling project in Suffield where we incurred approximately $13 million in capital expenditures in 2006 to lower electric power costs required to operate high water cut wells.

Our transportation and marketing expense of $2.8 million for the three months ended March 31, 2007 is $1.2 million higher (73%) than in the prior period. 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 crude oil to pipeline receipt points. As compared to the prior year, our natural gas production in the first quarter of 2007 of 101,282 mcf/d is 38% higher substantially related to the incremental natural gas production associated with our acquisition of Viking and Birchill in 2006 which has contributed to higher transportations costs. In late 2006, we changed our relationship with the pipeline operators such that the transportation commitments are now a direct responsibility of Harvest rather than the independent marketer of our production. This contributes to the increase in our transportation expense, but is more than offset by increases on realized prices.

Electric power costs represented approximately 19% of our total operating costs during the three months ended March 31, 2007 compared to approximately 24% in the prior year. Aggregate power costs have increased 15% to $13.8 million in the current quarter compared to $12.0 million in the comparative quarter. For the three months ended March 31, 2007, electric power prices per MWh were 12% higher than in the prior year, however, the impact of higher prices was offset on a per boe basis with lower consumption and a 17% increase in production. Our electric power price risk management contracts have resulted in a lower electric power cost on a per boe basis in the first quarter of both 2007 and 2006. The following table details the electric power costs per boe before and after the impact of our price risk management program.

	Three Month Period ended March 31		
(per boe)	**2007**	2006	Change
Electric power costs	**$ 2.47**	$ 2.52	(2%)
Realized gains on electricity risk management contracts	**(0.09)**	(0.10)	(10%)
Net electric power costs	**$ 2.38**	$ 2.42	(2%)
Alberta Power Pool electricity price (per MWh)	**$ 63.62**	$ 56.96	12%

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 Month Period ended March 31	
(per boe)	**2007**	2006
Revenues	**$ 52.15**	$ 47.01
Realized loss on risk management contracts(1)	**(0.14)**	(1.93)
Royalties	**(8.89)**	(9.04)
Operating expense(2)	**(12.86)**	(10.40)
Transportation and marketing expense	**(0.50)**	(0.34)
Operating netback(3)	**$ 29.76**	$ 25.30

(1) Includes amounts realized on WTI, heavy oil price differential and foreign exchange contracts, and excludes amounts realized on electricity contracts.
(2) Includes realized gains on electric power price risk management contracts of $0.09 per boe and $0.10 per boe for the three month periods ended March 31, 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 from our production on a per boe basis after deducting the directly related costs. For the three month period ended March 31, 2007, our operating netback of $29.76 is $4.46 per boe higher and an 18% improvement over the prior year. Higher oil prices in the current quarter compared to the first quarter in the prior year resulted in increased revenue of $5.14 per boe while reduced losses realized on our price risk management program of $1.79 per boe are not sufficient to fully offset an increase of $2.46 per boe in operating costs. Marginally lower royalties offset higher transportation costs.

General and Administrative ("G&A") Expense

	Three Month Period ended March 31		
(000s except per boe)	**2007**	2006	Change
Cash G&A[1]	**$ 7,205**	$ 6,053	19%
Unit based compensation expense	**2,899**	(241)	1,303%
Total G&A	**$ 10,104**	$ 5,812	74%
Cash G&A per boe ($/boe)	**1.29**	1.27	2%

[1] Cash G&A excludes the impact of our unit based compensation expense and for the three months ended March 31, 2006 $3.1 million of one time transaction costs.

For the three months ended March 31, 2007, Cash G&A costs increased by $1.2 million (or 19%) compared to the same period in 2006, which is attributed mainly to increased staffing levels with our integration of the staff from our acquisitions of Viking and Birchill adding more than 100 employees. Approximately 86% of our Cash G&A expenses are related to salaries and other employee related costs, while in the prior year only 66% 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. The remainder of the increases for the three month period ended March 31, 2007 compared to 2006 are due to higher office rental costs required for the additional staff and increased travel costs related to the refinery acquisition.

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 total unit based compensation expense for the three month period ended March 31, 2007 was $2.9 million. Our opening trust unit market price was $26.23 at January 1, 2007 and at March 31, 2007, our trust unit price had increased to $28.57. As a result, we have recorded an expense of $2.4 million on unexercised UARs for the three month period ended March 31, 2007. Our total unit based compensation expense has increased $3.1 million over the first quarter of the prior year after considering that $8.6 million of unit based compensation expense incurred in the first three months of 2006 was recorded as transaction costs.

In 2006, we have recorded transaction costs of $11.7 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 Month Period ended March 31		
(000s except per boe)	**2007**	2006	Change
Depletion, depreciation and amortization	**$ 105,896**	$ 77,395	37%
Depletion of capitalized asset retirement costs	**4,061**	4,282	(5%)
Accretion on asset retirement obligation	**4,446**	3,648	22%
Total depletion, depreciation, amortization and accretion	**$ 114,403**	$ 85,325	34%
Per boe ($/boe)	**20.49**	17.88	15%

Our overall depletion, depreciation, amortization and accretion ("DDA&A") expense for the three months ended March 31, 2007 is $29.1 million higher as compared to the prior year. Of this, $14.5 million is due to the incremental production from the merger with Viking in early 2006 and the acquisition of Birchill in August of 2006. The remaining $14.6 million of the increase is attributed to a higher depletion rate per boe, as our acquisitions in 2006 coupled with generally higher finding and development costs have increased our overall corporate DDA&A rate.

Capital Expenditures

	Three Month Period ended March 31	
(000s)	**2007**	2006
Land and undeveloped lease rentals	**$ 160**	$ 2,087
Geological and geophysical	**4,014**	1,000
Drilling and completion	**78,284**	66,516
Well equipment, pipelines and facilities	**63,345**	29,884
Capitalized G&A expenses	**2,553**	3,941
Furniture, leaseholds and office equipment	**131**	(189)
Development capital expenditures excluding acquisitions	**148,487**	103,239
Non-cash capital additions	**415**	390
Total development capital expenditures excluding acquisitions and non-cash items	**$ 148,902**	$ 103,629

During the first three months of 2007 we invested $148.5 million in drilling, operating optimization and enhancement projects compared to $103.2 million in the first quarter of the prior year. Approximately 53% of the 2007 expenditures were directly related to the drilling of 92 gross wells with a success rate of 97% as compared to 82 gross wells in 2006 and a success rate of 98%. As we expect the current strong oil pricing environment to continue, we continued to focus our drilling activity on oil opportunities with 65 of the 92 wells drilled targeting oil prospects.

The following summarizes Harvest's participation in gross and net wells drilled during the first three months of 2007:

	Total Wells		Successful Wells		Abandoned Wells	
Area	**Gross[1]**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Hay River	31	31.0	31	31.0	-	-
Southeast Saskatchewan	11	11.0	11	11.0	-	-
Red Earth	12	8.5	12	8.5	-	-
Suffield	5	5.0	4	4.0	1	1.0
Lloydminster	6	6.0	6	6.0	-	-
Markerville	5	1.9	5	1.9	-	-
Other Areas	22	9.7	20	9.1	2	0.6
Total	92	73.1	89	71.5	3.0	1.6

(1) Excludes 6 additional wells that we have an overriding royalty interest in.

In Hay River, the area with our most active drilling program, we continue to exploit our large Bluesky oil resource using multi-leg horizontal wells. Favourable weather conditions in November 2006 allowed us to commence the 2007 Hay River drilling program a month earlier than anticipated in this "winter access only" area. In southeast Saskatchewan, we drilled our first horizontal wells into our new light oil discovery at Kenosee as well as drilled infill horizontal wells at Hazelwood. At Red Earth, our drilling focused on infill and step-out wells in the Slave Point oil pool while at Lloydminster and Suffield, we continued with an infill horizontal drilling program.

The $63.3 million of well equipment, pipelines and facilities expenditures includes approximately $15 million relating to a number of initiatives to improve the efficiency of our Hay River operations. These include the construction of an all season road, the installation of natural gas infrastructure and an electrical distribution system. At Cairo, we incurred $3.1 million completing the construction of gathering, compression and processing facilities to tie in natural gas wells drilled in 2006 with production expected to commence in the second quarter of 2007.

Corporate Acquisition

Effective March 1, 2007 we acquired a private petroleum and natural gas corporation for cash consideration of $30.3 million including $350,000 of estimated acquisition costs. This acquisition added approximately 1,500 bbl/d of western Saskatchewan heavy oil production which is immediately adjacent to our existing operations in the area.

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 petroleum and natural gas segment and this amount is unchanged at March 31, 2007. 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 for changes in the estimated future cash flows of the underlying obligation. Our asset retirement obligation increased by $5.0 million during the three months ended March 31, 2007. This increase is due to additions resulting from the acquisition of a private corporation, drilling activity during the quarter and accretion expense, offset by actual asset retirement expenditures made during the quarter.

REFINING AND MARKETING OPERATIONS

On October 19, 2006, we completed our acquisition of North Atlantic the principal asset of which is a medium gravity sour crude hydrocracking refinery with a 115,000 bbl/d capacity (the "Refinery") and a marketing division with 64 gas stations, a home heating business and a commercial and wholesale petroleum products business, all located in the province of Newfoundland and Labrador. The Refinery is capable of processing a wide range of crude oils and feedstocks with a sulphur content as high as 3.5% and API gravity in the range of 25° to 40° with its product slate weighted towards high quality diesel fuel, jet fuel, and gasoline that are currently compliant with product specifications (including sulphur, cetane and aromatic content). Approximately 10% of North Atlantic's refined products are sold in the province of Newfoundland and Labrador with the balance sold in the U.S. east coast markets, primarily Boston and New York City. Through its marketing division, North Atlantic operates a petroleum marketing and distribution business in the province of Newfoundland and Labrador with average daily sales over 11,000 barrels representing approximately a 15% to 20% share of the market. Effective with the closing of this acquisition on October 19, 2006, the operating results of North Atlantic are included in the operations of Harvest with segmented reporting for each of the petroleum and natural gas operations in western Canada and the refining and marketing business in the province of Newfoundland and Labrador.

