## Financial & Operating Highlights

The table below provides a summary of Harvest's financial and operating results for the three and six month periods ended June 30, 2006 and 2005, and the first quarter of 2006.

| | Three Months Ended | | | Six Months Ended | |
|---|---|---|---|---|---|
| *($000s except where noted)* | **June 30, 2006** | March 31, 2006 | June 30, 2005 | **June 30, 2006** | June 30, 2005 |
| Revenue, net (1) | **233,128** | 131,432 | 102,007 | **364,560** | 118,545 |
| Cash Flows (2) | **147,010** | 100,971 | 57,217 | **247,981** | 109,904 |
| Per Trust Unit, basic (2) | **$ 1.45** | $ 1.23 | $ 1.32 | **$ 2.70** | $ 2.57 |
| Per Trust Unit, diluted (2) | **$ 1.43** | $ 1.22 | $ 1.29 | **$ 2.66** | $ 2.45 |
| Net income | **60,682** | (33,937) | 19,516 | **26,745** | (23,554) |
| Per Trust Unit, basic (2) | **$ 0.60** | $ (0.41) | $ 0.45 | **$ 0.29** | $ (0.55) |
| Per Trust Unit, diluted (2) | **$ 0.60** | $ (0.41) | $ 0.44 | **$ 0.29** | $ (0.56) |
| Distributions declared | **115,889** | 94,812 | 26,140 | **210,701** | 62,266 |
| Distributions declared, per Trust Unit | **1.14** | 1.11 | 0.60 | **2.25** | 1.20 |
| Payout ratio (2)(3) | **79%** | 94% | 46% | **85%** | 47% |
| Capital asset additions (excluding acquisitions) | **54,230** | 103,239 | 26,154 | **157,469** | 49,377 |
| Bank Debt | **227,554** | 201,652 | 138,090 | **227,554** | 138,090 |
| **Production** | | | | | |
| Light to medium oil (bbl/d) | **28,951** | 23,900 | 15,336 | **26,497** | 15,474 |
| Heavy oil (bbl/d) | **13,037** | 15,182 | 13,519 | **14,045** | 13,993 |
| Natural gas liquids (bbl/d) | **2,016** | 1,709 | 798 | **1,865** | 789 |
| Natural gas (mcf/d) | **96,848** | 73,337 | 28,857 | **85,158** | 27,990 |
| Total daily sales volumes (boe/day) | **60,145** | 53,014 | 34,463 | **56,600** | 34,921 |

(1) Revenues are net of royalties and risk management contracts.
(2) These are non-GAAP measures; please refer to "Non-GAAP" measures in this MD&A
(3) Ratio of distributions declared to Cash Flows, excluding special distribution of $10.7 million settled with the issuance of Trust Units in 2005

## Message to Unitholders

Harvest's second quarter 2006 marks the first full reporting period incorporating the assets of Viking Energy Royalty Trust acquired in the first quarter. I am proud of the success of our team in completing the integration with Viking, and our focus continues to be on activities that support Harvest's long term operational, financial and distribution sustainability.

### Q2 Review

Our production volumes in the second quarter averaged 60,145 barrels of oil equivalent (boe) per day. Compared to our first quarter production volumes of 53,014 boe/d, second quarter production is 13% higher and a better reflection of our current productive capacity. Second quarter cash flow per unit was $1.45, 18% higher than the $1.23 reported in the previous quarter. At 79%, our second quarter payout ratio was within our expected range.

Our higher cash flow per unit was supported by crude prices that were 11% higher in the second quarter compared to the first quarter, as well as lower differentials for heavy oil. Relative to the first quarter, second quarter heavy oil prices were 52% higher, due in part to narrower differentials as the summer paving season commenced, as well as higher overall crude prices. Unfortunately, natural gas prices continued to weaken, as Alberta daily index prices were 20% lower in the second quarter compared to the first quarter, and continue to be significantly lower than levels realized late in 2005. After cash distributions and capital spending, we generated net Cash Flows of $26.9 million in the quarter, which was utilized to reduce bank debt and which reflected an increase of 76% compared to $6.4 million of net Cash Flows generated in the second quarter of 2005.

Second quarter production reflects volume additions from our Hay River drilling program which came on-stream in mid-quarter, as well as benefits realized from improved pumping technology implemented in the area. The positive gains from drilling in Hay River and other areas were partly offset by a scheduled turnaround at a third party processing facility that exceeded our budgeted downtime by more than two weeks. Although the facility came back on-stream late in the second quarter, our production volumes at the affected property were restored slightly below levels experienced prior to the turnaround.

**Operational Sustainability**
An important element of Harvest's sustainability is the short, medium and longer term opportunities we see in our asset base. These opportunities are supported by our capital program, which is heavily weighted to drilling and production optimization projects in the short term. We are proud of the successes we have realized to date, including production growth from drilling and the identification of new productive trends in Southeast Saskatchewan; improved pumping performance with electric submersible pumps at Hay River; tighter downspace drilling in Markerville; and exciting drilling results and production growth in Ferrier.

During the second quarter, we drilled 23 net wells with a success rate of 100%, and year to date have drilled 93 net wells compared to 41 for the first six months in 2005. This substantial increase in drilling activity has moved Harvest into the top ten most active drillers in the Western Canadian Sedimentary Basin. The benefits of our size, extensive inventory of development projects, larger capital program and technical expertise are demonstrated in our ability to maintain an eight rig drilling program throughout the entire year. As such, we are not subject to rig availability and can maximize the efficiency of our program by moving rigs quickly to the opportunities offering the highest value within our asset base.

In the medium and longer term, Harvest is focused on innovative techniques to improve the recovery of the large hydrocarbon deposits situated on our working interest lands. With over 2 billion boe of original resource in place, and a total reserve recovery to date of only 25%, we are actively pursuing activities and technologies that can improve recovery from these pools. An incremental 10% improvement in recovery equates to an additional 200 million boe of produced reserves. Medium term initiatives include improved waterflooding at Hay River; water handling upgrades at Suffield; and well reactivations in Eastern Alberta. Over the longer term, we will continue to test and develop enhanced oil recovery projects including polymer, solvent and carbon dioxide flooding, pursue the Coal Bed Methane potential on our lands, and expand our existing inventory of oil sands opportunities.

During the quarter we acquired 27 sections (equivalent to 17,280 acres) of oil sands leases in our Northern Alberta area, adjacent to our Red Earth property. This acquisition is important to Harvest because it expands our rights in the area to include the oil sands horizon in addition to the conventional productive hydrocarbon zones, and brings our total oil sands leases to 26,200 gross and net acres. Management has extensive experience maximizing heavy oil and oil sands production, and these assets further contribute to our long-term sustainability goals.

We continue to seek opportunities to consolidate within our core areas, create new core areas, as well as identify unique opportunities that may arise domestically or internationally. Consistent with our success in the past, Harvest will continue to be opportunistic in our approach to acquisitions. Our goal is to undertake acquisitions that are accretive to reserves, production and cash flow per unit, rather than conform to a specific production mix, reserve life or geographic area. With the significant undrawn capacity under our credit facility, we are financially well positioned to continue taking advantage of future opportunities.

**Financial Sustainability**
Hedging continues to be an important part of Harvest's risk management strategy. We attempt to establish price floors that provide sustainability, while still allowing for upside participation. In 2007, our hedging contracts have a floor price that is $10.81 higher than in 2006 with greater participation above the floor, which is expected to increase our cash flow in 2007 and reduce the payout ratio under current commodity price levels. For the balance of 2006, we have over 50% of our oil volumes hedged using contracts that provide for participation of approximately 55% above the average U.S.$45.47 floor price. In 2007, we have approximately 60% of our oil volumes hedged with greater than 73% participation above the U.S.$56.28 average floor price.

With the increase in our natural gas weighting over the past six months, we have also layered in some downside natural gas price protection with costless collars. For the balance of 2006, approximately 25% of our natural gas production is hedged with average floor and ceiling prices of $5.92 and $13.28, respectively, and approximately 11% of our estimated 2007 natural gas production is protected with average floor and ceiling prices of $6.00 and $13.03, respectively.

Our non-resident ownership has increased to approximately 44% at the end of the second quarter from approximately 33% at the end of the first quarter. We believe this increase reflects the ongoing interest in Harvest's financial and operational sustainability, as well as our ongoing marketing efforts to new audiences. With our third quarter 2006 distributions announced at the Cdn$0.38 per unit level, Harvest offers unitholders sustainability as well as the potential for yield compression through price appreciation.

**Recent Developments**
On July 26, 2006, Harvest announced the $440 million acquisition of a private Canadian oil and natural gas company, adding approximately 6,300 boe/d of primarily natural gas production and 22.6 million boe of proved plus probable (P+P) reserves to our portfolio. This acquisition elevates our P+P reserve life index to 9.5 years, provides significant multi-zone drilling and development opportunities, lightens up our crude oil mix and modifies our production weighting to approximately 70% crude oil / liquids, and 30% natural gas. The acquired properties fit well with Harvest's existing assets in our Western Alberta core area, providing overlapping and adjacent lands in Sylvan Lake / Markerville, Willesden Green, Wilson Creek and Ferrier. This acquisition supports Harvest's future development activities by increasing our total undeveloped land to approximately 800,000 net acres, and expanding our seismic inventory. It is also accretive to Cash Flow per unit, reserves per unit and production per unit, and is expected to raise our 2006 exit production to approximately 66,000 boe/d. Our capital expenditure program for 2006 has also been increased by $50 million to $300 million; $25 million allocated to the acquired properties, and $25 million to our existing assets for further crude oil development which will add incremental production and cost benefits in 2007.

Concurrent with the acquisition, we announced a $200 million bought deal equity financing in Canada, the proceeds of which were used to partially fund the acquisition, with the underwriters having an option to increase the amount to $230 million. The balance of the acquisition cost was financed through our existing credit facility, which will continue to have more than $400 million of undrawn capacity following closing of the acquisition and financing. Our balance sheet strength positions Harvest well to continue seeking out and capitalizing on acquisition opportunities as they arise.

Just after the end of the second quarter, a non-operated facility in the Sylvan Lake / Markerville area was shut down following a fire that damaged one of the compressors. Although Harvest was able to redirect a portion of our Markerville volumes shortly after the incident, approximately 3,500 boe/d of natural gas and liquids remained off-line until early August. Although the operator has restored the majority of its processing capabilities in Markerville, approximately 500 boe/d remains shut-in and is expected to come back on stream through the third quarter.

**Conference Call & Webcast**
To provide further discussion of our second quarter 2006 financial and operating results, Harvest will be hosting a conference call and Webcast at 9:00 a.m. Mountain time (11:00 a.m. Eastern time) on August 10th, 2006. Callers may dial 1-877-888-3490 (international callers or Toronto local dial 416-695-5259) a few minutes prior to start and request the Harvest conference call. The call will also be available for replay by dialing 1-888-509-0081 (international callers or Toronto local dial 416-695-5275) and entering passcode 626360.

Webcast listeners are invited to go to the Investor Relations – Presentations & Events page of the Harvest Energy website at www.harvestenergy.ca for the live Webcast and/or a replay of the Webcast.

Harvest is one of Canada's largest energy royalty trusts. We are focused on identifying opportunities within the oil and natural gas sector to create and deliver value to unitholders through monthly distributions and unit price appreciation. With an active acquisition program and the technical approach taken to maximizing our assets, we strive to grow Cash Flow per unit. Harvest offers unitholders a sustainable trust with a reserve life index of 9.5 years, and current production weighted approximately 70% to crude oil and liquids and 30% to natural gas. Harvest trust units are traded on the Toronto Stock Exchange ("TSX") under the symbol "HTE.UN" and on the New York Stock Exchange ("NYSE") under the symbol "HTE".

**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, 2005 and 2004 as well as our unaudited consolidated financial statements and notes for the three and six month periods ended June 30, 2006. 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. The information and opinions concerning our future outlook are based on information available at August 9, 2006.

When reviewing our 2006 results and comparing them to 2005, readers are cautioned that the 2006 results include two full quarters of operations from our Hay River acquisition in the third quarter of 2005 and only five months of operations from our acquisition of Viking in February 2006. The combination of these events significantly impacts the comparability of our operations and financial results for 2006 to the results of the same period of 2005. To increase comparability, in certain instances, we have provided financial information for the first quarter of 2006, which reflects the results of operations of Harvest plus two months of results of Viking.

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.

We use certain financial reporting measures that are commonly used as benchmarks within the oil and natural gas industry in the following MD&A such as Cash Flow, Payout Ratio, Cash General and Administrative Expenses and Operating Netbacks (calculation tables within the MD&A) each as defined in this MD&A. These measures are not defined under Canadian generally accepted accounting principles ("GAAP") and should not be considered in isolation or as an alternative to conventional GAAP measures. Certain of these measures are not necessarily comparable to a similarly titled measure of another company or trust. When these measures are used, they are defined as "non-GAAP" and should be given careful consideration by the reader. Please refer to the discussion under the heading "Non-GAAP Measures" at the end of this MD&A for a detailed discussion of these reporting measures.

## Financial and Operating Highlights – Second Quarter 2006

- Cash Flows for the three months ended June 30, 2006 totaled $147.0 million ($1.45 per basic Trust Unit) a 46% increase over $101.0 million earned in the first quarter of 2006. Cash distributions of $1.14 per Trust Unit in the quarter resulted in a payout ratio of 79% compared to $1.11 per Trust Unit and a payout ratio of 94% in the first quarter of 2006.
- Record production of 60,145 boe per day (boe/d), an increase in average daily production of 13% over the first quarter of 2006 production of 53,014 boe/d.
- Second quarter capital reinvestment of $54.2 million (year to date capital reinvestment of $157.5 million) directed toward enhancing the recoveries from our resource base weighted 49% to drilling / and tie-in activities and 30% to workovers and facilities. In the second quarter we drilled 23 net wells, with a success rate of 100%.
- Subsequent to the end of the quarter we announced an agreement to acquire a private Canadian oil and natural gas company with current production of approximately 6,300 boe/d, weighted to natural gas, and proved plus probable (P+P) reserves of approximately 22.6 mmboe and concurrently announced a $200 million equity financing with the underwriters having an option to increase the financing to $230 million.
- Strong balance sheet with an estimated $672.5 million of undrawn credit capacity at June 30, 2006.

The table below provides a summary of our financial and operating results for the three and six month periods ended June 30, 2006 and June 30, 2005. Detailed commentary on individual items within this table is provided elsewhere in this MD&A.

| | Three months ended | | | | Six months ended | | |
|---|---|---|---|---|---|---|---|
| **FINANCIAL** *($000s except where noted)* | **June 30, 2006** | March 31, 2006 | June 30, 2005 | 2006 to 2005 Quarter Change | **June 30, 2006** | June 30, 2005 | Year over Year Change |
| Revenue, net[1] | **233,128** | 131,432 | 102,007 | 129% | **364,560** | 118,545 | 208% |
| Cash Flow[2] | **147,010** | 100,971 | 57,217 | 157% | **247,981** | 109,904 | 126% |
| Per Trust Unit, basic[2] | **$ 1.45** | $ 1.23 | $ 1.32 | 10% | **$ 2.70** | $ 2.57 | 5% |
| Per Trust Unit, diluted[2] | **$ 1.43** | $ 1.22 | $ 1.29 | 11% | **$ 2.66** | $ 2.45 | 6% |
| Net income (loss) | **60,682** | (33,937) | 19,516 | 211% | **26,745** | (23,554) | 214% |
| Per Trust Unit, basic | **$ 0.60** | $ (0.41) | $ 0.45 | 33% | **$ 0.29** | $ (0.55) | 153% |
| Per Trust Unit, diluted | **$ 0.60** | $ (0.41) | $ 0.44 | 36% | **$ 0.29** | $ (0.56) | 152% |
| Distributions declared | **115,889** | 94,812 | 26,140 | 343% | **210,701** | 62,266 | 238% |
| Distributions declared, per Trust Unit | **$ 1.14** | $ 1.11 | $ 0.60 | 90% | **$2.25** | $ 1.20 | 55% |
| Payout ratio [2][3] | **79%** | 94% | 46% | 33% | **85%** | 47% | 28% |
| Cash capital asset additions (excluding acquisitions) | **54,230** | 103,239 | 26,154 | 107% | **157,469** | 49,377 | 227% |
| Bank debt | **227,554** | 201,652 | 138,090 | 65% | **227,554** | 138,090 | 65% |
| **Production** | | | | | | | |
| Light to medium oil (bbl/d) | **28,951** | 23,900 | 15,336 | 89% | **26,497** | 15,474 | 71% |
| Heavy oil (bbl/d) | **13,037** | 15,182 | 13,519 | (4%) | **14,045** | 13,993 | -% |
| Natural gas liquids (bbl/d) | **2,016** | 1,709 | 798 | 153% | **1,865** | 789 | 136% |
| Natural gas (mcf/d) | **96,848** | 73,337 | 28,857 | 236% | **85,158** | 27,990 | 204% |
| Total daily sales volumes (boe/day) | **60,145** | 53,014 | 34,463 | 75% | **56,600** | 34,921 | 62% |

(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) Ratio of distributions declared to Cash Flows, excluding special distribution of $10.7 million settled with the issuance of Trust Units in 2005.

## Review of Operations and Strategy

The second quarter of 2006 was our first full quarter reflecting the full impact of the acquisition of Viking Energy Royalty Trust, acquired on February 3, 2006. A strong crude oil and heavy oil differential pricing environment benefited our Cash Flows during the quarter, despite relative continued weakness in natural gas prices. We generated Cash Flows of $147.0 million ($1.45 per basic trust unit) in the second quarter of 2006, compared to $57.2 million ($1.32 per basic trust unit) in the same period in 2005. This $89.8 million increase is substantially attributed to the incremental impact of Viking and Hay River. Our higher operating expenses reflect the trend of rising cost pressures in the oil and natural gas sector.

Distributions declared during the quarter totaled $1.14 per trust unit, for a payout ratio of 79%, within our expected payout range of 55% to 80%. This is a 3% increase over the $1.11 per trust unit declared in the first quarter of 2006 and a decrease from the 94% payout ratio for that quarter. It also represents a 90% increase over the $0.60 per trust unit declared in the second quarter of 2005. These distribution increases reflect the success we have realized in operating our business to maximize production, enhance reserve recovery, and make accretive acquisitions in a rising commodity price environment. We will continue to manage our payout ratio and strive for a long-term target between 55%-80%, and would expect our payout ratio to fall between 70-80% for the remaining quarters of 2006, assuming commodity prices remain at current levels.

Production volumes were 60,145 boe/d, which is more reflective of our current productive capacity. The first quarter was a very active period for our drilling programs and incremental production volumes of 1,400 boe/day from our Hay River winter drilling program came on-stream during the second quarter. This additional production offset some production lost elsewhere due to an extended turnaround in June which occurred at a third party operated facility. The operator had expected this turnaround to be completed within several days, but the process actually took several weeks. The turnaround was complete before the end of the quarter but production volumes were restored at slightly lower levels than those experienced prior to the turnaround.

During the second quarter, we continued to actively deploy our capital program, although the onset of spring break-up curtails some projects until access is restored. We invested $54.2 million in our properties during the second quarter of 2006, an increase of 107% over the same period in 2005. This reflects our larger size and greater opportunity portfolio, as well as our ability to run a consistent capital program throughout the year. Of the total capital spent, 49% was allocated to drilling and equipping activities. We drilled 4 net wells in SE Saskatchewan, 3 net wells in Suffield, 3 net wells in Red Earth and 3 net wells in Markerville, with a 100% success rate. Our year to date capital investment was $157.5 million excluding acquisitions.

Our investment during the second quarter included the acquisition of oil sands rights in Northern Alberta, which is expected to further our long term sustainability. We acquired 17,280 gross and net acres of oil sands rights in the Red Earth area of Alberta, which complements our existing conventional oil sands production of approximately 600 boe/d from our Lindbergh property.

Subsequent to the second quarter, we announced an agreement to acquire a private Canadian oil and natural gas company with current production of approximately 6,300 boe/d weighted to natural gas, and proved plus probable (P+P) reserves of approximately 22.6 mmboe. This acquisition is accretive to cash flow per unit, reserves per unit and production per unit, and increases Harvest's Reserve Life Index (RLI) to 9.5 years. In addition, the operating costs are under $4.00 / boe. The acquisition will be financed partially with bank debt and partially with the issuance of 6,110,000 trust at a price of $32.75 per unit. Following completion of the acquisition and concurrent financing, our credit facility will continue to have over $400 million in undrawn capacity, positioning Harvest very well for future opportunities. With the addition of the 6,300 boe/d from the acquisition added for the last 5 months of the year, our forecast exit production volume for 2006 is expected to be approximately 66,000 boe/d.

Our balance sheet continues to strengthen with our Senior Debt to Capitalization at 8% and Total Debt to Capitalization at 17% and an undrawn credit capacity of $672.4 million at June 30, 2006.

## REVIEW OF QUARTERLY OPERATIONS

| **Commodity Price Environment** | **Three months ended June 30** | | | **Six months ended June 30** | | |
|---|---|---|---|---|---|---|
| Benchmarks | **2006** | 2005 | Change | **2006** | 2005 | Change |
| West Texas Intermediate crude oil (US$ per barrel) | **70.70** | 53.17 | 33% | **67.09** | 51.51 | 30% |
| Edmonton light crude oil ($ per barrel) | **78.63** | 65.79 | 20% | **73.80** | 63.67 | 16% |
| Bow River blend crude oil ($ per barrel) | **60.59** | 39.72 | 53% | **50.28** | 39.07 | 29% |
| AECO natural gas daily ($ per mcf) | **6.01** | 7.36 | (18%) | **6.67** | 7.13 | (6%) |
| AECO natural gas monthly ($ per mcf) | **6.27** | 7.38 | (15%) | **7.77** | 7.03 | 11% |
| Canadian / U.S. dollar exchange rate | **0.891** | 0.804 | 11% | **0.878** | 0.809 | 9% |

Oil prices have increased significantly in the second quarter of 2006 as compared to the second quarter of 2005. The West Texas Intermediate ("WTI") crude oil price increased by 33%, however this increase was not fully reflected in the Edmonton light crude oil price ("Edmonton Par") due to the 11% appreciation in value of the Canadian dollar. The Canadian dollar equivalent of WTI for the second quarter of 2006 was $79.35, $8.59 lower had the dollar not appreciated. As a result, Edmonton Par only realized a 20% increase over the same period. A similar situation occurred for the six months ended June 30, 2006 compared to the prior year as WTI increased by 30% while Edmonton Par only increased by 16%. For the six months ended June 30, 2006, the Canadian dollar equivalent of WTI was $76.41, $6.52 lower had the exchange rate not increased by 9%. In addition to the strengthening Canadian dollar, Edmonton Par was impacted by the widening differential between Edmonton Par and WTI in the first quarter. For the six months ended June 30, 2006, WTI traded at a 4% premium to Edmonton Par versus WTI and Edmonton Par trading evenly in the prior year. The combination of a strengthening Canadian dollar and the widening differential between WTI and Edmonton Par resulted in only a 16% increase in Edmonton Par over the prior year when WTI increased by 30% for the same period.

In the second quarter of 2006, prices for heavy crude oil increased to $60.59 from $39.72 over the same period in 2005, a 53% increase. As shown in the table below, Bow River differentials narrowed to 23% of Edmonton Par in the second quarter of 2006, substantially lower than the 40% differential in the prior year. The increase in the Bow River price for the six month period is not as significant as that realized for the quarter over quarter due to the Bow River differentials being 42.0% in the first quarter of 2006.

| | **2006** | | 2005 | | | | 2004 | |
|---|---|---|---|---|---|---|---|---|
| Differential Benchmarks | **Q2** | Q1 | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 |
| Bow River Blend differential to Edmonton Par | **22.9%** | 42.0% | 40.0% | 28.2% | 39.6% | 37.5% | 39.1% | 26.2% |

For the three and six months ended June 30, 2006 compared to the same period in 2005 AECO natural gas daily prices saw a decrease of 18% and 6%, respectively, while monthly prices for the same periods decreased by 15% during the quarter and saw an 11% increase during the six month period.

**Realized Commodity Prices**

The following table provides a breakdown of our 2006 and 2005 average commodity prices by product before and after realized losses on risk management contracts.

| | **Three months ended** | | | **Six months ended** | | |
|---|---|---|---|---|---|---|
| | **June 30, 2006** | June 30, 2005 | Change | **June 30, 2006** | June 30, 2005 | Change |
| Light to medium oil ($/bbl) | **65.30** | 53.49 | 22% | 59.67 | 51.68 | 15% |
| Heavy oil ($/bbl) | **56.73** | 36.04 | 57% | 45.35 | 33.79 | 34% |
| Natural gas liquids ($/bbl) | **63.35** | 47.31 | 34% | 60.26 | 41.75 | 44% |
| Natural gas ($/mcf) | **6.59** | 7.92 | (17%) | 7.23 | 7.25 | -% |
| Average realized price ($/boe) | **56.46** | 45.67 | 24% | 52.06 | 43.20 | 21% |
| Realized risk management losses ($/boe)(1) | **(4.41)** | (7.49) | (41%) | (3.25) | (6.71) | (52%) |
| Net realized price ($/boe) | **52.05** | 38.18 | 36% | 48.81 | 36.49 | 34% |

(1) Includes amounts realized on WTI, heavy price differential and foreign exchange contracts and excludes amounts realized on electricity contracts.

Our average realized prices were 24% higher before losses on risk management contracts and 36% higher after realized losses on risk management contracts for the three months ended June 30, 2006 as compared to the same period in 2005. The WTI price increased by 33% over the same periods, however, this benefit was partially offset by a stronger Canadian dollar resulting in an increase of only 20% for Edmonton Par. This is relatively consistent with the 24% increase in our average realized price for the three months ended June 30, 2006. The change in our average realized price is slightly higher than the change in Edmonton Par due to a narrowing of the Bow River differential to Edmonton Par from 40% in the second quarter of 2005 compared to 23% in the second quarter of 2006. As 37% of our total production is priced off of the Bow River stream, it is expected that our average realize price increase would be greater than the change in Edmonton Par. For the six months ended June 30, 2006, the Edmonton Par price increased by 16% and the Bow River price increased by 29%. The net result in the movement of these two benchmarks on our realized price for the six months ended June 30, 2006 over the same period in the prior year is an increase of 21% before hedging and 34% after hedging activities.