The following summarizes the North Atlantic financial and operational information for the three month period ended March 31, 2007 compared to the period from October 19, 2006 to December 31, 2006:

(in 000's of Canadian dollars except as noted below)	**Three Month Period ended March 31, 2007**	**October 19, 2006 to December 31, 2006**
Revenues	**784,045**	**460,359**
Purchased products for resale and processing	**632,296**	**386,014**
Gross Margin(1)	**151,749**	**74,345**
Costs and expenses		
Operating expense	**25,661**	**18,378**
Purchased energy expense	**24,000**	**15,685**
Marketing expense	**7,343**	**5,060**
Depreciation and amortization expense	**19,389**	**15,482**
Operating income(1)	**75,356**	**19,740**
Cash capital expenditures	**4,883**	**21,411**
Feedstock volume (bbl/day)	**113,711**	**86,890**
Yield (000's barrels)		
Gasoline and related products	**3,310**	**1,875**
Ultra low sulphur diesel	**4,213**	**2,624**
Heavy fuel oil	**2,745**	**1,752**
Total	**10,268**	**6,251**

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

Overview of Refining and Marketing Operations

For the three month period ended March 31, 2007, North Atlantic's Operating Income and Cash Flow were robust, reflecting strong refining margins as well as near capacity operating performance with no planned nor unplanned disruptions. As compared to the prior period, North Atlantic's gross margin increased from US$9.32 to US$11.85 per bbl, reflecting the impact of increases in gasoline and heating oil prices, coupled with a slight drop in the WTI price offset by a narrowing of the differential between medium gravity sour crude oil and light sweet crude oil, as well as strengthening prices for heavy fuel oil. North Atlantic's daily throughput averaged 113,711 bbls/d of crude oil and vacuum gas oil for the first quarter of 2007 as compared to 86,890 bbls/d in the period from October 19, 2006 through December 31, 2006 when the refinery operations were impacted by an extended turnaround, an unplanned disruption with its naphtha hydrotreater and a disruption in electric power service.

Refining Benchmark Prices

An oil refinery is a manufacturing facility that uses crude oil and other feedstocks as a raw material and produces a wide variety of refined products. The actual mix of refined products from a particular refinery varies according to the refinery's processing units, the specific refining process utilized and the nature of the crude oil feedstock. The refinery processing units generally perform one of three functions: the different types of hydrocarbons in crude oil are separated, the separated hydrocarbons are converted into more desirable or higher value products, or chemicals treat the products to remove unwanted elements and components such as sulphur, nitrogen and metals. Refined products are typically differing grades of gasoline, diesel fuel, jet fuel, furnace oil and heavier fuel oil.

The refining industry has a few benchmark prices from which to assess a particular refinery's performance. Typically, these benchmarks include prices for refined products such as Reformulated Blendstock for Oxygenate Blending gasoline ("RBOB gasoline") and heating oil. As a benchmark indicator of refining margins, the New York Mercantile Exchange ("NYMEX") "2-1-1 Crack Spread" is a refining benchmark 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 the NYMEX gasoline and NYMEX heating oil prices. The following refining industry benchmark prices are provided as reference points from which to assess the North Atlantic refinery's performance:

	Three Month Period ended March 31, 2007	October 19, 2006 to December 31, 2006
West Texas Intermediate crude oil (US$ per barrel)	**58.16**	**60.44**
RBOB gasoline (US$ per barrel/US$ per gallon)	**70.77/1.69**	**66.78/1.59**
Heating Oil (US$ per barrel/US$ per gallon)	**69.86/1.66**	**71.82/1.71**
2-1-1 Crack Spread (US$ per barrel)	**12.14**	**8.86**
Canadian / U.S. dollar exchange rate	**0.854**	**0.883**

Although the "2-1-1 Crack Spread" is a typical industry benchmark, the North Atlantic refinery differs in that it also produces heavy fuel oil not represented in the "2-1-1 Crack Spread" benchmark and also processes primarily a medium gravity sour crude oil rather than a WTI quality of light sweet crude oil. In addition North Atlantic purchases approximately 8,000 to 10,000 bbl/d of additional vacuum gas oil to optimize the throughput of its hydrocracker (Isomax) unit which is a key unit in the production of gasoline and diesel fuel and this further differentiates the North Atlantic refinery gross margin from the "2-1-1 Crack Spread" benchmark.

North Atlantic's Refinery Feedstock

The cost and volume of North Atlantic's crude oil feedstocks were as follows:

	Three Month period ended March 31, 2007			October 19, 2006 to December 31, 2006		
	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	**422,856**	**7,002**	**51.55**	**305,396**	**5,372**	**50.21**
Hamaca	**96,977**	**1,664**	**49.75**	**28,826**	**524**	**48.59**
Urals	**42,376**	**730**	**49.55**	**-**	**-**	**-**
Crude Oil Feedstock	**562,209**	**9,396**	**51.07**	**334,222**	**5,896**	**50.07**
Vacuum Gas Oil	**57,996**	**838**	**59.06**	**26,645**	**446**	**52.77**
	620,205	**10,234**	**51.73**	**360,867**	**6,342**	**50.26**
Other costs	**(819)**			**6,834**		
	619,386			**367,701**		

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

During the first quarter of 2007, the Refinery feedstock was comprised of 104,400 bbl/d of medium sour crude oil (approximately 74% Basrah Light from Iraq, 18% Hamaca from Venezula and 8% Urals from Russia) and 9,311 bbl/d of vacuum gas oil compared to 80,767 bbl/d of crude oil and 6,100 bbl/d of vacuum gas oil for the prior period. The price of North Atlantic's crude oil feedstock averaged US$51.07 for the three months ended March 31, 2007, an increase of US$1.00 compared to the prior period as a US$3.28 narrowing of differentials between its cost of medium gravity sour crude oil feedstock and the sweet light crude oil benchmark more than offset the US$2.28 drop in the WTI benchmark price. Relative to the average price of the WTI benchmark, the medium gravity sour crude purchased by North Atlantic represents a US$7.09 per barrel price differential for the first quarter of 2007 as compared to US$10.37 in the prior period.

North Atlantic's Refined Products

Product yields are impacted by the crude oil feedstock as well as refinery performance. During the first quarter of 2007, North Atlantic's refined product yield was relatively unchanged with approximately 32% gasoline, 41% ultra low sulphur diesel and jet fuel and 27% heavy fuel oil compared to 30%, 42% and 28%, respectively. A summary of North Atlantic's product yield, pricing and revenue for the three month period ended March 31, 2007 and the prior period are as follows:

	Three Month period ended March 31, 2007			October 19, 2006 to December 31, 2006		
	Refinery Revenues	**Volume**	**Product Price(1)**	**Refinery Revenues**	**Volume**	**Product 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	**273,656**	**3,310**	**70.57/1.68**	**131,643**	**1,875**	**62.01/1.48**
Low & ultra low sulphur diesel & jet fuel	**360,122**	**4,213**	**72.96/1.74**	**216,435**	**2,624**	**72.85/1.73**
Heavy fuel oil	**132,398**	**2,745**	**41.16/0.98**	**78,969**	**1,752**	**39.81/0.95**
	766,176	**10,268**		**427,047**	**6,251**	
Other	**(4,838)**			**7,617**		
	761,338			**434,664**		
Yield (as a % of Feedstock)		**100%**			**99%**	

(1) Product prices are based on the sales at the North Atlantic refinery loading docks.

Relative to the benchmark prices, North Atlantic received US$70.57 per bbl (US$1.68 per gallon) for its gasoline during the first quarter of 2007 as compared to US$1.69 per gallon for NYMEX RBOB gasoline and US$72.96 (US$1.74 per gallon) for its ultra low sulphur diesel and jet fuel products compared to US$1.66 for NYMEX heating oil. During the first quarter of 2007, North Atlantic's gasoline price closely followed the NYMEX reference price (within US$0.01) while its diesel fuel and jet fuel commanded a premium of US$0.08 per gallon over the NYMEX heating oil price reflecting its higher product quality net of shipping costs to the New York harbour.

Relative to the average price we paid for the Basrah feedstock, the selling price of North Atlantic's heavy fuel oil resulted in a negative contribution of US$10.39 per barrel and aggregated to approximately $33.4 million for the three month period ended March 31, 2007 compared to US$10.40 per barrel and $20.6 million in the prior period. The heavy fuel oil produced by North Atlantic presents an opportunity to re-configure the Refinery to produce more gasoline and diesel fuel and in March 2007, we announced North Atlantic's intent to enhance its existing visbreaker unit to more completely upgrade an incremental volume of approximately 1,500 bbl/d of heavy fuel oil into heating oil at an estimated cost of $22 million.

North Atlantic's Gross Margin

North Atlantic's gross margin is comprised 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 the three month period ended March 31, 2007 and from October 19, 2006 to December 31, 2006 are as follows:

	Three Month period ended March 31, 2007			October 19, 2006 to December 31, 2006		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	**Refining**	**Marketing**	**Total**
Sales revenue(1)	**761,337**	**91,290**	**784,045**	**434,665**	**68,099**	**460,359**
Cost of products for processing and resale(1)	**619,386**	**81,492**	**632,296**	**367,701**	**60,718**	**386,014**
Gross margin(2)	**141,951**	**9,798**	**151,749**	**66,964**	**7,381**	**74,345**

(1) The North Atlantic sales revenue and cost of products for processing and resale are net of inter-segment sales of $68,582,000 reflecting the refined products produced by the Refinery Operations and sold by the Marketing Operations for the three month period ended March 31, 2007 ($42,405,000 for the period from October 19, 2006 to December 31, 2006)

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

During the three months ended March 31, 2007, North Atlantic's crack spread of $142.0 million is comprised of $162.6 million of gross margin on the production of gasoline and ultra low sulphur diesel and jet fuel from its crude oil feedstock (including a heavy sour differential of approximately $55.3 million) and $15.8 million on the production of gasoline and ultra low sulphur diesel and jet fuel from purchased VGO offset by a $36.4 million negative contribution from the production of heavy fuel oil and other refined products. This compares to gross margin of $67.0 million comprised of $83.7 million (including $47.4 million of heavy sour differential), $9.7 million and $26.4 million, respectively, for the prior period.

Relative to the industry "2-1-1 Crack Spread" benchmark of US$12.14 during the first quarter of 2007 (US$8.86 for the prior period), North Atlantic's crack spread averaged US$11.85 per barrel of throughput (US$9.32 for the prior period), representing a 27% increase compared to a 37% increase in the "2-1-1 Crack Spread" benchmark. North Atlantic did not fully participate in the "2-1-1 Crack Spread" appreciation as the benefits of processing medium gravity sour crude oil were more than offset by 27% of its production being heavy fuel oil.

The gross margin from North Atlantic's marketing operations of $9.8 million (up $2.4 million from the prior period) is composed 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.