For the second quarter of 2006, our light to medium realized price increased 22% while the Edmonton Par increased by 20%, for the same period. We would expect the change in our realized light to medium price to be slightly higher as a portion of our light to medium production is sold based on the Bow River price, which increased by 53% for the same period. For the six months ended June 30, 2006, our light to medium realized price increased by 15% over the prior year while Edmonton Par increased by 16% over the same periods. Our realized price increase for the six months ended June 30, 2006 over the same period in 2005 is slightly lower than the Edmonton Par increase due again to a portion of our light to medium oil being sold at a Bow River price which traded at a 42.0% differential to Edmonton Par during the first quarter of 2006. Overall, our realized price increase for light to medium oil is consistent with the change in the benchmark prices.

Our realized heavy oil price differential to Edmonton Par for the three months ended June 30, 2006 was 28% compared to 45% for the three months ended June 30, 2005, a 17% improvement. This is expected as the majority of our heavy oil production is priced off of Bow River, which reflected a 17% narrowing to Edmonton Par from 40% in the second quarter of 2005 to 23% in the second quarter of 2006. For the six months ended June 30, 2006 our realized heavy oil differential to Edmonton Par was 38.6% compared to 46.9% for the prior period. Bow River differentials to Edmonton Par for the six months ended June 30, 2006 and 2005 were 32% and 39%, respectively. The change in our realized heavy oil differential was a narrowing of 8% compared to 7% for the benchmark due to lower blending costs in the first quarter of 2006 compared to the first quarter of 2005.

For the three months ended June 30, 2006, our realized natural gas price decreased by 17% compared to the same period in 2005 which is explained by the changes in the AECO prices. The AECO daily and monthly price decreased by 18% and 15%, respectively. With our natural gas sold approximately 85% at AECO daily, 10% at AECO Monthly and the remainder being sold to aggregators, the change in our realized natural gas price is reasonable. For the six months ended June 30, 2006 our realized natural gas price was $7.23/mcf compared to $7.25/mcf for the same period in 2005, essentially unchanged as a 6% decrease in the AECO natural gas daily price for the same period was offset by an 11% increase in the AECO natural gas monthly price.

**Sales Volumes**

The average daily sales volumes by product were as follows:

| | **Three months ended** | | | | | | |
|---|---|---|---|---|---|---|---|
| | **June 30, 2006** | | March 31, 2006 | | June 30, 2005 | | |
| | **Volume** | **Weighting** | Volume | Weighting | Volume | Weighting | % Volume 2006 to 2005 quarterly change |
| Light to medium oil (bbl/d)[1] | **28,951** | **48%** | 23,900 | 45% | 15,336 | 45% | 89% |
| Heavy oil (bbl/d) | **13,037** | **22%** | 15,182 | 29% | 13,519 | 39% | (4%) |
| Total oil (bbl/d) | **41,988** | **70%** | 39,082 | 74% | 28,855 | 84% | 46% |
| Natural gas liquids (bbl/d) | **2,016** | **3%** | 1,709 | 3% | 798 | 2% | 153% |
| Total liquids (bbl/d) | **44,004** | **73%** | 40,791 | 77% | 29,653 | 86% | 48% |
| Natural gas (mcf/d) | **96,848** | **27%** | 73,337 | 23% | 28,857 | 14% | 236% |
| Total oil equivalent (boe/d) | **60,145** | **100%** | 53,014 | 100% | 34,463 | 100% | 75% |

| | Six months ended | | | | |
|---|---|---|---|---|---|
| | **June 30, 2006** | | June 30, 2005 | | |
| | **Volume** | **Weighting** | Volume | Weighting | % Volume Change |
| Light to medium oil (bbl/d)(1) | **26,497** | **47%** | 15,474 | 44% | 71% |
| Heavy oil (bbl/d) | **14,045** | **25%** | 13,993 | 40% | -% |
| Total oil (bbl/d) | **40,542** | **72%** | 29,467 | 84% | 38% |
| Natural gas liquids (bbl/d) | **1,865** | **3%** | 789 | 2% | 136% |
| Total liquids (bbl/d) | **42,407** | **75%** | 30,256 | 86% | 40% |
| Natural gas (mcf/d) | **85,158** | **25%** | 27,990 | 14% | 204% |
| Total oil equivalent (boe/d) | **56,600** | **100%** | 34,921 | 100% | 62% |

(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), however, it benefits from a heavy oil royalty regime and therefore would be classified as heavy oil according to NI 51-101.

In the second quarter of 2006, average production was higher than the same period in 2005 due to the acquisition of Viking in February of 2006 and the Hay River properties in the third quarter of 2005. The second quarter 2006 production is more comparable to the first quarter of 2006 than the second quarter of 2005 recognizing that the first quarter reflects two months of Viking asset production as compared to three months in the second quarter of 2006.

Light to medium production is up from the first quarter of 2006 due to the additional one month of production from Viking as well as the impact of our first quarter drilling program in Hay River. Our first quarter 2006 light to medium production was negatively impacted as the maintenance turnarounds at facilities and drilling disruptions at our Hay River properties which are “winter access” only properties. The benefits of our first quarter 2006 drilling program in Hay River were realized in the second quarter of 2006. Average oil production from Hay River for the second quarter of 2006 averaged 6,041 bbl/d compared to 4,091 bbl/d in the first quarter.

Heavy oil production for the second quarter of 2006 decreased by approximately 4% compared to the second quarter of 2005 and 14% compared to the first quarter of 2006. These decreases are attributable to down time experienced in Suffield due to spring break up, surface land owner issues as well as lower production in Hayter and Killarney attributed to an extended turnaround at a partner operated processing plant. The impact of these events, coupled with normal production declines, has more than offset the additions to heavy oil production from the Viking assets. Heavy oil production for the six months ended June 30, 2006 compared to the same period in 2005 remained relatively consistent due to the downtime in Suffield, Hayter and Killarney as noted above.

Natural gas production in the second quarter of 2006 is 236% higher compared to the second quarter of 2005, primarily due to the acquisition of Viking in 2006. Production for the six months ended June 30, 2006 is 204% or 57,168 mcf/d higher than it was for the six months ended June 30, 2005. Had we acquired Viking at the beginning of 2006, our first quarter natural gas production would have been 96,570 mcf/d and comparable to the second quarter production as expected.

On July 4, 2006, a fire occurred at a third party, non-operated facility through which we process natural gas and liquids production from our Markerville area. The fire resulted in damage to a compressor, and production volumes in the area were shut-in commencing July 4, 2006. Within one week of the incident, we had redirected approximately 20% of the production to an alternate facility, but continued to have approximately 3,500 boe/d shut-in for the month of July. In early August, the operator restored the majority of its processing capabilities in Markerville, and over 85% of our shut-in volumes were restored. The balance remains shut-in at the time of writing but is expected to come back on stream through the third quarter. We maintain business interruption insurance, which compensates us for the lost cash flow after a 30 day deductible period.

Our production mix reflects the acquisition of the Viking properties and the Hay River acquisition in prior periods. Prior to these acquisitions, we were weighted 39% heavy oil with only 14% natural gas weighting. With these acquisitions, our product mix changed such that approximately 22% of our production is weighted towards heavy oil and 27% towards natural gas. With this change in product mix, we are less exposed to fluctuations in heavy oil differentials and more exposed to natural gas price volatility.

**Revenues**

| | Three months ended | | | |
|---|---|---|---|---|
| *(000)* | **June 30, 2006** | March 31, 2006 | June 30, 2005 | 2006 to 2005 Quarter Change |
| Light / medium oil sales | **$ 172,043** | $ 114,123 | $ 74,647 | 130% |
| Heavy oil sales | **67,300** | 47,987 | 44,337 | 52% |
| Natural gas sales | **58,045** | 53,444 | 20,798 | 179% |
| Natural gas liquids sales and other | **11,622** | 8,721 | 3,436 | 238% |
| Total sales revenue | **309,010** | 224,275 | 143,218 | 116% |
| Realized risk management contract losses[1] | **(24,118)** | (9,208) | (23,495) | 3% |
| **Net revenues including realized risk management contract losses** | **284,892** | 215,067 | 119,723 | 138% |
| Realized electricity price risk management contract gains | **258** | 477 | 146 | 77% |
| Unrealized risk management contracts (losses) / gains | **(115)** | (40,997) | 5,093 | (102%) |
| **Net Revenues, before royalties** | **285,035** | 174,547 | 124,962 | 128% |
| Royalties | **(51,907)** | (43,115) | (22,955) | 126% |
| **Net Revenues** | **$ 233,128** | $ 131,432 | $ 102,007 | 129% |

| | Six months ended | | |
|---|---|---|---|
| *(000)* | **June 30, 2006** | June 30, 2005 | Change |
| Light / medium oil sales | **$ 286,166** | $ 144,743 | 98% |
| Heavy oil sales | **115,287** | 85,593 | 35% |
| Natural gas sales | **111,489** | 36,743 | 203% |
| Natural gas liquids sales and other | **20,343** | 5,965 | 241% |
| Total sales revenue | **533,285** | 273,044 | 95% |
| Realized risk management contract losses[1] | **(33,326)** | (42,386) | (21%) |
| **Net revenues including realized risk management contract losses** | **499,959** | 230,658 | 117% |
| Realized electricity price risk management contract gains | **735** | 313 | 135% |
| Unrealized risk management contracts (losses) / gains | **(41,112)** | (69,576) | (41%) |
| **Net Revenues, before royalties** | **459,582** | 161,395 | 185% |
| Royalties | **(95,022)** | (42,850) | 122% |
| **Net Revenues** | **$ 364,560** | $ 118,545 | 208% |

[1] *Includes amounts realized on WTI, heavy price differential and foreign exchange contracts, and excludes amounts realized on electricity contracts.*

Our revenue is impacted by production volumes, commodity prices, and currency exchange rates. Light to medium oil sales revenue for the three months ended June 30, 2006 was $97.4 million (or 130%) higher than in the prior year as a result of a 42% favourable price variance and a 89% favourable volume variance. The favourable price variance relates to higher commodity prices and an increase in the medium to light oil component of our production mix. Favorable volume variances are primarily due to the addition of production volumes from the acquisition of Viking in 2006 and the Hay River property in the third quarter of 2005 as well as the focus of our drilling program which is intended to increase light to medium production.

Due to our recent significant property acquisitions (Viking and Hay River) it is more relevant to compare the second quarter of 2006 to the first quarter of 2006. Light to medium revenue for the second quarter of 2006 increased by $57.9 million (or 51%) over the prior quarter. This increase is attributed to a $32.2 million favourable price variance and a $25.7 million favourable volume variance. The volume variance between the first and second quarter of 2006 is attributed to the additional production from the full three months inclusion of the Viking properties as well as our first quarter drilling program and the small acquisition in Hay River.

For the six months ended June 30, 2006, our light to medium revenue increased by $141.4 million (or 98%). The increase is attributed to a $38.3 million favourable price variance and a $103.1 million favourable volume variance. With rising Edmonton Par and Bow River prices we expected that there would be a favourable price variance. Similarly, favourable volume variances are expected due to the Viking and Hay River acquisition.

Heavy oil sales for the three months ended June 30, 2006 increased $23.0 million (or 52%) compared to the same period in the prior year due to a favourable price variance of $24.5 million and an unfavourable volume variance of $1.5 million. The rising crude oil price environment, including narrowing heavy oil differentials, resulted in higher realized prices on our heavy oil. Reduced production is related to the downtime in Suffield, Killarney and Hayter during the second quarter of 2006 offsetting the additional heavy oil production from the Viking properties. Due to the same factors, a similar result is reflected in the heavy oil revenues in the second quarter of 2006 compared to the first quarter of 2006. Total revenues for this period are higher by $19.3 million (or 40%) as a result of a favourable price variance of $25.6 million and an unfavourable volume variance of $6.3 million. For the six months ended June 30, 2006 our heavy oil revenue increased by $29.7 million (or 35%) over the prior year due to a favourable price variance of $29.4 million and a favourable volume variance of $0.3 million.

Natural gas sales revenue increased by $37.2 million (or 179%) for the three months ended June 30, 2006 over the prior year due to a 57% unfavourable price variance of $11.8 million and a favourable volume variance of $49.0 million. The favourable volume variance is entirely attributed to the incremental gas production from the Viking properties acquired in February 2006. Natural gas revenues for the three months ended June 30, 2006 compared to the three months ended March 31, 2006 increased by $4.6 million (or 9%) as a result of an unfavourable price variance of $13.3 million offsetting a favourable volume variance of $17.9 million attributed to a full three months of production from the Viking assets in the second quarter as compared with only two months of production in the first quarter.

For the six months ended June 30, 2006 natural gas sales increased by $74.7 million (or 203%) over the same period in the prior year. The increase is attributed to an unfavourable price variance of $0.3 million and a favourable volume variance of $75.0 million substantially attributed to the Viking acquisition.

For the three and six months ended June 30, 2006, natural gas liquids revenues increased by $8.2 million (or 238%) and $14.4 million (or 241%), respectively, over the same periods in the prior year, with the increase generally due to a higher pricing environment and additional production volumes from the Viking properties.

**Risk Management Contracts**

Details of our risk management contracts at June 30, 2006, are included in Note 12 of the consolidated financial statements for the three and six months ended June 30, 2006.

The table below provides a summary of net gains and losses on risk management contracts:

| | **Three months ended** | | | | | |
|---|---|---|---|---|---|---|
| | **June 30, 2006** | | | | | June 30, 2005 |
| *(000s)* | Oil | Gas | Currency | Electricity | Total | Total |
| Realized (losses) / gains on risk management contracts | $(26,875) | $1,630 | $1,127 | $258 | $(23,860) | $ (23,349) |
| Unrealized (losses) / gains on risk management contracts | (4,840) | (2,839) | 6,170 | 1,361 | (148) | 8,631 |
| Amortization of deferred charges relating to risk management contracts | - | - | - | - | - | (3,983) |
| Amortization of deferred gains relating to risk management contracts | - | - | - | 33 | 33 | 445 |
| Total (losses) / gains on risk management contracts | $(31,715) | $(1,209) | $7,297 | $1,652 | $(23,975) | $ (18,256) |

| | **Six months ended** | | | | | |
|---|---|---|---|---|---|---|
| | **June 30, 2006** | | | | | June 30, 2005 |
| *(000s)* | Oil | Gas | Currency | Electricity | Total | Total |
| Realized (losses) / gains on risk management contracts | $(36,456) | $1,869 | $1,261 | $ 735 | $(32,591) | $ (42,073) |
| Unrealized (losses) / gains on risk management contracts | (44,458) | (607) | 6,170 | (2,550) | (41,445) | (62,122) |
| Amortization of deferred charges relating to risk management contracts | - | - | - | - | - | (8,344) |
| Amortization of deferred gains relating to risk management contracts | - | - | - | 333 | 333 | 890 |
| Total (losses) / gains on risk management contracts | $(80,914) | $1,262 | $7,431 | $(1,482) | $(73,703) | $ (111,649) |

Our total realized loss on oil and gas price and foreign exchange risk management contracts was $24.1 million (or $4.41 per boe) for the three months ended June 30, 2006 compared to $23.5 million (or $7.49 per boe) for the same period in 2005. For the six months ended June 30, 2006 we recorded a realized loss on oil and gas and foreign exchange risk management contracts of $33.3 million (or $3.25 per boe), a decrease of $9.1 million over the realized loss on oil and gas and foreign exchange risk management contracts for the six months ended June 30, 2005 of $42.4 million (or $6.71 per boe).

Our realized loss on oil contracts for the second quarter of 2006 was $26.9 million compared to $23.3 million in the second quarter of 2005. The increase in our loss is a result of high oil prices in the second quarter of 2006. In addition, we had heavy oil differential contracts in place in 2006, with realized losses on these contracts of $3.4 million (or $0.62 per boe) due to a significant narrowing of heavy oil differentials to 23% as compared to the contracted differentials of approximately 28-29%. For the three months ended June 30, 2005, we did not have any differential contracts in place. Since the first quarter of 2005, our risk management strategy has changed to contracts with a fixed floor with upside participation. As a result, losses on our WTI contracts remained relatively consistent at $23.5 million for the second quarter of 2006 compared to $23.3 million for the second quarter of 2005 in light of an increase in volumes hedged; total volumes hedged in the second quarter of 2005 were 24,530 bbl compared to 26,250 bbl in the second quarter of 2006.

Our total realized loss on price risk management oil contracts for the six months ended June 30, 2006 was $36.5 million compared to $43.1 million for the same period in 2005. Our realized loss in the first half of 2006 included a $7.0 million (or $0.68 per boe) gain on our heavy oil differential contracts. We did not have any heavy oil differential contracts in place in 2005. As a result, our realized losses on oil contracts decreased for the six months ended June 30, 2006 compared to 2005.

For the three and six months ended June 30, 2006, we also realized gains on our gas price risk management contracts of $1.6 million (or $0.30 per boe) and $1.9 million (or $0.18 per boe), respectively. We did not have any gas price risk management contracts in 2005.

We have also entered into risk management contracts that provide protection from rising power costs. We realized gains on these contracts of $258,000 (or $0.05 per boe) and $735,000 (or $0.07 per boe) for the three and six months ended June 30, 2006, respectively. For the same periods in 2005, our realized gain was $146,000 (or $0.05 per boe) and a loss of $313,000 (or $0.05). Additional details on these contracts is provided under the heading "Operating Expense" of this MD&A.
The unrealized losses on our risk management contracts for the three and six months ended June 30, 2006, excluding amortization of deferred gains, was $148,000 (or $0.03 per boe) and $41.4 million (or $4.05 per boe), respectively. For the three and six months ended June 30, 2005 there was a gain of $8.6 million (or $2.75 per boe) and a loss of $62.1 million (or $9.83 per boe), respectively. Collectively, our risk management contracts had an unrealized mark-to-market deficiency of $95.1 million as at June 30, 2006. The difference between this value and the mark-to-market amount of $52.6 million at December 31, 2005 is included in our unrealized loss in the six month period ended June 30, 2006. Refer to Note 12 to the consolidated financial statements for further details of the financial instruments outstanding at June 30, 2006.

Also included in our unrealized risk management contract losses is the amortization of the deferred charges and credits that were deferred when we ceased to apply hedge accounting principles. This represented a recovery of $33,000 and $333,000 of our total unrealized gains on risk management contracts for the three and six months ended June 30, 2006 and an expense of $446,000 and $890,000 for the three and six months ended June 30, 2005. These amounts are discussed further under the heading "Deferred Charges and Credits".

Subsequent to June 30, 2006, we have entered into the following contracts:

| Quantity | Type of Contract | Term | Reference |
|---|---|---|---|
| 5,000 bbl/d | Participation swap | January 2007 – December 2007 | U.S. $65.00[(a)] |
| 5,000 bbl/d | Participation swap | January 2008 – June 2008 | U.S. $65.00[(b)] |
| 25,000 mcf/d | Natural gas price collar | November 2006 – March 2007 | Cdn $7.00-12.50 |
| 4.167 MM USD/month | Foreign currency swap | January 2007-December 2007 | $1.1189 Cdn/U.S. |
| 8.333 MM USD/month | Foreign currency swap | January 2008 - June 2008 | $1.1098 Cdn/U.S. |
| 4.167 MM USD/month | Foreign currency swap | January 2007 – December 2007 | $1.1249 Cdn/U.S. |

*(a) This price is a floor. The Trust realizes this price plus 79% of the difference between the spot price and this price.*
*(b) This price is a floor. The Trust realized this price plus 67% of the difference between the spot price and this price.*

**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. In certain situations, such as with some heavy oil production, the Alberta Energy and Utilities Board grants royalty 'holidays', effectively eliminating royalties on a specific well or group of wells.

For the three and six months ended June 30, 2006, our net royalties as a percentage of gross revenue were 16.8% (16.0% - three months ended June 30, 2005) and 17.8% (15.7% - six months ended June 30, 2005), respectively, and aggregated to

$51.9 million ($23.0 million –three months ended June 30, 2005) and $95.0 million ($42.9 million – six months ended June 30, 2006), respectively. An increase in the royalty rate was expected due to the higher rates associated with the Viking assets acquired in February 2006 (as compared to Viking's history of royalty rates of approximately 18%) and the Hay River properties acquired in August 2005 (realized royalty rates of approximately 24-25%). In addition, effective April 1, 2005 a 3.6% surcharge was applied by the Saskatchewan government on gross resource revenues earned in Saskatchewan (2% for production from wells drilled subsequent to October 2002) which effect the first quarter of 2006 but not the first quarter in the prior year.

### Operating Expense

| | Three months ended | | |
|---|---|---|---|
| *($000s)* | **June 30, 2006** | March 31, 2006 | June 30, 2005 |
| Operating expense | | | |
| Power | **$ 12,227** | $ 12,028 | $ 7,585 |
| Workovers | **12,843** | 9,346 | 8,867 |
| Repairs and maintenance | **7,317** | 4,628 | 2,843 |
| Labour – internal | **5,912** | 3,933 | 1,667 |
| Processing fees | **4,774** | 4,329 | 1,422 |
| Fuel | **2,382** | 2,029 | 1,049 |
| Labour – external | **3,541** | 2,995 | 1,625 |
| Land leases and property tax | **3,781** | 4,572 | 1,647 |
| Other | **7,816** | 6,234 | 1,859 |
| Total operating expense | **60,593** | 50,094 | 28,564 |
| Realized gains on power risk management contracts | **(258)** | (477) | (146) |
| Net operating expense | **$ 60,335** | $ 49,617 | $ 28,418 |
| Transportation and marketing expense | **$ 4,065** | $ 1,623 | $ 71 |
| Net operating Expense ($/boe) | **$ 11.02** | $ 10.40 | $ 9.06 |
| Transportation and marketing expense ($/boe) | **$ 0.74** | $ 0.34 | $ 0.02 |

| | Six months ended | |
|---|---|---|
| *($000s)* | **June 30, 2006** | June 30, 2005 |
| Operating expense | | |
| Power | **$ 24,255** | $ 15,646 |
| Workovers | **22,189** | 15,862 |
| Repairs and maintenance | **11,945** | 5,287 |
| Labour – internal | **9,845** | 4,224 |
| Processing fees | **9,103** | 3,194 |
| Fuel | **4,411** | 2,340 |
| Labour – external | **6,536** | 3,499 |
| Land leases and property tax | **8,353** | 2,979 |
| Other | **14,050** | 2,706 |
| Total operating expense | **110,687** | 55,737 |
| Realized gains on power risk management contracts | **(735)** | (313) |
| Net operating expense | **$ 109,952** | $ 55,424 |
| Transportation and marketing expense | **$ 5,688** | $ 246 |
| Net operating Expense ($/boe) | **$ 10.73** | $ 8.77 |
| Transportation and marketing expense ($/boe) | **$ 0.56** | $ 0.04 |

Total operating expense increased by $32.0 million (or 112%) and $55.0 million (or 99%) respectively for the three and six months ended June 30, 2006 compared to the same periods in the prior year. For the three months ended June 30, 2006, approximately $29.6 million of the increase ($47.5 million for the six months ended June 30, 2006) is due to increased activity associated with the Viking properties acquired in February 2006 and the Hay River acquisition made in August 2005. The remainder of the increase is attributed to fuel and power cost increases, and the continued high demand for oilfield services leading to higher costs for well servicing, workovers and well maintenance. Overall, we expect higher operating costs to continue as a result of general cost pressures in the oil and natural gas industry. However, our operating expenses will benefit from our capital spending program, a portion of which is directed towards operating cost reduction initiatives such as water disposal, fluid handling and power reduction projects. With the acquisition of a private oil and gas company effective July 28, 2006, which has operating costs of less than $4.00/boe and higher levels of production, we expect our operating expenses per boe to trend lower in the second half of 2006.

Our transportation costs are primarily related to our costs of delivering natural gas to Alberta's natural gas sales hub, the AECO Storage Hub, and to a much lesser extent, our costs of trucking crude oil to pipeline receipt points.

As the addition of the Viking properties and the Hay River properties to our portfolio significantly impacts comparability between the second quarter of 2006 and the second quarter of 2005, it may be more meaningful to compare the second quarter of 2006 to the first quarter of 2006. Our second quarter of 2006 operating expenses increased by $10.5 million compared to the first quarter of 2006. The most significant portion of the increase (approximately $8.8 million) is attributable to having three full months of operating expenses attributable to the properties acquired in the Viking acquisition in the second quarter as compared to two months in the first quarter of 2006. The remainder of the increase is due to higher well servicing, workovers and well maintenance activity. In the second quarter we are not only seeing higher cost associated with services, but have more properties requiring servicing as well.

As noted, electricity costs represent a significant portion of our operating costs (approximately 20% in the second quarter of 2006 and 22% year to date) and with generally rising electricity prices, particularly in Alberta, our operating expenses can be significantly impacted. In the second quarter of 2006, electricity costs per megawatt hour ("MWh") were 4% higher than they were in the second quarter of 2005. These increases were offset by the Viking properties which have lower power usage per barrel of production, and the Hay River properties which operate using internally generated power. The combination of these two factors, as well as the impact of our fixed price electricity contracts, has resulted in a lower per boe power cost despite rising prices. For the six months ended June 30, 2006, we are seeing similar results. With a 13% increase in the per MWh cost of power we experienced a 4% decrease in our per boe power costs which is attributed to the same factors noted above. The following table details the power costs per boe before and after the impact of our hedging program.

| | Three months ended | | | | Six months ended | | |
|---|---|---|---|---|---|---|---|
| *($ per boe)* | **June 30, 2006** | March 31, 2006 | June 30, 2005 | 2006 to 2005 Quarter Change | **June 30, 2006** | June 30, 2005 | Change |
| Power costs | **$ 2.23** | $ 2.52 | $ 2.42 | (8%) | **$ 2.37** | $ 2.48 | (4%) |
| Realized gains on electricity risk management contracts | **(0.05)** | (0.10) | (0.05) | -% | **(0.07)** | (0.05) | 40% |
| Net power costs | **$ 2.18** | $ 2.42 | $ 2.37 | (8%) | **$ 2.30** | $ 2.43 | (5%) |
| Alberta Power Pool electricity price ($ per MWh) | $ 53.59 | $56.96 | $51.46 | 4% | $55.17 | $48.67 | 13% |

Approximately 65% of our estimated Alberta electricity usage is protected by fixed price purchase contracts at an average price of $51.48 per MWh through December 2006. Of our estimated 2007 and 2008 Alberta electricity usage, 52% is protected at an average price of $56.69 per MWh These contracts will help moderate the impact of future cost swings, as will capital projects undertaken in 2006 and future periods that are dedicated to increasing our power efficiency.