Operating Expenses

A summary of North Atlantic's operating costs for the refinery and marketing operations for the three month period ended March 31, 2007 and from October 19, 2006 to December 31, 2006 are as follows:

	Three Month period ended March 31, 2007			**October 19, 2006 to December 31, 2006**		
(000's of Canadian dollars)	**Refining**	**Marketing**	**Total**	**Refining**	**Marketing**	**Total**
Operating expense	**21,331**	**4,330**	**25,661**	**14,771**	**3,607**	**18,378**
Purchased energy	**24,000**	**-**	**24,000**	**15,685**	**-**	**15,685**
	45,331	**4,330**	**49,661**	**30,456**	**3,607**	**34,063**

The largest component of operating expense is wages and benefits which totaled $14.8 million (approximately 58% of operating expense) while the other significant components were maintenance and repairs costs ($3.4 million), insurance ($1.9 million) and chemicals ($0.8 million) which were all in line with expectations. Other operating expenses are also in line with expectations. Refining operating expenses were $2.08 per barrel during the period which is slightly lower than our expectations of approximately $2.20 to $2.40 per barrel and this is directly attributable to the increased throughput during the quarter.

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 were $2.35 per barrel during the first quarter of 2007 which is slightly higher than our expectations of less than $2.20.

During the first quarter of 2007, marketing expense is comprised of $1.0 million of marketing fees (based on US $0.08 per barrel of feedstock) to acquire feedstock and $6.3 million of "Time Value of Money" charges incurred pursuant to the supply and offtake agreement entered into with Vitol Refining S.A as compared to $0.5 million and $4.6 million, respectively, for the period from October 19, 2006 to December 31, 2006.

Capital Expenditures

During the first quarter of 2007, capital spending totaled $4.9 million and included upgrades to our retail operations, planned maintenance on our feedstock and refined product storage tanks and various sustaining capital and improvement projects.

Depreciation and Amortization Expense

North Atlantic's depreciation and amortization expense for the refinery and marketing operations for the three month period ended March 31, 2007 and from October 19, 2006 to December 31, 2006 is as follows:

	Three Month period ended March 31, 2007			October 19, 2006 to December 31, 2006		
(000's of Canadian dollars)	Refining	Marketing	Total	Refining	Marketing	Total
Tangible assets	**17,183**	**495**	**17,678**	**13,832**	**411**	**14,243**
Intangible assets	**1,304**	**407**	**1,711**	**1,050**	**189**	**1,239**
	18,487	**902**	**19,389**	**14,882**	**600**	**15,482**

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. No charge for impairment of this goodwill has been made.

FINANCING AND OTHER

Interest Expense

	Three Months ended March 31		
(000s)	**2007**	2006	Change
Interest on short term debt			
Bank loan	**$ 1,170**	$ 150	680%
Convertible debentures	**646**	-	100%
Amortization of deferred finance charges – short term debt	**1,811**	-	100%
	3,627	150	2,318%
Interest on long-term debt			
Bank loan	**19,176**	1,303	1,372%
Convertible debentures	**14,448**	3,296	338%
$7^{7/8}$% Senior Notes	**6,146**	5,724	7%
Amortization of deferred finance charges – long term debt	**679**	1,434	(53%)
	40,449	11,757	244%
Total interest expense	**$ 44,076**	$ 11,907	270%

Interest expense, which includes the amortization of related financing costs, was $32.2 million higher for the three month period ended March 31, 2007 than in the prior year. Of this increase, $18.9 million is due to bank loan interest (both short term and long term) resulting from the significant increase in the drawn amounts on our credit facilities and $11.8 million is related to the $599.7 million increase in the amount of convertible debentures outstanding, both of which were used to finance the acquisition of North Atlantic, and to a lesser extent, the acquisition of Birchill.

During the first quarter of 2007, our short term bank debt consisted of the $289.7 million outstanding under our Senior Secured Bridge Facility which was fully repaid on February 1, 2007 with the net proceeds from our issuance of 6,146,750 trust units and $230 million principal amount of 7.25% Debentures due 2014. The early repayment has also accelerated our expensing of $1.7 million of unamortized commitment fees related to this facility. The interest on the long term portion of our bank loans relates to the interest charges on our Three Year Extendible Revolving Facility at a floating rate based on 75 basis points over bankers' acceptances for Canadian dollar borrowings and 75 basis points over the London Inter Bank Order

Rate for US dollar borrowings. Further details on our credit facilities and the bridge financing are included under "Liquidity and Capital Resources".

The interest on our convertible debentures totaled $15.1 million during the first quarter of 2007 and is based on the effective yield of the debt component of the convertible debentures. The details of the $851.9 million of convertible debentures outstanding are fully described in Note 11 to the interim consolidated financial statements for the three month period ended March 31, 2007 filed on SEDAR at www.sedar.com. During the quarter, there were $230 million principal amount of 7.25% Debentures due 2014 issued and an aggregate of $333,000 principal amount of convertible debentures converted to trust units.

Included in short and long term interest expense is the amortization of the discount on the 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 $2.5 million for the three months ended March 31, 2007. This $1.1 million increase over the $1.4 million expensed in 2006 is mainly due to the amortization of the commitment fees on the credit facility negotiated in 2006.

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, $7^{7/8}$% Senior Notes as well as any other U.S. dollar cash balances. Since December 31, 2006, the Canadian dollar has strengthened slightly as compared to the U.S dollar. As a result we incurred an unrealized gain on our senior notes of $2.7 million. In connection with the purchase of North Atlantic, we have maintained approximately US$650 million of bank debt which contributed a further $7.1 million to the unrealized foreign exchange gains for the three month period ended March 31, 2007. In addition, we also incurred $0.8 million of unrealized foreign exchange gains on transactions incurred by North Atlantic and realized gains of $0.1 million.

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

On October 31, 2006, the Government of Canada announced plans to introduce a tax on publicly traded income trusts. For existing income trusts, the new tax measures would be effective for 2011, provided we comply with the "normal growth" parameters regarding equity growth until that time. A "Notice of Ways and Means Motion" was passed in Parliament shortly after the government announcement. This notice was a summary of the government's proposal and did not specify the particular amendments to the Income Tax Act.

On December 15, 2006, the government announced safe harbour guidance regarding "normal growth." The safe harbour amount will be measured by reference to the trust's market capitalization as of the end of trading on October 31, 2006 (which was approximately $3.7 billion for Harvest). For the period from November 1, 2006 to December 31, 2007 a trust's safe harbour amount will be 40% of the October 31, 2006 market capitalization benchmark and for each of the years 2008 through to and including 2010 will be 20% of the benchmark. In addition, we understand that trusts will be able to issue equity to retire debt existing on October 31, 2006 without eroding their safe harbour limits.

Should the tax legislation become substantively enacted, future income taxes may be adjusted to include temporary differences between the accounting and tax bases of the Trust's assets and liabilities. In addition, reserves reported under National Instrument 51-101 may be adjusted to include an estimate of the tax effect on our estimated future revenues from our reserves. We will assess alternative organizational structures during the four-year transition period, however, we are confident that regardless of the final tax legislation or our structure we will continue to provide value to our unitholders. As of March 31, 2007, this proposed tax legislation has not been substantively enacted and accordingly, no such adjustments have been made to our interim consolidated financial statements for the three months ended March 31, 2007.

During 2006, we have integrated Viking and Birchill into the Harvest organization in such a fashion that much of the value of these acquisitions is attributed to the net profits interests on the respective petroleum and natural gas properties created subsequent to their acquisition. The value of the net profits interest resides within the Trust while the tax basis associated with these acquisitions is retained by our corporate entities. The net result of this approach to integration for income tax purposes is that the book basis and the tax basis of our petroleum and natural gas assets held in corporate entities are approximately equal resulting in no recorded future income taxes beyond the recovery of $2.3 million in the prior year.

Contractual Obligations and Commitments

We have contractual obligations and commitments 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	**1,651,872**	-	65,000	1,586,872	-
Interest on long-term debt(4)	**257,202**	74,907	141,628	40,667	-
Interest on convertible debentures(3)	**368,497**	45,672	116,329	113,197	93,299
Operating and premise leases	**18,117**	4,715	10,729	2,415	258
Capital commitments(5)	**14,165**	11,285	2,880	-	-
Asset retirement obligations(6)	**698,475**	10,628	13,058	13,321	661,468
Transportation (7)	**4,099**	1,498	2,345	256	-
Purchase commitments	**9,327**	9,327	-	-	-
Pension contributions	**27,882**	585	3,345	4,805	19,147
Feedstock commitments	**798,497**	791,720	6,777	-	-
Total	**3,848,133**	950,337	362,091	1,761,533	774,172

(1) As at March 31, 2007, we had entered into physical and financial contracts for production with average deliveries of approximately 26,655 barrels of oil equivalent per day for the remainder of 2007, and 10,000 barrels of oil equivalent per day in 2008. We have also entered into financial contracts to minimize our exposure to fluctuating electricity prices. Please see Note 15 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.
(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.

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 three month period ended March 31, 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 month period ended March 31, 2007 with the most significant difference being that the deferred charges previously presented as an asset are now netted against the respective debt giving rise to the charges. 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 month period ended March 31, 2007.

LIQUIDITY AND CAPITAL RESOURCES

At the end of March 2007, we had total debt and equity of $5,730.9 million, an increase of $174.7 million compared to $5,556.2 million at the end of December 2006. During the first quarter of 2007, the significant changes to our capital structure were:

- The issuance of $230 million principal amount of Convertible Unsecured Subordinated Debentures and 6,146,750 trust units with net proceeds of $357.4 million that were applied to fully repay the Senior Secured Bridge Facility with the remaining $67.7 million applied to reduce the drawn amount of our Three Year Extendible Revolving Credit Facility, and
- The issuance of 1,802,681 trust units pursuant to Harvest's Premium Distribution™, Distribution Reinvestment and Optional trust unit Purchase Plan (the "DRIP Plans") raising $43.8 million.

(in millions)	**March 31, 2007**	December 31, 2006
DEBT		
Credit Facilities		
- Three Year Extendible Revolving Credit Facility	**$1,363.2**	$1,306.0
- Senior Secured Bridge Facility	-	289.7
Total Bank Debt	**1,363.2**	1,595.7
$7^{7/8}$ % Senior Notes Due 2011 (US$250 million) [1]	**288.7**	291.4
Convertible Debentures, at principal amount		
10.5% Debentures Due 2008	**26.6**	26.6
9% Debentures Due 2009	**1.1**	1.2
8% Debentures Due 2009	**2.1**	2.2
6.5% Debentures Due 2010	**37.9**	37.9
6.4% Debentures Due 2012	**174.7**	174.8
7.25% Debentures Due 2013	**379.5**	379.5
7.25% Debentures Due 2014	**230.0**	-
Total Convertible Debentures	**851.9**	622.2
Total Debt	**2,503.8**	2,509.3
TRUST UNITS		
130,072,293 issued at March 31, 2007	**3,227.1**	
122,096,172 issued at December 31, 2006		3,046.9
TOTAL DEBT AND TRUST UNITS	**$5,730.9**	$5,556.2

[1] Face value converted at the period end exchange rate.