### Operating Netback

| | Three months ended | | Six months ended | |
|---|---|---|---|---|
| *($ per boe)* | **June 30, 2006** | June 30, 2005 | **June 30, 2006** | June 30, 2005 |
| Revenues | **$ 56.46** | $ 45.67 | **$ 52.06** | $ 43.20 |
| Realized loss on risk management contracts(1) | **(4.41)** | (7.49) | **(3.25)** | (6.71) |
| Royalties | **(9.48)** | (7.32) | **(9.28)** | (6.78) |
| As a percent of revenue | **16.8%** | 16.0% | **17.8%** | 15.7% |
| Operating expense(2) | **(11.02)** | (9.06) | **(10.73)** | (8.77) |
| Transportation expense | **(0.74)** | (0.02) | **(0.56)** | (0.04) |
| Operating netback(3) | **$ 30.81** | $ 21.78 | **$ 28.24** | $ 20.90 |

(1) Includes amounts realized on WTI, heavy price differential and foreign exchange contracts, and excludes amounts realized on electricity contracts.
(2) Includes realized gain on electricity risk management contracts of $0.05 per boe for the three months ended June 30, 2006 and 2005 and $0.07 and $0.05 for the six months ended June 30, 2006 and 2005.
(3) These are non-GAAP measures; please refer to "Non-GAAP Measures" in this MD&A.

Operating netback represents the total net realized price we receive for our production after direct costs. Our operating netback is $9.03 and $7.34 per boe higher for the three and six months ended June 30, 2006 than for the same periods of 2005. The increase is a result of higher commodity prices enabling us to realize a price per boe that is $10.79/boe ($8.86/boe for the six month period) higher, lower losses realized on our hedging program of $3.08/boe ($3.46/boe for the six month period) offset by higher royalties of $2.16/boe ($2.50/boe for the six month period) and higher operating costs (including transportation) of $2.68/boe ($2.48/boe for the six month period).

### General and Administrative (G&A) Expense

| | Three months ended | | | | Six months ended | | |
|---|---|---|---|---|---|---|---|
| *($000s except per boe)* | **June 30, 2006** | March 31, 2006 | June 30, 2005 | 2006 to 2005 Quarter Change | **June 30, 2006** | June 30, 2005 | Change |
| Cash G&A(1) | **$ 7,756** | $ 6,053 | $ 2,947 | 163% | **$ 13,809** | $ 6,196 | 123% |
| Unit based compensation expense | **757** | (241) | 3,659 | (79%) | **516** | 5,876 | (91%) |
| Total G&A | **$ 8,513** | $ 5,812 | $ 6,606 | 29% | **$ 14,325** | $ 12,075 | 19% |
| Cash G&A per boe ($/boe) | **1.42** | 1.27 | 0.94 | 51% | **1.35** | 0.98 | 38% |
| Transaction costs | | | | | | | |
| Unit based compensation expense | **330** | 8,644 | - | 100% | **8,974** | - | 100% |
| Severance and other | **-** | 3,098 | - | - | **3,098** | - | 100% |
| Total Transaction costs | **$ 330** | $ 11,742 | $ - | 100% | **$ 12,072** | $ - | 100% |

(1) Cash G&A excludes the impact of our unit based compensation expense and other one time transaction costs.

For the three months ended June 30, 2006, Cash G&A costs increased by $4.8 million (or 163%) compared to the same period in 2005. For the six months ended June 30, 2006, Cash G&A increased by $7.6 million (or 123%). The increase is attributed mainly to increased staffing levels due to the Viking acquisition. Approximately $5.1 million (or 66%) of our second quarter 2006 Cash G&A and $9.1 million (or 66%) of our six months ended June 30, 2005 Cash G&A expenses are related to salaries and other employee related costs while in the second quarter of 2005 only $1.7 million (or 58%) of our Cash G&A and $3.5 million (or 56%) of our six months ended June 30, 2006 was made up of these costs. The acquisition of Viking in February 2006 significantly increased our overall staffing levels, adding approximately 100 additional employees.

In addition, we have incurred increased costs in the second quarter associated with the work undertaken for compliance with the Sarbanes Oxley Act, investor relations costs associated an increased number of unitholders, and generally higher salaries as a result of a very competitive Calgary market. We also continue to look at potential acquisition opportunities and incur costs associated with the investigation of these opportunities which are expensed when the opportunities are abandoned.

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 based on 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 months ended June 30, 2006, including $330,000 allocated to transaction costs, was $1.1 million, consisting of $1.8 million of cash compensation, $0.9 million of unit settled compensation and a $1.6 million non-cash recovery. Our total unit based compensation expense for the six months ended June 30, 2006, including $9.0 million allocated to transaction costs, was $9.5 million, consisting of $7.0 million of cash compensation, $7.4 million of unit settled compensation and a $4.9 million non-cash recovery. A reversal of expenses is recognized in periods where our Trust Unit price decreases from the beginning of the period to the end of the period. Our opening Trust Unit market price was $33.95 at March 31, 2006, and at June 30, 2006 our Trust Unit price had decreased to $33.21. As a result, we have recorded a recovery on unexercised UARs at June 30, 2006. Our total unit based compensation expense, including that portion which has been allocated to transaction costs, decreased by $2.6 million for the three month period ended June 30, 2006 and increased by $3.6 million for the six month period ended June 30, 2006 over the same period in the prior year.

We have recorded transaction costs of $12.1 million which represent one time costs incurred as part of the acquisition of Viking. All of Harvest's outstanding UARs vested on February 3, 2006 in conjunction with the plan of arrangement. As a result, we have reflected $9.0 million, related to the additional expense incurred as a result of the accelerated vesting of our units, as a transaction cost. The remaining $3.1 million recorded as transaction costs are related to severance payments made to Harvest employees upon merging with Viking.

**Interest Expense**

| | Three months ended | | | | Six months ended | | |
|---|---|---|---|---|---|---|---|
| *($000s except per boe)* | **June 30, 2006** | March 31, 2006 | June 30, 2005 | 2006 to 2005 Quarter Change | **June 30, 2006** | June 30, 2005 | Change |
| Interest on short term debt | **$ 76** | $ 150 | $ 1,636 | (95%) | **$ 226** | $ 2,870 | (92%) |
| Amortization on deferred charges – short term debt | **11** | - | 1,242 | (99%) | **11** | 2,499 | (100%) |
| Total interest on short term debt | **87** | 150 | 2,878 | (97%) | **237** | 5,369 | (96%) |
| Interest on long-term debt | | | | | | | |
| Senior notes | **5,573** | 5,724 | 6,199 | (10%) | **11,297** | 12,186 | (7%) |
| Convertible debentures | **4,623** | 3,296 | 312 | 1380% | **7,919** | 806 | 883% |
| Bank loan | **2,937** | 1,303 | - | 100% | **4,240** | - | 100% |
| Amortization of deferred charges – long term debt | **761** | 1,434 | 396 | 92% | **2,195** | 786 | 179% |
| Total interest on long term debt | **13,894** | 11,757 | 6,907 | 101% | **25,651** | 13,778 | 86% |
| Total interest expense | **$ 13,981** | $ 11,907 | $ 9,785 | 43% | **$ 25,888** | $ 19,147 | 35% |

Interest expense for the three and six months ended June 30, 2006 was higher by $4.2 million and $6.7 million, respectively than for the same period in the prior year primarily due to additional convertible debentures outstanding in the second half of 2005, and convertible debentures assumed with our acquisition of Viking. Compared to the first quarter of 2006, the current quarter interest expense is $2.1 million higher, as a full three months of additional interest expense on bank debt and convertible debentures assumed through our merger with Viking was incurred in the second quarter.

Interest expense reflects the charges on outstanding bank debt, convertible debentures and senior notes as well as the amortization of related financing costs. After entering into a new credit facility on February 3, 2006, interest on our bank debt is levied at a floating rate based on banker's acceptances plus 65 basis points based on our Senior Debt to Earnings before Interest, Taxes, Depreciation and Amortization (EBITDA) as defined in the Senior Note agreement. Our interest expense on bank loans has increased by approximately $1.4 million and $1.6 million respectively for the three and six months ended June 30, 2006 as compared to the same period in 2005, due to our merger with Viking, when we assumed approximately $106.2 million of additional bank debt.

At June 30, 2006, we had five series of convertible debentures outstanding, including a 10.5% and 6.40% series, which were assumed in conjunction with the Viking acquisition. Details of the terms of each convertible debenture are outlined in Note 8 of the consolidated financial statements for the three months and six months ended June 30, 2006. Interest on the convertible debentures is reported based on the effective yield of the debt component of the convertible debentures. Interest expense on convertible debentures for the three months and six months ended June 30, 2006, is $4.3 million and $7.1 million higher respectively, compared to the same period in 2005, as it includes interest expense on approximately $245.5 million of additional convertible debentures that have been issued by Harvest or assumed from the merger with Viking since June 30, 2005. Though holders of the 9%, 8%, 6.5% and 10.5% convertible debenture series have continued to convert many of their convertible debentures to Harvest Trust Units, the associated reduction in interest expense is not sufficient to offset the additional interest associated with the more recently issued or assumed convertible debentures. In future quarters, interest expense on convertible debentures, not considering future conversions, should remain relatively consistent with the interest expense in the second quarter of 2006, as a full three months of interest expense on the convertible debentures assumed in the Viking's acquisition has been incurred in the quarter. During the quarter, $2.4 million of convertible debentures were converted to Trust Units ($7.2 million for the six months ended June 30, 2006).

Our U.S. dollar denominated senior notes, which bear interest at 7 7/8%, mature on October 15, 2011 and have a fourth year redemption feature, provide an offset to fluctuations in currency exchange rates. Interest expense for the three and six months ended June 30, 2006 on these notes has remained relatively consistent with the same period in 2005, with any fluctuations attributed to volatility in the Canadian dollar to U.S. dollar exchange rate.

Included in total 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 costs incurred to secure credit facilities, all totaling $1.2 million and $2.9 million, respectively, for the three and six months ended June 30, 2006 ($1.7 million and $3.4 million for the three and six months ended June 30, 2005).

**Depletion, Depreciation and Accretion Expense**

| | **Three months ended** | | | | **Six months ended** | | |
|---|---|---|---|---|---|---|---|
| *(000s except per boe)* | **June 30, 2006** | March 31, 2006 | June 30, 2005 | Change | **June 30, 2006** | June 30, 2005 | Change |
| Depletion and depreciation | **$ 88,886** | $ 77,395 | $ 32,508 | 173% | **$ 166,281** | $ 68,964 | 141% |
| Depletion of capitalized asset retirement costs | **4,230** | 4,282 | 2,554 | 66% | **8,512** | 5,370 | 59% |
| Accretion on asset retirement obligation | **4,062** | 3,648 | 2,346 | 73% | **7,710** | 4,641 | 66% |
| Total depletion, depreciation and accretion | **$ 97,178** | $ 85,325 | $ 37,408 | 160% | **$ 182,503** | $ 78,975 | 131% |
| Per boe ($/boe) | **17.76** | 17.88 | 11.93 | 49% | **17.81** | 12.49 | 43% |

Our overall depletion, depreciation and accretion (DD&A) expense for the three and six months ended June 30, 2006 is $59.8 million and $103.5 million higher compared to the same period in 2005. $27.9 million of the increase for the three months ended June 30, 2006 ($49.0 million for the six months ended June 30, 2006) is due to the incremental production from the acquisitions made in the latter half of 2005 and the merger with Viking in the first quarter of 2006 and $31.9 million of the increase for the three months ended June 30, 2006 ($54.5 million for the six months ended June 30, 2006) is due to a higher depletion rate also reflecting the Hay River and Viking acquisitions. These acquisitions have increased our overall corporate DD&A rate due to their higher cost as compared to prior property acquisitions.

**Foreign Exchange Gain**

Foreign 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 senior notes, as well as any other U.S. dollar deposits and cash balances. At June 30, 2006, the Canadian dollar strengthened against the U.S. dollar compared to December 31, 2005, and we incurred an unrealized gain on our senior notes of $11.7 million, which was partially offset by unrealized losses on U.S. dollar deposits of $0.2 million, as well as realized losses on other U.S. denominated transactions, for total foreign exchange gain of $11.5 million reported in the first six month of 2006.