During the three month period ended March 31, 2007, our Cash Flow totaled $213.9 million and we declared distributions to our Unitholders aggregating to $145.3 million ($43.8 million of which was reinvested through our distribution reinvestment plans) resulting in $112.4 million retained for our capital programs. During the first quarter of 2007, our capital spending aggregated to $153.4 million with $112.4 million funded from Cash Flow and the residual funded with our credit lines. This compares with Cash Flow of $101.0 million ($95.9 million after including $5.1 million of one time cash transaction costs relating to the acquisition of Viking) and distributions declared of $94.8 million, net of $29.9 million reinvested through our distribution reinvestment plans in the prior year.

Management, together with the Board of Directors of Harvest, continually assess distributions relative to cash flow projections, debt leverage and capital spending plans. On April 11, 2007 we announced the declaration of a $0.38 per trust unit distribution for each of April, May and June 2007 based on forecasted commodity price levels and operating performance that are consistent with the current environment. Of the distributions declared for the first three months of 2007 totaling $145.3 million and representing 68% of Cash Flow, $43.8 million have been settled with trust units as a result of Unitholders choosing to participate in our distribution reinvestment plans, representing a participation rate of approximately 30%.

In February 2007, we issued 6,146,750 trust units and $230 million principal amount of 7.25% Debentures due 2014 for net proceeds of $357.4 million and applied these proceeds to fully repay the remaining balance outstanding on the Senior Unsecured Bridge Facility with the residual $67.7 million of proceeds applied to the $1.4 billion Three Year Extendible Revolving Facility thereby increasing our undrawn credit capacity.

As anticipated, we requested that our lenders extend the maturity date of our Three Year Extendible Revolving Credit Facility to April 2010 from March 2009 and approve the expansion of the facility from $1.4 billion to $1.6 billion. All lenders approved the expansion of the facility to $1.6 billion and we have received consents to extend the maturity date to April 2010 from lenders representing $1,535 million of commitments with one lender representing a $65 million commitment not consenting to an extension of the maturity date. Accordingly, our Three Year Extendible Revolving Credit Facility now consists of $1,535 million maturing April 2010 and $65 million maturing March 2009. For a complete description of this 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 depending on our secured senior debt (excluding, $7^{7/8}$% Senior Notes and convertible debentures) to earnings before interest, taxes, depletion, amortization and other non-cash amounts ("EBITDA") with availability under this facility subject to:

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

At the end of March 31, 2007, our Bank Debt to annualized first quarter Cash Flow ratio was 1.6 to 1.0, Total Debt (excluding convertible debentures) to annualized first quarter Cash Flow was 1.9 to 1.0 while the Bank Debt to Total Capitalization was 24% and Total Debt to Total Capitalization was 44%.

Concurrent with the closing of the North Atlantic acquisition, North Atlantic entered into a Supply and Offtake Agreement with Vitol Refining S.A., a third party related to the vendor of North Atlantic, that during the term of the agreement, provides for the ownership of substantially all of the crude oil feedstock and refined product inventory at the Refinery be retained by Vitol Refining S.A. and that Vitol Refining S.A. will be granted the right and obligation to provide crude oil feedstock with delivery to the Refinery as well as the right and obligation to purchase all refined products produced by the Refinery. In addition to assisting North Atlantic by procuring the crude oil feedstock and marketing the refined products, this agreement also significantly reduces North Atlantic's working capital commitments by eliminating the requirement for North Atlantic:

- to post letters of credit for crude oil feedstock purchase commitments,
- to arrange for the shipping of crude oil feedstock to the Refinery,
- to pay for crude oil feedstock purchases while in-transit to and in tankage at the Refinery,

- to finance the receivables from the sale of refined products, and
- to arrange for the shipping of refined products to customers.

In respect of this working capital requirement assumed by Vitol Refining S.A., the Supply and Offtake Agreement provides that North Atlantic will pay a "Time Value of Money" charge reflecting an effective interest rate of 350 basis points over the London Inter Bank Offer Rate. The Supply and Offtake Agreement may be terminated by either party at the end of the initial two year term (October 2009), and at any time thereafter by providing notice of termination no later than six months prior to the desired termination date. The potential for termination of the Supply and Offtake Agreement requires that we maintain the financial flexibility to provide the working capital capacity currently provided by Vitol Refining S.A. as well as either develop the internal capability to perform these supply services or identify and negotiate a similar contract with another provider of such services. At the end of March 31, 2007, we estimate that the outstanding commitments under the Supply and Offtake Agreement aggregated to approximately $798.5 million.

Following the October 31, 2006 announcement by the Government of Canada which proposed to apply a 31.5% tax on the distributions from certain publicly traded mutual funds including Harvest Energy Trust, the trading value of our trust units (which closed on October 31, 2006 at $32.95) has been as follows:

	Trading Price		
Month	**High**	**Low**	**Volume**
TSX Trading			
November 2006	$ 28.60	$ 24.76	2,903.180
December 2006	$ 26.88	$ 25.70	8,828,206
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
NYSE Trading (in US$)			
November 2006	$ 25.29	$ 22.05	34,223,300
December 2006	$ 23.43	$ 22.27	16,264,800
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

Following the October 31, 2006 announcement, the trading value of our trust units sustained a significant drop in trading range and only now is returning to within 10% of its pre-announcement levels on the strength of rising commodity prices, narrowing oil quality differentials and robust refining margins. Maintaining the strength in the trading value of our trust units is critical as our trust units are the currency that enables us to optimize the accretive value of transactions including our anticipated participation in the expected consolidation of the Canadian energy royalty trust sector as well as minimizing the dilutive impact of issuing trust units to repay our debt.

Disclosure of Outstanding Trust Unit Data

We are authorized to issue an unlimited number of trust units. As at May 8, 2007, we had 130,634,164 trust units outstanding, 3,741,375 of Unit Appreciation Rights outstanding (of which 576,100 are exercisable) and 308,475 awards issued under the Unit Awards Incentive Plan (of which 106,848 were exercisable). In addition, we had seven series of convertible debentures outstanding that are convertible into 26,367,959 trust units.

Distributions to Unitholders and Taxability

In the three month period ended March 31, 2007, we declared monthly distributions of $0.38 per trust unit ($145.3 million) to Unitholders, 68% of our Cash Flow, and have declared a monthly distribution of $0.38 per trust unit for the second quarter of 2007 as well. The $50.5 million increase in distributions declared during the first three months of 2007 as compared to $94.8 million in the prior year is primarily due to an increase of 29,525,764 trust units outstanding following the acquisitions of

Viking, Birchill and North Atlantic in 2006 (limited to an additional one month with respect to the Viking acquisition) along with issuance under our distribution re-investment plans.

	Three Month Period ended March 31		
(000s except per trust unit amounts)	**2007**	2006	Change
Distributions declared	**$ 145,270**	$ 94,812	53%
Per trust unit	**$ 1.14**	$ 1.11	3%
Taxability of distributions	**100%**	100%	-
Payout ratio(1)	**68%**	94%	(26%)

(1) Cash flow used to calculate payout ratio excludes working capital changes, settlements of asset retirement obligations and in 2006, one time transaction costs associated with the Viking acquisition - see "Non-GAAP Measures".

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 no have taxable income.

OUTLOOK

During the first quarter of 2007, we benefited from robust refining margins and a significant narrowing of differentials between the WTI benchmark price and light to medium oil and heavy oil prices in western Canada. While we do not attempt to forecast commodity prices nor forecast Cash Flow or the level of cash distributions, strong refining margins and the narrowing of product quality differentials have continued into the second quarter.

In assessing our guidance for the balance of 2007, we continue to anticipate daily production to average 66,000 boe/d for the balance of 2007 but are adjusting our operating cost expectations to a range $11.00 to $11.50 per boe for our petroleum and natural gas operations with our annual capital expenditures unchanged at $295 million. For our refining and marketing business, we are maintaining our annual throughput expectations of 111,400 bbls/d of feedstock (excluding purchased fuel oil consumed by the plant) and are shifting our unit operating cost estimate to the higher end of our $4.40 to $4.60 range with capital spending unchanged at $60 million with approximately $30 million invested in maintenance capital and discretionary capital spending ranging from $15 million to $30 million for a visbreaker unit upgrade as well as other discretionary projects. With our Cash Flow in 2007 expected to increase with the Refinery acquisition and increases in the floor prices of our oil price risk management contracts and assuming a $0.38 per trust unit monthly distribution level, we anticipate a reduction in our 2007 payout ratio.

Currently, we have entered into price risk management contracts to provide a floor price of US$55.67 (relative to the West Texas Intermediate benchmark price) with upside participation on prices above US$55.67 for 26,655 bbls/d for the balance of 2007. After considering our 19% average royalty rate, these risk management contracts reduce our WTI price risk exposure at prices under US$55.67 to 25% of our crude oil production. This significantly reduces the volatility of our cash flows to WTI prices if prices trend below the US$55.67 level. To complement these price risk management contracts, we have forward sold US$8,750,000 per month at an average Canadian to US dollar exchange rate of approximately US$0.89 per Canadian dollar through December 2007 and a further US$8,333,000 per month at US$0.90 per Canadian dollar for the first half of 2008, which represents approximately 20% of the US dollar value of the crude oil price risk management contracts.

For the balance of 2007, we have entered into natural gas price contracts that provide the following three way price structure on 30,000 GJ/d for the period from April 2007 through March 2008:

For market prices below $5, a price equal to the market price plus $2;
For market prices between $5 and $7, a fixed price of $7;
For market prices between $7 and $10.27, market prices; and,
For market prices higher than $10.27, a price of $10.27.

After considering an 18% average royalty rate, these contracts reduce our AECO natural gas price exposure at prices less than $7 to 55% of our expected natural gas production. We may add a further 20,000 GJ/d of natural gas price protection.

We have also entered into contracts to fix the price of 35 megawatthours (or approximately 50% of the anticipated electrical consumption of our petroleum and natural gas operations in Alberta) through to the end of December 2008 at a price of $56.69. Our objective with these fixed price contracts is to substantially reduce the volatility of our operating costs to fluctuations in the cost of electricity which represent approximately 25% of the operating costs in our petroleum and natural gas operations.

In assessing our future cash flow risk management (including the impact of our acquisition of North Atlantic), we have concluded that the contracting for price protection on refined products, rather than the crude oil price, will most likely better serve our efforts to add stability to our future cash flows. Accordingly, we will commence contracting for refined product price protection and will also continue to contract for protection on AECO natural gas prices as well as fix the currency exchange rate for US dollars to Canadian dollars along with a measured approach to negotiating fixed prices for electricity. Our objective of these cash flow risk management initiatives is to add stability to our future cash flows to fund long term sustainable cash distributions in a wide variety of pricing environments.

Our growth strategies for the petroleum and natural gas operations in western Canada will be to continue to acquire properties adjacent to our existing operations on favourable terms as well as develop our extensive resource position with capital spending of $295 million planned for 2007. In addition, we intend to be an active participant in the consolidation of Canadian energy royalty trusts which is dependent on the currency value of our trust units as trust-on-trust mergers are expected to be negotiated based on market valuations.

Following the announcement on October 31, 2006 to apply a 31.5% tax at the mutual fund trust level on distributions of certain income from publicly traded mutual fund trusts including Harvest Energy Trust, we continue to monitor related developments but continue to wait for firm guidelines and the details of the proposed legislation. As of March 31, 2007, we estimate that 58% of our Unitholders are non-Canadian residents, an increase of 4% since December 31, 2006 and a significant increase since February 2006 when non-Canadian residents owned 33%. As the taxation of publicly traded mutual fund trusts unfolds, we continue to search and validate the most efficient capital structure for our Unitholders balancing the benefits of the remaining four years of tax efficient distributions against the longer term benefits of continuing with a growth strategy beyond the announced “normal growth” limitations.

The following table reflects the sensitivity of our expected Cash Flow for the last nine months of 2007 to changes in the following key factors to our business:

	Assumption	Change	Impact on Cash Flow
WTI oil price (US$/bbl)	$ 60.00	$ 5.00	$ 0.57 / Unit
CAD/USD exchange rate	$ 0.90	$ 0.02	$ 0.14 / Unit
AECO daily natural gas price	$ 7.00	$ 1.00	$ 0.20 / Unit
Refinery crack spread (US$/bbl)	$ 9.30	$ 1.00	$ 0.27 / Unit
Operating Expenses (per boe)	$ 11.25	$ 1.00	$ 0.14 / Unit

SUMMARY OF QUARTERLY RESULTS

The table and discussion below highlight our first quarter 2007 performance over the preceding seven quarters on select measures.

	2007	2006				2005		
(000s except where noted)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Revenue, net of royalties	**$ 1,025,512**	$ 682,744	$ 259,818	$ 257,103	$ 181,160	$ 154,646	$ 169,654	$ 120,263
Net income (loss)	**$ 69,850**	$ 1,533	$ 107,768	$ 60,682	$ (33,937)	$ 75,638	$ 52,862	$ 19,516
Per trust unit, basic[2]	**$ 0.55**	$ 0.01	$ 1.01	$ 0.60	$ (0.41)	$ 1.45	$ 1.09	$ 0.45
Per trust unit, diluted[2]	**$ 0.55**	$ 0.01	$ 0.99	$ 0.60	$ (0.41)	$ 1.42	$ 1.08	$ 0.44
Cash Flow[1]	**$ 213,941**	$ 156,270	$ 147,471	$ 147,010	$ 100,971	$ 96,431	$ 103,508	$ 57,217
Per trust unit, basic[1]	**$ 1.68**	$ 1.35	$ 1.39	$ 1.45	$ 1.23	$ 1.84	$ 2.14	$ 1.32
Per trust unit, diluted[1]	**$ 1.52**	$ 1.29	$ 1.34	$ 1.43	$ 1.22	$ 1.81	$ 2.09	$ 1.29
Distributions per Unit, declared	**$ 1.14**	$ 1.14	$ 1.14	$ 1.14	$ 1.11	$ 1.05	$ 0.95	$ 0.60
Total long term financial liabilities	**$ 2,436,018**	$ 2,478,518	$ 1,105,728	$ 746,840	$ 735,896	$ 349,074	$ 386,124	$ 455,163
Total assets	**$ 5,800,346**	$ 5,745,558	$ 4,076,771	$ 3,455,918	$ 3,470,653	$ 1,308,481	$ 1,327,272	$1,117,792

(1) This is a non-GAAP measure as referred to under "Non-GAAP Measures".

(2) 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 2005, net revenues increased due to the higher production from our Hay River acquisition in August 2005, stronger crude oil prices and narrower heavy oil differentials which did not continue into the fourth quarter of 2005. The growth in cash flows is closely aligned with the growth in net revenues and is attributed to the same factors as is the growth in net revenues.

Net income reflects both cash and non-cash items. Changes in non-cash items, including DDA&A expense, unrealized foreign exchange gains and losses, unrealized gains and losses on risk management contracts, trust unit right compensation expense and future income taxes cause net income to vary significantly from period to period. The main reason for 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 Flow.

Growth in total assets over the last eight quarters is directly attributed to our acquisition of the Hay River assets in the third quarter of 2005, 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 Flows 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.

The estimates in reserves impact many of our accounting estimates including our depletion calculation. A decrease of reserves by 10% would result in an increase of approximately $70 million in our depletion expense.

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 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 related to 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 ratified a strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards over a transitional period. The Accounting Standards Board ("AcSB") is expected to develop and publish a detailed implementation plan with a transition period expected to be approximately five years. 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. Accordingly, it would be 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, Canada's Accounting Standards Board 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, Canada's Accounting Standards Board 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.

Accounting changes

The AcSB issued CICA Section 1506, *Accounting Changes*. The standard prescribes the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies and estimates, and correction of errors. The standard requires the retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impractical to determine either the period-specific effects or the cumulative effect of the change. Application is on a prospective basis and is effective for changes in accounting policies and estimates and correction of errors made in fiscal years beginning on or after January 1, 2007.

Variable Interest Entities

The Emerging Issues Committee (EIC) issued EIC Abstract 163 – *Determining the Variability to be Considered in Applying AcG 15*. This Abstract, which is harmonized with the equivalent United States FASB Staff Position (FSP) FIN 46(R) – 6 – *Determining the Variability to be Considered in Applying FASB Interpretation No. 46(R)*, provides guidance on how an enterprise should determine the variability to be considered in applying *AcG 15 – Consolidation of Variable Interest Entities*. The Abstract is to be applied prospectively to all entities with which an enterprise first becomes involved and to all entities previously required to be analyzed under AcG 15 when a reconsideration event has occurred beginning the first day of the first reporting period beginning on or after January 1, 2007.

OPERATIONAL AND OTHER BUSINESS RISKS

Our financial and operating performance is subject to risks and uncertainties which include, but are not limited to: oil and natural gas operations, refinery and petroleum marketing 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
- Remunerating employees with a combination of average industry salary and benefits combined with a merit based bonus plan to reward success in execution of our business plan.

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, particularly a new leader for our refinery operations to replace the current President, Refinery Manager of North Atlantic who has committed to an orderly transition.

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 a low 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 has 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. A final report with recommendations is expected to be presented to the Government of Alberta by August 31, 2007. It would be premature to assess the impact of the initiative, if any, on our financial statements at this time.

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. Specifically, we use Cash Flow as cash flow from operating activities before changes in non-cash working capital, settlement of asset retirement obligations and one time transaction costs. Cash Flow as presented is not intended to represent an alternative to net earnings, cash flow from operating activities or other measures of financial performance calculated in accordance with Canadian GAAP. Management uses Cash Flow to analyze operating performance and leverage. Payout Ratio, Cash G&A and Operating Netbacks are additional non-GAAP measures used extensively in the Canadian energy trust sector for comparative purposes. Payout Ratio is the ratio of distributions to total Cash Flow. 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. Cash G&A are G&A expenses excluding the effect of our unit based compensation plans. Gross Margin is commonly used in the refining industry to reflect the net cash 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. Operating income and operating cash flow are also commonly used in the petroleum and natural gas and refining industries to reflect operating results and cash flows before items not directly related to operations.

For the three months ended March 31, 2007 and 2006, Cash Flows are reconciled to its closest GAAP measure, Cash Flow from operating activities, as follows:

	Three months ended March 31	
(000s)	**2007**	2006
Cash Flow	**$ 213,941**	$ 100,971
Cash Viking transaction costs	**-**	(5,072)
Settlement of asset retirement obligations	**(2,120)**	(1,118)
Changes in non-cash working capital	**(100,773)**	(6,617)
Cash flow from operating activities	**$ 111,048**	$ 88,164

Forward-Looking Information

This MD&A highlights significant business results and statistics from our consolidated financial statements for the three months ended March 31, 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, commodity price risk management activity, acquisitions and dispositions, capital spending, reserve estimates, distributions, access to credit facilities, capital taxes, income taxes, Cash Flow From Operations 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 or 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)

		March 31, 2007		December 31, 2006
Assets				
Current assets				
Cash	**$**	**-**	$	10,006
Accounts receivable and other		**306,561**		257,131
Fair value of risk management contracts *[Note 15]*		**7,981**		17,914
Prepaid expenses and deposits		**14,055**		12,713
Inventories *[Note 4]*		**40,961**		30,512
		369,558		328,276
Deferred charges and other non-current assets *[Note 7]*		**-**		25,067
Fair value of risk management contracts *[Note 15]*		**9,614**		9,843
Property, plant and equipment *[Notes 3 and 5]*		**4,439,592**		4,393,832
Intangible assets *[Note 6]*		**117,350**		122,362
Goodwill		**864,232**		866,178
	$	**5,800,346**	$	5,745,558
Liabilities and Unitholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities *[Note 8]*	**$**	**286,751**	$	294,582
Cash distribution payable		**49,427**		46,397
Current portion of convertible debentures *[Note 11]*		**26,777**		-
Fair value deficiency of risk management contracts *[Note 15]*		**30,050**		26,764
		393,005		367,743
Bank loan *[Note 10]*		**1,363,222**		1,595,663
$7^{7/8}$% Senior notes		**279,612**		291,350
Convertible debentures *[Note 11]*		**766,407**		601,511
Fair value deficiency of risk management contracts *[Note 15]*		**3,557**		2,885
Asset retirement obligation *[Note 9]*		**207,503**		202,480
Employee future benefits *[Note 14]*		**12,223**		12,227
Deferred credit		**741**		794
Unitholders' equity				
Unitholders' capital *[Note 12]*		**3,227,127**		3,046,876
Equity component of convertible debentures		**49,164**		36,070
Accumulated income		**342,391**		271,155
Accumulated distributions		**(875,339)**		(730,069)
Accumulated other comprehensive income *[Note 2]*		**30,733**		46,873
		2,774,076		2,670,905
	$	**5,800,346**	$	5,745,558