**Deferred Charges and Credits**

The deferred charges balance on the balance sheet is comprised of four main components: deferred financing charges, discount on senior notes, premium on our office lease and for 2005, deferred charges related to the discontinuation of hedge accounting principles. The deferred financing charges relating to the issuance of the senior notes, convertible debentures and bank debt are amortized over the life of the corresponding debt. The following table provides a summary of the components of the deferred charges at June 30, 2006 as compared to 2005.

| *(000s)* | Financing Costs | Discount on Senior Notes | Office Leases | Discontinuation of Hedge Accounting | Total |
|---|---|---|---|---|---|
| **Balance, January 1, 2005** | **$ 12,781** | **$ 2,000** | **$ -** | **$ 10,759** | **$ 25,540** |
| Additions | 5,207 | - | - | - | 5,207 |
| Transferred to Unit issue costs on conversion of debentures | (2,071) | - | - | - | (2,071) |
| Amortization | (4,853) | (296) | - | (10,759) | (15,908) |
| **Balance, December 31, 2005** | **$ 11,064** | **$ 1,704** | **$ -** | **$ -** | **$12,768** |
| Additions | 1,129 | - | 931 | - | 2,060 |
| Transferred to Unit issue costs on conversion of debentures | (160) | - | - | - | (160) |
| Amortization | (2,206) | (148) | (93) | - | (2,447) |
| **Balance, June 30, 2006** | **$ 9,827** | **$ 1,556** | **$ 838** | **$ -** | **$12,221** |

In the first quarter of 2006, $0.9 million of deferred charges were added to our balance sheet with respect to an office lease assumed through our acquisition of Viking which had a contracted rate per square foot less than current market rates. This lease extends until February 2010 and the related deferred charge will be amortized over the remaining lease period. Additions to deferred financing costs in the first quarter of 2006 relate to the execution of our new credit agreement on February 3, 2006.

At June 30, 2006 our deferred credit balance was $1.0 million of which $65,000 related to the discontinuation of hedge accounting principles ($398,000 at December 31, 2005). This amount will be fully amortized by the end of 2006. The remaining deferred credit balance on the consolidated balance sheet includes a leasehold improvement credit of $916,000, relating to the leasehold improvement costs reimbursed by the landlord. The credit is amortized over the lease term as a reduction of rent expense.

**Goodwill**

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value for accounting purposes, of the net identifiable assets and liabilities of that acquired business. At June 30, 2006, we have recorded $656.2 million of goodwill on our balance sheet, compared with $43.8 million at December 31, 2005. In conjunction with our acquisition of Viking for total consideration of $1,975.3 million, we recorded $612.4 million of goodwill. 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.

**Future Income Tax**

For the three and six months ended June 30, 2006, we have not recorded a future income tax balance on our balance sheet as our total deductible temporary differences exceeded our taxable temporary differences such that an asset was created. As we do not expect we will be able to recover the asset, we have not recorded it on our balance sheet. For the three and six months ended June 30, 2006 we recorded a future income tax recovery of nil and $2.3 million respectively ($3.8 million and $29.8 million for the three and six months ended June 30, 2005). The significant recovery in the six months ended June 30, 2005 related to losses recorded in the corporate subsidiaries of the Trust.

**Asset Retirement Obligation (ARO)**

In connection with a property acquisition or development expenditure, 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 must be adjusted at the end of each period to reflect the passage of time as well as changes in the estimated future cash flows of the underlying obligation.

Our asset retirement obligation increased by $79.1 million in the first half of 2006 relative to December 31, 2005. As a result of the merger with Viking, we added $60.5 million to our ARO, and the remainder of the increase in the year to date is due to additions resulting from drilling activity in the first six months of the year, an increased estimate of existing liabilities, and accretion expense, offset by actual asset retirement expenditures made in the period.

**Non-Controlling Interest**

The non-controlling interest represents the value attributed to outstanding exchangeable shares of Harvest Operations. The exchangeable shares were originally issued by Harvest Operations as partial consideration for the purchase of a corporate entity in 2004. The exchangeable shares rank equally with the Trust Units and participate in distributions through an increase in the exchange ratio applied to the exchangeable shares when they are ultimately converted to Trust Units.

Under the plan of arrangement with Viking, exchangeable shareholders were able to convert their exchangeable shares of Harvest Operations into Trust Units. As a result 156,067 exchangeable shares were converted from January 1, 2006 to June 19, 2006, leaving a balance of 26,902 outstanding at June 19, 2006 compared to a balance of 182,969 at December 31, 2005.

On March 16, 2006, we announced our intent to exercise our de minimus redemption right on the remaining 26,902 exchangeable shares outstanding. As a result, each redeemed exchangeable share was purchased for a total cash payment of $1.0 million.

The net income attributed to non-controlling interest holders for three months ended June 30, 2006 was $15,000 ($120,000 for the three months ended June 30, 2005) versus a gain of $65,000 for the six months ended June 30, 2006 ($375,000 gain for the six months ended June 30, 2005).

**Liquidity and Capital Resources**

At the end of the second quarter of 2006, our bank borrowings totaled $227.5 million and we had an undrawn credit capacity of $672.5 million pursuant to a $900 million three year extendible revolving credit facility essentially unchanged from the

$201.7 million outstanding and $698.3 million available at the end of March 2006. This syndicated credit facility currently matures on February 3, 2009, if not extended prior thereto.

During the three months ended June 30, 2006, our Cash Flows totaled $147.0 million, excluding $670,000 of one time cash transactions costs, compared to $101.0 million in the first quarter of 2006 which excludes $5.1 million of one time cash transaction costs incurred in the first quarter. Distributions, net of participation in our reinvestment plans, totaled $65.9 million in the current quarter with total cash capital expenditures totaling $54.5 million resulting in excess cash of approximately $26.7 million before working capital adjustments. During the first six months of 2006, Cash Flows totaled $248.0 million (excluding one time cash transactions costs of $5.7 million) with distributions, net of proceeds from our reinvestment plan, aggregating to $111.2 million and capital spending totaling $181.1 million including $23.7 million in respect of property acquisitions within our core assets. Our working capital requirements and bank borrowings at the end of June 2006 reflect the impact of both marginally higher commodity prices and the second quarter's lower level of capital spending relative to the first quarter of 2006. These Cash Flows represent a significant increase over the $57.2 million and $109.9 million earned over the comparative three month and six month period in 2005 primarily due to the acquisition of Viking in February 2006 and the Hay River assets in August 2005 as well as increased commodity prices.

Distributions declared for the six months ended June 30, 2006 totaled $210.7 million representing 85% of Cash Flow. Of the total distributions declared, $99.5 million have been settled with Trust Units as a result of Unitholders choosing to participate in our distribution reinvestment plans, which represents a participation rate of approximately 47%, as adjusted for the one month delay between the declaration and payment of distributions.

The availability of funds under our $900 million credit facility is subject to quarterly financial covenants requiring that the Senior Debt to Cash Flow Ratio be less than 3 to 1, the Total Debt (excluding convertible debentures) to Cash Flow Ratio be less than 3.5 to 1, Senior Debt to Capitalization be less than 50% and Total Debt to Capitalization be less than 55%, all as defined in the Credit Agreement. At the end of June 2006, our Senior Debt to Cash Flow Ratio was 0.4 to 1.0, the Total Debt (excluding convertible debentures) to Cash Flow Ratio was 0.9 to 1.0, Senior Debt to Capitalization was 8% and Total Debt to Capitalization was 17%. During the first half of 2006, holders of $7,152,000 of convertible debentures elected to convert their holdings to trust units resulting in the issuance of 273,280 trust units and resulting in our total debt, including convertible debentures, being 25% of total capitalization at the end of June 2006.

On July 26, 2006, we announced a definitive agreement to acquire a private western Canadian oil and natural gas producer with an anticipated closing in mid-August for cash consideration of approximately $440 million. Concurrent with this acquisition, we entered into a further agreement to sell on a bought deal basis, subject to regulatory approval, 6,110,000 trust units at a price of $32.75 per trust unit for gross proceeds of $200.1 million to a syndicate of Canadian underwriters. In addition, the underwriters have an over allotment option for an additional 916,500 trust units for gross proceeds of $30.0 million. Subsequent to the closing of the acquisition and the equity financing, our bank debt to total capitalization and total debt (excluding convertible debentures) would be 14% and 22%, respectively. Following our announcement, the Dominion Bond Rating Service Limited ("DBRS") confirmed the STA-5 (low) rating for Harvest noting the high cost of the acquisition as reflective of a broader industry trend with more emphasis placed on probable reserves in evaluating acquisitions in a highly competitive environment. DBRS also recognized that the acquisition fits well with our existing assets providing a high degree of certainty regarding expectations of future production and that the 50:50 debt plus equity financing should result in a modest decline in our payout ratio.

Concurrent with the above acquisition, we have increased our capital expenditure program for the year to $300 million to provide for $25 million to be spent on the acquired properties over the remainder of the year and an additional $25 million relating to an update of our plans for our existing assets. With expected undrawn credit lines of more than $400 million subsequent to closing both the acquisition and equity financing, we anticipate that our liquidity will be sufficient to fund our capital spending program and our planned distributions while Unitholder participation in our distribution reinvestment plan enables us to accelerate debt repayment.

At the beginning of the quarter, our trust units were trading around $34.00 with prices reaching $35.80 by late April and closing the quarter at $33.21. The units were actively traded on the Toronto Stock Exchange as well as the New York Stock Exchange with average daily volumes of approximately 483,000 and 322,000, respectively, during the quarter. At the end of June 2006, we estimated that our foreign ownership at approximately 44% as compared to an estimated 33% at the end of the previous quarter.

### Contractual Obligations and Commitments

| | | Maturity | | | |
|---|---|---|---|---|---|
| **Annual Contractual Obligations (*000s*)** | **Total** | Less than 1 year | 1-3 years | 4-5 years | After 5 years |
| Long-term debt | **$ 506,594** | $ - | $ - | $ 227,544 | $ 279,050 |
| Interest on long-term debt[4] | **183,158** | 23,307 | 71,256 | 71,256 | 17,339 |
| Interest on convertible debentures[3] | **79,246** | 8,727 | 31,775 | 27,548 | 11,196 |
| Operating and premise leases | **14,258** | 2,103 | 7,076 | 5,079 | - |
| Capital commitments[5] | **29,058** | 17,573 | 11,485 | - | - |
| Asset retirement obligations[6] | **622,400** | 6,254 | 10,959 | 15,359 | 589,828 |
| Total | **$ 1,434,714** | $ 57,964 | $ 132,551 | $ 346,786 | $ 897,413 |

*(1) As at June 30, 2006, we had entered into physical and financial contracts for production with average deliveries of approximately 23,750 barrels of oil equivalent per day in the balance of 2006, 17,500 barrels of oil equivalent per day in 2007 and 2,500 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 12 to the consolidated financial statements for further details.*
*(2) Assumes that the outstanding convertible debentures either convert at the holders' option or are redeemed for 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 no change in bank debt from June 30, 2006 and a constant foreign exchange rate.*
*(5) Relates to drilling commitments.*
*(6 Represents the undiscounted obligation by period*

### 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.

### Capital Expenditures

| | Three months ended | | | Six months ended | | |
|---|---|---|---|---|---|---|
| *(000s)* | **June 30, 2006** | June 30, 2005 | Change | **June 30, 2006** | June 30, 2005 | Change |
| Development capital expenditures excluding acquisitions and non-cash items | **$ 54,230** | $ 26,154 | 107% | **$ 157,469** | $ 49,377 | 219% |
| Non-cash capital additions (recoveries) | **(563)** | 683 | (182%) | **173** | 1,035 | (83%) |
| Total development capital expenditures | **53,667** | 26,837 | 100% | **157,642** | 50,412 | 213% |
| Net property acquisitions | **290** | 24,971 | (99%) | **23,672** | 29,630 | (20%) |
| Total net capital asset expenditures | **$ 53,957** | $ 51,809 | 4% | **$ 181,314** | $ 80,042 | 127% |

Harvest incurred $54.2 million of expenditures, including $26.8 million on drilling activities to drill 37 gross (23.2 net) wells during the second quarter of 2006 compared to $26.2 million and 26 net wells for the same period in the prior year. The activity reflects our increased focus on internally developed projects to exploit identified opportunities on our asset base.

In the second quarter of 2006, we continued our development drilling program in Markerville, drilling 7 gross (3.4 net) wells to the Edmonton Sands and Pekisko formations. In the second quarter of 2006, we continued the drilling program we initiated in the first quarter of 2006 in South East Saskatchewan and Red Earth by drilling an additional 4 and 3 gross and net wells in those areas. We also implemented our planned drilling program in Lloyd and Suffield. Suffield is our largest single producing property and we are drilling horizontal wells into the Glauconite formations. For the wells drilled in Lloyd, South East Saskatchewan, Red Earth, and Suffield we expect production from these wells to come on in the third quarter of 2006. Two additional wells were drilled in Wainwright adding to the 12 that were drilled in the first quarter of 2006.

The $54.2 million capital spending in the second quarter includes $2.4 million spent on land acquisitions including the acquisition of 27 sections (equivalent to 17,280 gross and net acres) of oil sands leases in our Northern Alberta area, adjacent to our Red Earth property. This acquisition expands our rights in the area to include the oil sands horizon in addition to the conventional productive hydrocarbon zones, and brings our total oil sands rights to 26,200 gross and net acres. We also incurred miscellaneous capital costs in the quarter on routine optimizations and recompletions and incurred additional costs on our water handling upgrade in Suffield. These water handling upgrades will improve our ability to optimize production on both the new drilling as well as the existing wells. This upgrade is now nearly complete with the final pumping upgrade to be completed in the fall. We should begin to see the benefits in increased productive capacity and recoverable reserves of this upgrade in the area by the beginning of the fourth quarter of 2006. In the second quarter of 2006, we also incurred additional costs in Hay River relating to tying in of wells drilled in the first quarter, completions, facility modifications and servicing activities.