Commitments, contingencies and guarantees [Note 18]
Subsequent events [Note 19]
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 (LOSS) AND COMPREHENSIVE INCOME (LOSS) (UNAUDITED)

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

		Three months ended March 31, 2007		Three months ended March 31, 2006
Revenue				
Petroleum, natural gas, and refined product sales	**$**	**1,075,161**	$	224,275
Royalty expense		**(49,649)**		(43,115)
Risk management contracts				
Realized net losses		**(297)**		(8,731)
Unrealized net losses		**(14,121)**		(40,997)
		1,011,094		131,432
Expenses				
Purchased products for processing and resale		**632,296**		-
Operating		**121,957**		50,094
Transportation and marketing		**10,155**		1,623
General and administrative *[Note 13]*		**10,104**		5,812
Transaction costs		**-**		11,742
Interest and other financing charges on short term debt, net		**3,627**		150
Interest and other financing charges on long term debt		**40,449**		11,757
Depletion, depreciation, amortization and accretion		**133,792**		85,325
Foreign exchange loss (gain)		**(11,260)**		908
Large corporations tax and other tax		**124**		338
Future income tax recovery		**-**		(2,300)
Non-controlling interest		**-**		(80)
		941,244		165,369
Net income (loss) for the period	$	**69,850**	$	(33,937)
Cumulative Translation Adjustment		**(16,140)**		-
Comprehensive income (loss) for the period *[Note 2]*	$	**53,710**	$	(33,937)
Net income (loss) per trust unit, basic *[Note 12]*	**$**	**0.55**	$	(0.41)
Net income (loss) per trust unit, diluted *[Note 12]*	**$**	**0.55**	$	(0.41)

See accompanying notes to these consolidated financial statements, including Note 16 respecting the segmented reporting of our petroleum and natural gas operations and refining and marketing activities.

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY (UNAUDITED)

(thousands of Canadian dollars)

	Unitholders' Capital	Equity Component of Convertible Debentures	Accumulated Income	Accumulated Distributions	Accumulated Other Comprehensive Income (AOCI) (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
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	217	-	-	-	-	217
8% Debentures Due 2009	578	(4)	-	-	-	574
6.5% Debentures Due 2010	2,748	(173)	-	-	-	2,575
10.5% Debentures Due 2008	1,620	(336)	-	-	-	1,284
6.40% Debentures Due 2012	21	(2)	-	-	-	19
Exchangeable share retraction	2,648	-	-	-	-	2,648
Exercise of unit appreciation rights and other	8,840	-	-	-	-	8,840
Issue costs	(437)	-	-	-	-	(437)
Net income (loss)	-	-	(33,937)	-	-	(33,937)
Distributions and distribution reinvestment plan	29,917	-	-	(94,812)	-	(64,895)
At March 31, 2006	**$2,431,595**	**$ 26,247**	**$ 101,728**	**$ (356,094)**	**$ -**	**$ 2,203,476**
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
Equity component of convertible debenture issuances						
7.25% Debentures Due 2014	-	13,100	-	-	-	13,100
Convertible debenture conversions						
9% Debentures Due 2009	101	-	-	-	-	101
8% Debentures Due 2009	173	(2)	-	-	-	171
6.5% Debentures Due 2010	-	-	-	-	-	-
10.5% Debentures Due 2008	-	-	-	-	-	-
6.40% Debentures Due 2012	52	(4)	-	-	-	48
Exercise of unit appreciation rights and other	184	-	-	-	-	184
Issue costs	(7,841)	-	-	-	-	(7,841)
Change in AOCI related to foreign currency translation adjustment	-	-	-	-	(16,140)	(16,140)
Net income	-	-	69,850	-	-	69,850
Distributions and distribution reinvestment plan	43,797	-	-	(145,270)	-	(101,473)
At March 31, 2007	**$3,227,127**	**$ 49,164**	**$ 342,391**	**$ (875,339)**	**$ 30,733**	**$ 2,774,076**

See accompanying Notes to these Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(thousands of Canadian dollars)

		Three months ended March 31, 2007		Three months ended March 31, 2006
Cash provided by (used in)				
Operating Activities				
Net income (loss) for the period	**$**	**69,850**	$	(33,937)
Items not requiring cash				
Depletion, depreciation, amortization and accretion		**133,792**		85,325
Unrealized foreign exchange loss (gain)		**(10,736)**		914
Non-cash interest expense		**1,892**		-
Amortization of finance charges		**2,481**		1,727
Unrealized loss on risk management contracts *[Note 15]*		**14,121**		40,997
Future income tax recovery		**-**		(2,300)
Non-controlling interest		**-**		(80)
Unit based compensation expense		**2,430**		3,216
Amortization of office lease premiums and deferred rent expense		**3**		37
Employee benefit obligation		**108**		-
Settlement of asset retirement obligations *[Note 9]*		**(2,120)**		(1,118)
Change in non-cash working capital *[Note 17]*		**(100,773)**		(6,617)
		111,048		88,164
Financing Activities				
Issue of Trust Units, net of issue costs		**136,016**		(68)
Issue of convertible debentures, net of issue costs *[Note 11]*		**220,489**		-
Bank borrowings, net *[Note 10]*		**(225,371)**		81,536
Financing costs		**(273)**		(165)
Cash distributions		**(98,442)**		(45,241)
Change in non-cash working capital *[Note 17]*		**6,202**		(13,301)
		38,621		22,761
Investing Activities				
Additions to property, plant and equipment		**(153,370)**		(103,239)
Business acquisitions		**(30,264)**		-
Property acquisitions		**(3,111)**		(23,382)
Property dispositions		**2,422**		-
Change in non-cash working capital *[Note 17]*		**24,003**		15,696
		(160,320)		(110,925)
Change in cash and cash equivalents		**(10,651)**		-
Effect of exchange rate changes on cash		**645**		-
Cash and cash equivalents, beginning of period		**10,006**		-
Cash and cash equivalents, end of period	**$**	**-**	$	-
Interest paid	**$**	**15,843**	$	2,572
Large corporation tax and other tax paid	**$**	**124**	$	606

See accompanying notes to these consolidated financial statements.

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
Period ended March 31, 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 and 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/losses recognized in other comprehensive income. Held-to-maturity, 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 live 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 these standards; therefore, our prior period financial statements have not been restated. 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 is 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 amounts 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 15 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 refining and marketing 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

On March 1, 2007, Harvest acquired all of the issued and outstanding shares of a private petroleum and natural gas corporation for $30.3 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 on March 1, 2007. 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

		March 31, 2007		December 31, 2006
Petroleum products	**$**	**30,000**	$	19,513
Parts and supplies		**10,961**		10,999
Total inventories, net	**$**	**40,961**	$	30,512

For the periods ended March 31, 2007 and December 31, 2006, inventory included valuation adjustments to the lower of cost or market of $0.6 million and $0.3 million, respectively, and these adjustments were included in "purchased products for resale and processing".

5. Property, Plant and Equipment

	March 31, 2007						December 31, 2006	
		Petroleum and natural gas		Refining and marketing		**Total**		Total
Cost	**$**	**3,981,413**	**$**	**1,306,618**	**$**	**5,288,031**	$	5,115,032
Accumulated depletion and depreciation		**(816,497)**		**(31,942)**		**(848,439)**		(721,200)
Net book value	**$**	**3,164,916**	**$**	**1,274,676**	**$**	**4,439,592**	$	4,393,832

General and administrative costs of $2.7 million (2006 – $3.9 million) have been capitalized during the period ended March 31, 2007, of which $0.5 million (2006 - $2.1 million) relate to the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan.

6. Intangible Assets

	March 31, 2007			December 31, 2006
	Cost	**Accumulated Amortization**	**Net Book value**	Net Book value
Engineering drawings	**$ 102,759**	**$ 2,355**	**$ 100,404**	$ 102,641
Marketing contracts	**7,147**	**397**	**6,750**	7,109
Customer lists	**4,327**	**199**	**4,128**	4,276
Fair value of office lease	**931**	**260**	**671**	726
Financing costs	**12,113**	**6,716**	**5,397**	7,610
Total	**$ 127,277**	**$ 9,927**	**$ 117,350**	$ 122,362

7. Other Non-Current Assets

	March 31, 2007	December 31, 2006
Deferred charges, net of amortization	**$ -**	$ 23,659
Discount on senior notes, net of amortization	**-**	1,408
Total	**$ -**	$ 25,067

8. Accounts Payable and Accrued Liabilities

	March 31, 2007	December 31, 2006
Trade accounts payable	**$ 88,824**	$ 111,837
Accrued interest	**20,677**	14,367
Trust Unit Incentive Plan and Unit Award Incentive Plan *[Note 13]*	**9,126**	6,442
Other accrued liabilities	**168,124**	161,936
Total	**$ 286,751**	$ 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 $684 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:

	March 31, 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 Viking	**-**	60,493
Incurred on acquisition of Birchill	**-**	1,219
Liabilities incurred	**1,068**	2,763
Revision of estimates	**-**	20,544
Liabilities settled	**(2,120)**	(9,186)
Accretion expense	**4,446**	15,954
Balance, end of period	**$ 207,503**	$ 202,480

Harvest has gross asset retirement obligations of approximately $14.7 million relating to the refining and marketing assets that is 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 February 1, 2007, Harvest fully repaid the remaining $289.7 million outstanding on the Senior Secured Bridge Facility.

At March 31, 2007, Harvest had $1,363.2 million drawn under its Three Year Extendible Revolving Credit Facility, of which $755.9 million is payable in U.S. dollars.

Subsequent to the end of the first quarter, we requested an extension of the maturity date from March 2009 to April 2010 for our $1.4 billion Three Year Extendible Revolving Credit Facility and sought to increase the facility from $1.4 billion to $1.6 billion. We have now upsized our facility to $1.6 billion and extended the maturity date to April 2010 on $1,535 million of the facility with one lender representing $65 million retaining the March 2009 maturity date.

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:

	March 31, 2007			December 31, 2006		
	Face Value	**Carrying Amount[1]**	**Fair Value**	Face Value	Carrying Amount[1]	Fair Value
9% Debentures Due 2009	$ 1,122	$ 1,098	$ 2,244	$ 1,226	$ 1,226	$ 2,280
8% Debentures Due 2009	2,060	2,001	3,399	2,239	2,229	3,731
6.5% Debentures Due 2010	37,929	34,943	39,370	37,929	35,988	37,925
10.5% Debentures Due 2008	26,621	26,777	27,555	26,621	26,824	28,085
6.40% Debentures Due 2012	174,693	167,592	164,561	174,743	167,401	159,485
7.25% Debentures Due 2013	379,500	353,013	382,157	379,500	367,843	375,705
7.25% Debentures Due 2014	230,000	207,760	247,480	-	-	-
	$ 851,925	**$ 793,184**	**$ 866,766**	**$ 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 March 31, 2007; therefore, unless otherwise noted, all references to Trust Units are deemed to be references to Ordinary Trust Units.

(b) Number of Units Issued

	Three months ended March 31, 2007	Three months ended March 31, 2006
Outstanding, beginning of period	**122,096,172**	52,982,567
Issued in exchange for assets of Viking	**-**	46,040,788
Issued for cash		
February 1, 2007	**6,146,750**	-
Convertible debenture conversions		
9% Debentures Due 2009	**7,508**	15,666
8% Debentures Due 2009	**11,137**	35,901
6.5% Debentures Due 2010	**-**	88,219
10.5% Debentures Due 2008	**-**	43,720
6.40% Debentures Due 2012	**1,086**	434
Exchangeable share retraction	**-**	184,809
Distribution reinvestment plan issuance	**1,802,681**	905,610
Exercise of unit appreciation rights and other	**6,959**	248,815
Outstanding, end of period	**130,072,293**	100,546,529

(c) Per Trust Unit Information

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

Net income adjustments		**March 31, 2007**		March 31, 2006
Net income (loss), basic	**$**	**69,850**	$	(33,937)
Non-controlling interest		**-**		(80)
Interest on convertible debentures		**77**		-
Net income (loss), diluted(1)	**$**	**69,927**	$	(34,017)

Weighted average Trust Units adjustments	**March 31, 2007**	March 31, 2006
Number of Units		
Weighted average Trust Units outstanding, basic	**126,987,698**	82,309,176
Effect of convertible debentures	**220,870**	-
Effect of exchangeable shares	**-**	100,847
Effect of Employee Unit Incentive Plans	**253,032**	-
Weighted average Trust Units outstanding, diluted(2)	**127,461,600**	82,410,023

(1) Net income, diluted excludes the impact of the conversions of certain of the convertible debentures of $15,017,000 for the three months ended March 31, 2007 (three months ended March 31, 2006 - $3,115,000), as the impact would be anti-dilutive.

(2) Weighted average Trust Units outstanding, diluted for the three months ended March 31, 2007 does not include the unit impact of 23,258,373 for certain of the convertible debentures (three months ended March 31, 2006 - 1,175,000), as the impact would be anti-dilutive. The impact of the Trust Unit incentive plans of nil (three months ended March 31, 2006 – 462,096) has also been excluded as the impact would be anti-dilutive.

13. Employee Unit Incentive Plans

Trust Unit Rights Incentive Plan
As at March 31, 2007, a total of 3,764,875 (3,788,125 – December 31, 2006) Unit Appreciation Rights were outstanding under the Trust Unit Rights Incentive Plan at an average exercise price of $28.04 ($29.14 – December 31, 2006).

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

	Three months ended March 31, 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	**138,000**	**26.36**	3,924,300	31.92
Exercised	**(22,650)**	**22.40**	(1,039,018)	18.58
Forfeited	**(138,600)**	**30.85**	(402,300)	37.25
Outstanding before exercise price reductions	**3,764,875**	**30.71**	3,788,125	30.81
Exercise price reductions	**-**	**(2.67)**	-	(1.67)
Outstanding, end of period	**3,764,875**	**$ 28.04**	3,788,125	$ 29.14
Exercisable before exercise price reductions	**520,850**	**$ 31.25**	266,125	$ 24.18
Exercise price reductions	**-**	**(5.11)**	-	(5.37)
Exercisable, end of period	**520,850**	**$ 26.14**	266,125	$ 18.81

The following table summarizes information about Unit Appreciation Rights outstanding at March 31, 2007.

		Outstanding			**Exercisable**	
Exercise Price before price reductions	**Exercise Price net of price reductions**	**At March 31, 2007**	**Weighted Average Exercise Price net of price reductions**[(1)]	**Remaining Contractual Life** [(1)]	**At March 31, 2007**	**Weighted Average Exercise Price net of price reductions**[(1)]
$12.19-$13.15	$3.66-$4.99	7,200	$ 4.58	1.7	7,200	$ 4.58
$13.35-$14.99	$5.38-$7.92	51,500	7.79	2.3	51,500	7.79
$18.90-$25.10	$11.91-$24.26	152,375	18.66	3.3	127,675	17.72
$26.17-$27.37	$24.71-$26.99	1,744,400	24.82	4.7	-	-
$29.21-$37.56	$23.79-$34.58	1,809,400	32.60	4.0	334,475	32.65
$12.19-$37.56	$3.66-$34.58	3,764,875	$ 28.04	4.3	520,850	$ 26.14

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

Unit Award Incentive Plan
At March 31, 2007, 309,337 Units were outstanding under the Unit Award Incentive Plan.

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

	Three months ended March 31, 2007	Year ended December 31, 2006
Outstanding, beginning of period	**306,699**	35,365
Granted	**15,462**	320,905
Adjusted for distributions	**12,109**	27,879
Exercised	**(16,258)**	(41,530)
Forfeitures	**(8,675)**	(35,920)
Outstanding, end of period	**309,337**	306,699

Harvest has recognized $2.9 million as compensation expense for the three months ended March 31, 2007 ($8.4 million – three months ended March 31, 2006), including non cash compensation expense of $2.4 million for the three months ended March 31, 2007 ($3.2 million – three months ended March 31, 2006), related to the Trust Unit Rights Incentive Plan and the Unit Award Incentive Plan and this is reflected in general and administrative expense in the consolidated statements of income.

14. 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 for the three months ended March 31, 2007.

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;

	March 31, 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:

	March 31, 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.

	Three Months ended March 31, 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	**761**	**92**	648	88
Interest	**593**	**79**	546	74
Actuarial losses	**408**	**12**	3,422	601
Plan amendment	**-**	**-**	-	-
Benefits paid	**(154)**	**(50)**	(269)	(51)
Impact of foreign exchange on translation	**-**	**-**	-	-
Employee benefit obligation, end of period	**44,709**	**6,160**	43,101	6,027
Fair value of plan assets, beginning of period	**36,576**	**-**	31,878	-
Expected return on plan assets	**666**	**-**	3,181	-
Employer contributions	**825**	**50**	1,306	51
Employee contributions	**408**	**-**	480	-
Benefits paid	**(154)**	**(50)**	(269)	(51)
Impact of foreign exchange on translation	**-**	**-**	-	-
Fair value of plan assets, end of period	**38,321**	**-**	36,576	-
Funded status	**(6,388)**	**(6,160)**	(6,525)	(6,027)
Unamortized balances:				
Net actuarial losses	**325**	**-**	325	-
Past services	**-**	**-**	-	-
Carrying amount	**$ (6,063)**	**$ (6,160)**	$ (6,200)	$ (6,027)

	March 31, 2007	December 31, 2006
Summary:		
Pension plans	$ **6,063**	$ 6,200
Other benefit plans	**6,160**	6,027
Carrying amount	$ **12,223**	$ 12,227

Estimated pension and other benefit payments to plan participants, which reflect expected future service, expected to be paid from 2007 to 2016 are summarized in the commitment table [see Note 18].

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

	Three Months ended March 31, 2007		Year ended March 31, 2006	
	Pension Plans	Other Benefit Plans	Pension Plans	Other Benefit Plans
Current service cost	$ **761**	$ **92**	$ -	$ -
Interest costs	**593**	**79**	-	-
Expected return on assets	**(666)**	**-**	-	-
Amortization of net actuarial losses	-	-	-	-
Amortization of past services	-	-	-	-
Net benefit plan expense	$ **688**	$ **171**	$ -	$ -

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)

15. Financial Instruments and risk management contracts

Financial instruments of Harvest consist of 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 is disclosed below by financial instrument category, as well as any related gains/(losses) and interest income or expense:

Financial Instrument (in $000's)	Carrying Value	Fair Value	Gains/ (Losses)	Interest Income/ (Expense)	Other Income/ (Expense)
Loans and Receivables					
Accounts receivable	302,506	302,506	-	-	-
Lease payments receivable	4,055(1)	4,055	-	57(2)	-
Liabilities Held for Trading					
Net fair value of risk management contracts	16,012(3)	16,012	(14,418) (4)	-	-
Other Liabilities					
Accounts payable	286,751	286,751	-	-	-
Cash distributions payable	49,427	49,427	-	-	-
Bank Loan	1,363,222	1,363,222	-	(20,423)(5)	(2,481)(5)
$7^{7/8}$% Senior Notes	279,612(7)	276,743	-	(6,145)(6)	-
Convertible Debentures	793,184	866,766	-	(15,094)(6)	-

(1) Included in accounts receivable on the balance sheet.
(2) Included in interest and other financing charges on short term/long term debt in the statement of income and comprehensive income.
(3) Included in the balance sheet as follows: Fair value of risk management contracts (current assets) $7,981, fair value of risk management contracts $9,614, fair value deficiency of risk management contracts (current liabilities) $30,050 and fair value deficiency of risk management contracts $3,557.
(4) Included in risk management contracts - realized and unrealized gains/(losses) in the statement of income and comprehensive income.
(5) 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.
(6) 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.
(7) The face value of the $7^{7/8}$%Senior Notes at March 31, 2007 $288.7 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 March 31, 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 distributions payable, their carrying values approximate their fair values.

The Amended and Restated Credit Agreement entered into on October 19, 2006 is secured by a $2.5 billion first floating charge over all of the assets of Harvest's operating subsidiaries plus a first mortgage security interest on the refinery assets of the North Atlantic.

(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

Petroleum and Natural Gas accounts receivable

Accounts receivable in our petroleum and natural gas 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 purchasers 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 set off provision that enables us to use the proceeds form the sale of production that would otherwise be taken in kind by the partner to set 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 March 31, 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. as all feedstock purchases and substantially all products sales are made with Vitol Refining S.A. Harvest mitigates this risk by requiring that Vitol Refining S.A. 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 refining and marketing 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 managed 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 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, floating rate debt denominated in U.S. dollars and bearing interest relative to the U.S. interest benchmark rate and fixed rate debt denominated in U.S. dollars.