The following summarizes our participation in gross and net wells drilled during the second quarter of 2006:

| | Total Wells | | Successful Wells | | Abandoned Wells | |
|---|---|---|---|---|---|---|
| **Area** | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| Markerville | 7.0 | 3.4 | 7.0 | 3.4 | - | - |
| Lloyd | 3.0 | 3.0 | 3.0 | 3.0 | - | - |
| South East Saskatchewan | 4.0 | 4.0 | 4.0 | 4.0 | - | - |
| Red Earth | 3.0 | 3.0 | 3.0 | 3.0 | - | - |
| Suffield | 3.0 | 3.0 | 3.0 | 3.0 | - | - |
| Wainwright | 2.0 | 2.0 | 2.0 | 2.0 | - | - |
| Other Areas | 15.0 | 4.8 | 15.0 | 4.8 | - | - |
| Total | 37.0 | 23.2 | 37.0 | 23.2 | - | - |

The following summarizes our participation in gross and net wells drilled for the six months ended 2006:

| | Total Wells | | Successful Wells | | Abandoned Wells | |
|---|---|---|---|---|---|---|
| **Area** | **Gross[1]** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| Hay River | 25.0 | 25.0 | 25.0 | 25.0 | - | - |
| Wainwright | 14.0 | 14.0 | 14.0 | 14.0 | - | - |
| Markerville | 11.0 | 4.9 | 11.0 | 4.9 | - | - |
| South East Saskatchewan | 11.0 | 11.0 | 11.0 | 11.0 | - | - |
| Red Earth | 10.0 | 8.9 | 10.0 | 8.9 | - | - |
| Suffield | 6.0 | 6.0 | 6.0 | 6.0 | - | - |
| Lloyd | 3.0 | 3.0 | 3.0 | 3.0 | - | - |
| Other Areas | 39.0 | 19.9 | 37.0 | 18.9 | 2.0 | 1.0 |
| Total | 119.0 | 92.7 | 117.0 | 91.7 | 2.0 | 1.0 |

(1) Excludes 8 additional wells that we have an overriding royalty interest in.

**Distributions to Unitholders and Taxability**

In the second quarter of 2006, we declared distributions of $1.14 per Trust Unit ($115.9 million) to Unitholders. This represents a 90% increase in distributions declared over the $0.60 per Trust Unit declared in the second quarter of 2005. The aggregate of distributions declared during the second quarter of $115.9 million reflects an increase in distributions on a per-Trust Unit basis over 2005 as well as an increase in the number of Trust Units outstanding of approximately 58 million following the acquisition of Viking and Hay River and continued DRIP participation.

| | Three months ended | | | Six months ended | | |
|---|---|---|---|---|---|---|
| *(000s except per Trust Unit amounts)* | **June 30, 2006** | June 30, 2005 | Change | **June 30, 2006** | June 30, 2005 | Change |
| Distributions declared[(1)] | **$ 115,889** | $ 26,140 | 343% | **$ 210,701** | $ 62,266 | 238% |
| Per Trust Unit | **$ 1.14** | $ 0.60 | 90% | **$ 2.25** | $ 1.45 | 55% |
| Taxability of distributions (%) | **100%** | 100% | - | **100%** | 100% | - |
| Per Trust Unit | **$ 1.14** | $ 0.60 | 90% | **$ 2.25** | $1.45 | 55% |
| Payout ratio (%) | **79%** | 48% | 31% | **85%** | 57% | 28% |

(1) Cash flow excludes working capital changes, settlements of asset retirement obligations and one time transaction costs associated with the Viking acquisition see Non-GAAP measures.

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.

**Outlook**

Prior to inclusion of our recently announced acquisition, we anticipated our daily production would average 60,000 to 62,000 boe/day for the period from August through December 2006. For the month of July, we experienced a loss of approximately 3,500 boe/d resulting from an explosion and fire at a partner-operated gas plant that processes our Markerville production, and continue to have approximately 500 boe/d behind pipe which is expected to come on stream through the third quarter. Combining the 6,300 boe/d of production added from the acquisition for 5 months, we anticipate our 2006 annual production will average approximately 60,000 boe/d with an expected exit rate of approximately 66,000 boe/d. We anticipate that during the last half of 2006, we will continue the tie-in of our behind pipe volumes currently estimated to be approximately 1,600 boe/d.

Our operating costs for the full year 2006 are estimated to approximate $10.50 per boe considering the impact of our acquisition. The acquired properties are expected to maintain their operating cost structure of approximately $4.00 per boe and their inclusion should result in a positive impact to our operating costs. While lower power costs continue to benefit our unit operating costs, we anticipate that the impact of continuing cost pressures in the Alberta oil field service sector will be offset somewhat by the economies of scale afforded to larger operators and our efforts to manage costs.

Currently, the forward price curve for the WTI benchmark price exceeds US$75 for the balance of 2006 with the heavy oil differential expected to widen from its current level of less than 30% of the WTI price as we move through the next few months. Our oil price risk management contracts, which include upside participation, provide a floor price of approximately US$45 on 23,750 bbl/day for the balance of 2006 with the estimated forgone revenue estimated to be approximately $6.50 per bbl of oil over the period. As a result, we expect to realize approximately US$68/bbl on our portfolio of crude oil production for the balance of 2006 based on the current forward curve. In respect of natural gas prices, we have the following price risk management positions:

- 5,000 GJ/d collared July through October 2006 with a floor of $9.00 and a cap of $13.06
- 25,000 GJ/d collared July 2006 through March 2007 with a floor of $5.00 and a cap of $13.55
- 25,000 GJ/d collared November 2006 through March 2007 with a floor of $7.00 and a cap of $12.50

to provide downside price protection during the summer season with a potential modest offset during the winter season (November through March).

We have completed a detailed review of our 2006 capital spending program and have added $50 million to the previously announced $250 million capital budget, excluding acquisitions. With capital spending of $157.5 million incurred through June, we have added an additional $25 million in respect of the recently acquired properties plus an incremental $25 million as a result of updating the plans for our existing assets. In addition, we will continue to pursue incremental acquisitions/dispositions/farmouts that focus on increasing our ownership interest in existing assets while disposing of marginal interests in other properties.

We have announced a monthly distribution of $0.38 per trust unit for July, August and September and we continue to expect that provided commodity prices remain at their current levels, our payout ratio is expected to be in the 70% to 80% range for the balance of the year, with monthly distributions at $0.38 per Trust Unit. Currently, we enjoy a participation level in our distribution reinvestment plan in excess of 40% and we will use this source of funding to round out the financing of our capital spending program and direct any surplus to debt reduction.

The following table reflects sensitivities of our expected 2007 Cash Flow, including the effect of our acquisition announced on July 26, 2006 and concurrent equity financing.

| | Assumption | | Change | | Impact on Cash Flow | |
|---|---|---|---|---|---|---|
| WTI oil price ($US/bbl) | $ | 65.00 | $ | 5.00 | $ | 0.38 / Unit |
| CAD/USD exchange rate | $ | 0.85 | $ | 0.01 | $ | 0.07 / Unit |
| AECO daily natural gas price | $ | 8.00 | $ | 1.00 | $ | 0.32 / Unit |
| Interest rate on outstanding bank debt | | 5.00% | | 1.0% | $ | 0.05 / Unit |
| Liquids production volume (bbl/d) | | 46,600 | | 2,000 | $ | 0.31 / Unit |
| Natural gas production volume (mcf/d) | | 120,000 | | 5,000 | $ | 0.11 / Unit |
| Operating Expenses (per boe) | $ | 9.80 | $ | 1.00 | $ | 0.21 / Unit |

As the consolidation/rationalization of the Canadian royalty trust sector continues, we expect to be an active participant in appropriate opportunities; however, the property acquisition market in the western Canadian sedimentary basin continues to be very competitive with a modest supply of attractive opportunities. We also routinely evaluate our property portfolio and dispose of properties that are viewed as having insignificant future development potential. In addition, we intend to maintain a strong balance sheet with significant credit capacity to support a large scale acquisition. With or without further acquisitions, we will continue to develop our existing assets, a very significant resource base.

**Summary of Historical Quarterly Results**

The table and discussion below highlight our performance over the first quarter of 2006 and the preceding seven quarters on select measures.

| **Financial** | **2006** | | 2005 | | | | 2004 | |
|---|---|---|---|---|---|---|---|---|
| *($000s except where noted)* | **Q2** | Q1 | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 |
| Revenue, net of royalties | **$ 257,103** | $ 181,160 | $ 154,646 | $ 169,654 | $ 120,263 | $ 109,931 | $ 106,964 | $ 85,096 |
| Net income (loss) | **60,682** | (33,937) | 75,638 | 52,862 | 19,516 | (43,070) | 11,600 | 1,740 |
| Per Trust Unit, basic[2] | **$ 0.60** | $ (0.41) | $ 1.45 | $ 1.09 | $ 0.45 | $ (1.02) | $ 0.29 | $ 0.06 |
| Per Trust Unit, diluted[2] | **$ 0.60** | $ (0.41) | $ 1.42 | $ 1.08 | $ 0.44 | $ (1.02) | $ 0.27 | $ 0.06 |
| Cash Flows[1] | **147,010** | 100,971 | 96,431 | 103,508 | 57,217 | 52,687 | 52,870 | 41,267 |
| Per Trust Unit, basic[1] | **$ 1.45** | $ 1.23 | $ 1.84 | $ 2.14 | $ 1.32 | $ 1.25 | $ 1.31 | $ 1.42 |
| Per Trust Unit, diluted[1] | **$ 1.43** | $ 1.22 | $ 1.81 | $ 2.09 | $ 1.29 | $ 1.19 | $ 1.18 | $ 1.12 |
| Distributions per Unit, declared | **$ 1.14** | $ 1.11 | $ 1.05 | $ 0.95 | $ 0.60 | $ 0.60 | $ 0.60 | $ 0.60 |
| Total long term financial liabilities | **746,840** | 735,896 | 349,074 | 386,124 | 455,163 | 321,534 | 326,250 | 95,609 |
| Total assets | **3,455,918** | 3,470,653 | 1,308,481 | 1,327,272 | 1,117,792 | 1,079,269 | 1,050,483 | 1,070,016 |
| Total production (boe/d) | **60,145** | 53,014 | 38,834 | 37,549 | 34,463 | 35,386 | 37,215 | 24,856 |

(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 and Cash Flows have generally increased steadily over the eight quarters as shown above. The significantly higher revenue in the second quarter of 2006 over the preceding quarters is due to the incremental revenue recorded from the Viking assets acquired in February of 2006 and a rising commodity price environment.

Cash flows have also steadily risen over the same period, with marked increases in the third quarter of 2005 in which Harvest benefited from higher production from the Hay River acquisition, stronger crude oil prices and narrower heavy oil differentials early in the quarter. However, this trend did not continue into the fourth quarter of 2005 as a result of decreased commodity prices and widening heavy oil differentials, which continued into the first quarter of 2006 and also impacted Cash Flows. In the second quarter of 2006, Cash Flows were positively impacted by higher commodity prices, lower heavy oil differentials and a full quarter of production from the Viking Energy Royalty Trust assets acquired in February of 2006. The most significant increases in revenue occurred through the first and second quarter of 2006, due to unprecedented commodity prices and the impact of the Viking acquisition that occurred in the first quarter. The general increasing revenue trend since the third quarter of 2004 is also attributable to the strong commodity price environment through 2005 and into 2006.

Net income reflects both cash and non-cash items. Changes in non-cash items, including depletion, depreciation and accretion (DD&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 can cause net income to vary significantly from period to period. However, these items do not impact the Cash Flows available for distribution to Unitholders, and therefore we believe net income to be a less meaningful measure of performance for us. 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. We ceased using hedge accounting for all of our risk management contracts in October 2004 and switched to a fair value accounting methodology, which has substantially increased the volatility in our reported earnings. Due primarily to the inclusion of unrealized mark-to-market gains and losses on risk management contracts, net income (loss) has not reflected the same trend as net revenues or Cash Flows.

**Critical Accounting Policies and Critical Accounting Estimate**

Critical accounting policies and estimates are the same as those presented in our 2005 annual MD&A.

**Recent Canadian Accounting and Related Pronouncements**

In an effort to harmonize Canadian GAAP with U.S. GAAP, the Canadian Accounting Standards Board has recently issued new Handbook sections:

- 1530, Comprehensive Income;
- 3855, Financial Instruments – Recognition and Measurement;
- 3861, Financial Instruments – Disclosure and Presentation; and
- 3865, Hedges.

Under these new standards, all financial assets should be measured at fair value with the exception of loans, receivables and investments that are intended to be held to maturity and certain equity investments, which should be measured at cost. Similarly, all financial liabilities should be measured at fair value when they are either derivatives or held for trading. Gains and losses on financial instruments measured at fair value will be recognized in the income statement in the periods they arise with the exception of gains and losses arising from:

- financial assets held for sale, for which unrealized gains and losses are deferred in other comprehensive income until sold or impaired; and
- certain financial instruments that qualify for hedge accounting.