In addition, Harvest manages its interest rate 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. In addition, Harvest's $7^{7/8}$% Senior Notes are denominated in U.S. dollars (U.S.$250 million) and a portion of our credit facility is drawn in U.S. dollars. 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 and natural gas 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

The risk management contracts are presented at fair value on the balance sheet. The following is a summary of Harvest's risk management contracts outstanding, along with their fair value at March 31, 2007:

Quantity	Type of Contract	Term	Reference	Fair value
1,000 bbl/d	Differential swap – Wainwright	April 2007	27.70%	$ 34
5,000 bbl/d	Participating swap	April – December 2007	U.S.$65.00[(a)]	3,070
35 MWH	Electricity price swap contracts	April – December 2007	Cdn $56.69	4,877
Total current portion of fair value				**$ 7,981**
5,000 bbl/d	Participating swap	January – December 2008	U.S.$65.00[(b)]	$ 1,601
35 MWH	Electricity price swap contracts	January – December 2008	Cdn $56.69	8,013
Total long-term portion of fair value				**$ 9,614**
5,000 bbl/d	Participating swap	April – June 2007	U.S.$49.03[(c)]	$ (2,356)
10,000 bbl/d	Participating swap	April – December 2007	U.S.$55.00[(b)]	(13,134)
5,000 bbl/d	Participating swap	April – December 2007	U.S.$60.00[(d)]	(1,427)
5,000 bbl/d	Indexed put contract – bought put	April – December 2007	U.S.$50.00[(e)]	400
2,500 bbl/d	Indexed put contract – sold call	April – December 2007	U.S.$50.00[(e)]	(14,778)
2,500 bbl/d	Indexed put contract – bought call	April – December 2007	U.S.$60.00[(e)]	7,923
2,500 bbl/d	Indexed put contract – sold call	April – December 2007	U.S.$70.00[(e)]	(3,105)
2,500 bbl/d	Indexed put contract – bought call	April – December 2007	U.S.$83.00[(e)]	738
200 GJ/d	Fixed price – natural gas contract	April – December 2007	Cdn.$4.13[(g)]	(196)
76 GJ/d	Fixed price – natural gas contract	April – December 2007	Cdn.$2.16-2.22[(g)]	(119)
10,000 GJ/d	Natural gas 3-way costless collar	April 2007 – March 2008	Cdn$5.00-$10.30(7.00)[(h)]	(563)
20,000 GJ/d	Natural gas 3-way costless collar	April 2007 – March 2008	Cdn$5.00-$10.25(7.00) [(i)]	(1,147)
$416,700/mnth	U.S./Cdn dollar exchange rate swap	April – December 2007	1.14 Cdn/U.S.	(38)
$4,167,000/mnth	U.S./Cdn dollar exchange rate swap	April - December 2007	1.1189 Cdn/U.S.	(1,315)
$4,167,000/mnth	U.S./Cdn dollar exchange rate swap	April – December 2007	1.1249 Cdn/U.S.	(933)
Total current portion of fair value deficiency				**$ (30,050)**
5,000 bbl/d	Participating swap	January – December 2008	U.S.$55.00[(f)]	$ (1,492)
200 GJ/d	Fixed price – natural gas contract	January – December 2008	Cdn. $4.67[(g)]	(261)
76 GJ/d	Fixed price – natural gas contract	January – October 2008	Cdn. $2.22[(g)]	(143)
$8,333,000/mnth	Foreign currency swap	January – June 2008	1.1099 Cdn/U.S.	(1,661)
Total long-term portion of fair value deficiency				**$ (3,557)**

(a) This price is a floor. Harvest realizes this price plus 79% of the difference between spot price and this price.
(b) This price is a floor. Harvest realizes this price plus 67% of the difference between spot price and this price.
(c) This price is a floor. Harvest realizes this price plus 75% of the difference between spot price and this price.
(d) This price is a floor. Harvest realizes this price plus 77% of the difference between spot price and this price.
(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.
(f) This price is a floor. Harvest realizes this price plus 80% of the difference between spot price and this price
(g) This contract contains an annual escalation factor such that the fixed price is adjusted each year.
(h) If the market price is below $5.00, price received is market price plus $2.00; if the market price is between $5.00 and $7.00, the price received is $7.00; if the market price is between $7.00 and $10.30, the price received is market price; if the market price is over $10.30, price received is $10.30.
(i) If the market price is below $5.00, price received is market price plus $2.00; if the market price is between $5.00 and $7.00, the price received is $7.00; if the market price is between $7.00 and $10.25, the price received is market price; if the market price is over $10.25, price received is $10.30.

At March 31, 2007, the net fair value deficiency reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $16.0 million ($1.9 million – December 31, 2006).

For the three months ended March 31, 2007, the total unrealized loss recognized in the consolidated statement of income and comprehensive income, was $14.1 million ($41.0 million – three months ended March 31, 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.

16. Segment Information

Harvest operates in Canada and has two reportable operating segments for the period ending March 31, 2007, Petroleum and Natural Gas and Refining and Marketing. For the period ending March 31, 2006, Harvest's only operating segment was the Petroleum and Natural Gas operations.

Petroleum and Natural Gas – Harvest's petroleum and natural gas operations consist of development, production and subsequent sale of petroleum, natural gas and natural gas liquids.

Refining and Marketing – Harvest's refining and marketing operations includes 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.

	March 31, 2007		
	Refining and Marketing[(1)]	Petroleum and Natural Gas[(1)]	**Total**
Revenue	$ 784,045[(2)]	$ 291,116	**$ 1,075,161[(3)]**
Royalties	-	(49,649)	**(49,649)**
Realized net losses	-	(297)	**(297)**
Unrealized net losses	-	(14,121)	**(14,121)**
Less: expenses			
Purchased products for resale and processing	632,296	-	**632,296**
Operating	49,661	72,296	**121,957**
Transportation and marketing	7,343	2,812	**10,155**
General and administrative	-	10,104	**10,104**
Depletion, depreciation, amortization and accretion	19,389	114,403	**133,792**
	$ 75,356	$ 27,434	**$ 102,790**
Interest and other financing charges on short term debt, net			**(3,627)**
Interest and other financing charges on long term debt			**(40,449)**
Foreign exchange gain/(loss)			**11,260**
Large corporate tax and other tax			**(124)**
Net income			**$ 69,850**
Total Assets[(1)]	$ 1,729,069	$ 4,071,277	**$ 5,800,346**
Capital Expenditures			
Development and other activity	$ 4,883	$ 148,487	**$ 153,370**
Business acquisitions	-	30,264	**30,264**
Property acquisitions	-	3,111	**3,111**
Property dispositions	-	(2,422)	**(2,422)**
Total expenditures	$ 4,883	$ 179,440	**$ 184,323**
Property, plant and equipment			
Cost	$ 1,306,618	$ 3,981,413	**$ 5,288,031**
Less: Accumulated depletion, depreciation, amortization and accretion	(31,942)	(816,497)	**(848,439)**
Net book value	$ 1,274,676	$ 3,164,916	**$ 4,439,592**
Goodwill, beginning of period	$ 209,930	$ 656,248	**$ 866,178**
Reduction to goodwill	(1,946)	-	**(1,946)**
Goodwill, end of period	$ 207,984	$ 656,248	**$ 864,232**

(1) Accounting policies for segments are the same as those described in the Significant Accounting Policies
(2) Of the total Refining and Marketing revenue for the three month period ended March 31, 2007, $733.6 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 March 31, 2007 $341.6 million is attributable to sales in Canada, while $733.6 million is attributable to sales in the United States.
(4) There is no intersegment activity.

17. Change in Non-Cash Working Capital

		Three months ended		
		March 31, 2007		March 31, 2006
Changes in non-cash working capital items:				
Accounts receivable	**$**	**(47,415)**	$	8,926
Prepaid expenses and deposits		**(675)**		(1,833)
Current portion of risk management contracts assets		**9,933**		11,918
Inventory		**(10,449)**		-
Current portion of future income tax asset		**-**		22,975
Accounts payable and accrued liabilities		**(10,821)**		9,992
Cash distribution payable		**3,030**		(2,209)
Current portion of risk management contracts liability		**3,286**		16,245
	$	**(53,111)**	$	66,014
Changes relating to operating activities	**$**	**(100,773)**	$	(6,617)
Changes relating to financing activities		**6,202**		(13,301)
Changes relating to investing activities		**24,003**		15,696
Add: Non-cash changes		**17,457**		70,236
	$	**(53,111)**	$	66,014

18. Commitments, Contingencies and Guarantees

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

The following are the significant commitments at March 31, 2007:

(a) North Atlantic has a Supply and Offtake Agreement with Vitol Refining S.A. This agreement provides that the ownership of substantially all crude oil feedstock and refined product inventory at the refinery be retained by Vitol Refining S.A. and that for a minimum period of up to two years Vitol Refining S.A. will be granted the right and obligation to provide crude oil feedstock for delivery to the refinery, as well as the right and obligation to purchase substantially all refined products produced by the refinery. As such, at March 31, 2007, North Atlantic had commitments totaling approximately $798.5 million in respect of future crude oil feedstock purchases and related transportation from Vitol Refining S.A.

The following is a summary of Harvest's contractual obligations and commitments as at March 31, 2007:

	Payments Due by Period						
	2007	**2008**	**2009**	**2010**	**2011**	**Thereafter**	**Total**
Debt repayments (1)	-	-	65,000	1,298,222	288,650	-	1,651,872
Capital commitments(2)	11,285	2,880	-	-	-	-	14,165
Operating leases(3)	4,715	5,760	4,969	2,157	258	258	18,117
Pension contributions(4)	585	1,510	1,835	2,219	2,586	19,147	27,882
Transportation agreements(5)	1,498	1,452	893	226	30	-	4,099
Feedstock commitments(6)	791,720	6,777	-	-	-	-	798,497
Contractual obligations	809,803	18,379	72,697	1,302,824	291,524	19,405	2,514,632

(1) Assumes that the outstanding convertible debentures either convert at the holders' option for Units or are redeemed for Units at Harvest's option.
(2) Relating to drilling contracts, AFE commitments and equipment rental contracts.
(3) Relating to building and automobile leases.
(4) Relating to expected contributions for employee benefit plans [see Note 14].
(5) Relating to oil and natural gas pipeline transportation agreements.
(6) Relating to crude oil feedstock purchases and related transportation costs [see Note 18 (a) above].

19. Subsequent Events

Subsequent to March 31, 2007, Harvest declared a distribution of $0.38 per unit for Unitholders of record on April 23, 2007, May 24, 2007 and June 22, 2007.

Between April 1, 2007 and May 1, 2007, an additional U.S. $274.6 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 18].

20. Comparatives

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