Sections 3855 and 3865 make use of the term “other comprehensive income”. Other comprehensive income comprises revenues, expenses, gains and losses that are excluded from net income. Unrealized gains and losses on qualifying hedging instruments, unrealized foreign exchange gains and losses, and unrealized gains and losses on financial instruments held for sale will be included in other comprehensive income and reclassified to net income when realized. Comprehensive income and its components will be a required disclosure under the new standard. Section 3861 addresses the presentation of financial instruments and non-financial derivatives, and identifies the information that should be disclosed about them. These standards are effective for interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. As we do not apply hedge accounting to any of our derivative instruments, we do not expect these pronouncements to have a significant impact on our consolidated financial results.

*Non-Monetary Transactions*

The AcSB has issued Section 3831, *Non-Monetary Transactions*, which replaces Section 3830, and requires all non-monetary transactions to be measured at fair value unless:

- the transaction lacks commercial substance;
- the transaction is an exchange of production or property held for sale in the ordinary course of business for production or property to be sold in the same line of business to facilitate sales to customers other than the parties to the exchange;
- neither the fair value of the assets or services received nor the fair value of the assets or services given up is reliably measurable; or
- the transaction is a non-monetary, non-reciprocal transfer to owners that represents a spin-off or other form of restructuring or liquidation.

The new requirements apply to non-monetary transactions, initiated in periods beginning on or after January 1, 2006. Earlier adoption was permitted as of the beginning of a period beginning on or after July 1, 2005. This section did not have a material impact on our results of operations or financial position.

**Operational and Other Business Risks**

Our operational and other business risks are substantially the same as those presented in our 2005 annual MD&A.

**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 managements. Cash G&A are G&A expenses excluding the effect of our unit based compensation plans.

For the three and six months ended June 30, 2006 and 2005, Cash Flows are reconciled to its closest GAAP measure, Cash Flow from operating activities, as follows:

| | **Three months ended** | | | **Six months ended** | |
|---|---|---|---|---|---|
| *($000s)* | **June 30, 2006** | March 31, 2006 | June 30, 2005 | **June 30, 2006** | June 30, 2005 |
| Cash Flow | **$ 147,010** | $ 100,971 | $ 57,217 | **$ 247,981** | $ 109,904 |
| Cash Viking transaction costs | **(670)** | (5,072) | - | **(5,742)** | - |
| Settlement of asset retirement obligations | **(625)** | (1,118) | (663) | **(1,743)** | (1,164) |
| Changes in non-cash working capital | **(10,134)** | (6,617) | (6,983) | **(16,751)** | (55,677) |
| Cash flow from operating activities | **$ 135,581** | $ 88,164 | $ 49,571 | **$ 223,745** | $ 53,063 |

**Forward-Looking Information**

This MD&A highlights significant business results and statistics from our consolidated financial statements for the three and six months ended June 30, 2006 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; 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, operating costs, commodity prices, administrative costs, commodity price risk management activity, acquisitions and dispositions, capital spending, 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 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.

## Harvest Energy Trust
## Consolidated Balance Sheets (Unaudited)

*(thousands of Canadian dollars)*

| | | June 30, 2006 | | December 31, 2005 |
|---|---|---|---|---|
| **Assets** | | | | |
| Current assets | | | | |
| Accounts receivable | **$** | **158,530** | $ | 73,766 |
| Fair value of risk management contracts *[Note 12]* | | **8,275** | | 21,231 |
| Prepaid expenses and deposits | | **6,436** | | 1,126 |
| Future income tax | | **-** | | 22,975 |
| | | **173,241** | | 119,098 |
| Deferred charges *[Note 3]* | | **12,221** | | 12,768 |
| Fair value of risk management contracts *[Note 12]* | | **10,191** | | 2,628 |
| Capital assets *[Note 4]* | | **2,604,017** | | 1,130,155 |
| Goodwill *[Note 2]* | | **656,248** | | 43,832 |
| | **$** | **3,455,918** | $ | 1,308,481 |
| **Liabilities and Unitholders' Equity** | | | | |
| Current liabilities | | | | |
| Accounts payable and accrued liabilities *[Note 5]* | **$** | **165,131** | $ | 99,576 |
| Cash distribution payable | | **38,833** | | 18,544 |
| Fair value deficiency of risk management contracts *[Note 12]* | | **69,450** | | 65,968 |
| | | **273,414** | | 184,088 |
| Bank loan *[Note 7]* | | **227,544** | | 13,869 |
| Fair value deficiency of risk management contracts *[Note 12]* | | **44,133** | | 10,449 |
| $7^{7/8}$% Senior notes | | **279,050** | | 290,750 |
| Convertible debentures *[Note 8]* | | **240,246** | | 44,455 |
| Deferred credit | | **981** | | 1,389 |
| Asset retirement obligation *[Note 6]* | | **189,841** | | 110,693 |
| Future income tax | | **-** | | 25,275 |
| Non-controlling interest *[Note 11]* | | **-** | | 3,179 |
| Unitholders' equity | | | | |
| Unitholders' capital *[Note 9]* | | **2,484,956** | | 747,312 |
| Equity component of convertible debentures *[Note 8]* | | **25,882** | | 2,639 |
| Accumulated income | | **161,854** | | 135,665 |
| Accumulated distributions | | **(471,983)** | | (125,617) |
| | | **2,200,709** | | 624,334 |
| | **$** | **3,455,918** | $ | 1,308,481 |

Commitments, contingencies, and guarantees [Note 14]
Subsequent events [Note 15]
See accompanying notes to these consolidated financial statements

## Harvest Energy Trust
## Consolidated Statements of Income (Unaudited)

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

| | **Three Months Ended June 30, 2006** | Three Months Ended June 30, 2005 | **Six Months Ended June 30, 2006** | Six Months Ended June 30, 2005 |
|---|---|---|---|---|
| **Revenue** | | | | |
| Petroleum and natural gas sales | **$ 309,010** | $ 143,218 | **$ 533,285** | $ 273,044 |
| Royalty expense | **(51,907)** | (22,955) | **(95,022)** | (42,850) |
| Risk management contracts | | | | |
| Realized net losses | **(23,860)** | (23,349) | **(32,591)** | (42,073) |
| Unrealized net gains (losses) | **(115)** | 5,093 | **(41,112)** | (69,576) |
| | **233,128** | 102,007 | **364,560** | 118,545 |
| **Expenses** | | | | |
| Operating | **60,593** | 28,564 | **110,687** | 55,737 |
| Transportation and marketing | **4,065** | 71 | **5,688** | 246 |
| General and administrative | **8,513** | 6,606 | **14,325** | 12,075 |
| Transaction charges | **330** | - | **12,072** | - |
| Interest and other financing charges on short term debt | **87** | 2,878 | **237** | 5,369 |
| Interest and other financing charges on long term debt | **13,894** | 6,907 | **25,651** | 13,778 |
| Depletion, depreciation and accretion | **97,178** | 37,408 | **182,503** | 78,975 |
| Foreign exchange (gain) loss | **(12,398)** | 3,248 | **(11,490)** | 5,367 |
| Large corporations tax and other tax | **169** | 478 | **507** | 755 |
| Future income tax recovery | **-** | (3,789) | **(2,300)** | (29,828) |
| Non-controlling interest *[Note 11]* | **15** | 120 | **(65)** | (375) |
| | **172,446** | 82,491 | **337,815** | 142,099 |
| **Net income (loss) for the period** | **60,682** | 19,516 | **26,745** | (23,554) |
| Accumulated income, beginning of period | **101,728** | (12,351) | **135,665** | 30,719 |
| Redemption of exchangeable shares | **(556)** | - | **(556)** | - |
| **Accumulated income (deficit), end of period** | **$ 161,854** | $ 7,165 | **$ 161,854** | $ 7,165 |
| Net income (loss) per Trust Unit, basic *[Note 9]* | **$ 0.60** | $ 0.45 | **$ 0.29** | $ (0.55) |
| Net income (loss) per Trust Unit, diluted *[Note 9]* | **$ 0.60** | $ 0.44 | **$ 0.29** | $ (0.56) |

See accompanying notes to these consolidated financial statements.

## Consolidated Statements of Accumulated Distributions (Unaudited)

*(thousands of Canadian dollars)*

| | **Three Months Ended June 30, 2006** | Three Months Ended June 30, 2005 | **Six Months Ended June 30, 2006** | Six Months Ended June 30, 2005 |
|---|---|---|---|---|
| Accumulated distributions, beginning of period | **$ 356,094** | $ 133,236 | $ 261,282 | $ 97,110 |
| Distributions | **115,889** | 26,140 | 210,701 | 62,266 |
| Accumulated distributions, end of period | **$ 471,983** | $ 159,376 | $ 471,983 | $ 159,376 |

## Harvest Energy Trust
## Consolidated Statements of Cash Flows (Unaudited)

*(thousands of Canadian dollars)*

| | **Three Months Ended June 30, 2006** | Three Months Ended June 30, 2005 | **Six Months Ended June 30, 2006** | Six Months Ended June 30, 2005 |
|---|---|---|---|---|
| **Cash provided by (used in)** | | | | |
| **Operating Activities** | | | | |
| Net income (loss) for the period | **$ 60,682** | $ 19,516 | **$ 26,745** | $ (23,554) |
| Items not requiring cash | | | | |
| Depletion, depreciation and accretion | **97,178** | 37,408 | **182,503** | 78,975 |
| Unrealized foreign exchange gain | **(12,037)** | 3,681 | **(11,123)** | 5,791 |
| Amortization of deferred finance charges and discount on debt | **1,150** | 1,715 | **2,877** | 3,440 |
| Unrealized loss on risk management contracts *[Note 12]* | **115** | (5,093) | **41,112** | 69,576 |
| Future income tax recovery | **-** | (3,789) | **(2,300)** | (29,828) |
| Non-controlling interest | **15** | 120 | **(65)** | (375) |
| Unit based compensation expense | **(675)** | 3,659 | **2,541** | 5,879 |
| Deferred rent expense | **(144)** | | **(144)** | |
| Amortization of office lease premium | **56** | - | **93** | - |
| Settlement of asset retirement obligations | **(625)** | (663) | **(1,743)** | (1,164) |
| Change in non-cash working capital *[Note 13]* | **(10,134)** | (6,983) | **(16,751)** | (55,677) |
| | **135,581** | 49,571 | **223,745** | 53,063 |
| **Financing Activities** | | | | |
| Issue of Trust Units, net of issue costs | **(33)** | - | **(101)** | (88) |
| Redemption of exchangeable shares | **(1,022)** | | **(1,022)** | |
| Borrowings of bank loan, net | **25,892** | 34,425 | **107,428** | 62,571 |
| Financing costs | **(964)** | (30) | **(1,129)** | (534) |
| Cash distributions | **(65,927)** | (24,582) | **(111,168)** | (45,028) |
| Change in non-cash working capital *[Note 13]* | **(5,469)** | (5,992) | **(18,770)** | (313) |
| | **(47,523)** | 3,821 | **(24,762)** | 16,608 |
| **Investing Activities** | | | | |
| Additions to capital assets | **(54,230)** | (26,154) | **(157,469)** | (49,377) |
| Property dispositions/(acquisitions) | **(290)** | (24,971) | **(23,672)** | (29,630) |
| Change in non-cash working capital *[Note 13]* | **(33,538)** | (2,267) | **(17,842)** | 9,336 |
| | **(88,058)** | (53,392) | **(198,983)** | (69,671) |
| Change in cash being cash at beginning and end of period | **$ -** | $ - | **$ -** | $ - |
| Interest paid | **$ 14,710** | $ 2,878 | **$ 17,282** | $ 4,216 |
| Large corporation tax and other tax paid | **$ 206** | $ 275 | **$ 812** | $ 346 |

See accompanying notes to these consolidated financial statements.

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

## 1. Significant Accounting Policies

These interim consolidated financial statements of Harvest Energy Trust (the "Trust" or "Harvest") have been prepared by management in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the period. In the opinion of management, these financial statements have been prepared within reasonable limits of materiality. These interim consolidated financial statements follow the same significant accounting policies as described and used in the consolidated financial statements of the Trust for the year ended December 31, 2005 and should be read in conjunction with that report.

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

## 2. Acquisitions

### *(a) Business Acquisition*

On February 3, 2006, the unitholders of the Trust and Viking Energy Royalty Trust ("Viking") voted to approve a resolution to effect the Plan of Arrangement (the "Plan of Arrangement") by which unitholders of Viking received 0.25 Harvest Trust Units for every Viking Trust Unit held, and the Trust acquired all of the assets and assumed all of the liabilities of Viking for total consideration of approximately $1,638.1 million. This amount consisted of the issuance of 46,040,788 Trust Units [Note 9(b)] at an ascribed value of $35.58 per Trust Unit, based on the weighted average trading price of the Harvest Trust Units before and after the announcement date of November 28, 2005. Pursuant to the terms and conditions of Vikings' convertible debenture indenture, Harvest's acquisition of Viking's net assets resulted in Harvest assuming the obligations of Viking's convertible debentures, including the adjustment of the conversion ratio to reflect the 0.25 Harvest Trust Unit for each Viking Trust Unit exchange ratio.

The Trust's aggregate consideration for the acquisition of Viking consists of the following:

| Consideration for the acquisition: | | |
|---|---|---|
| Ascribed value of Trust Units issued | $ | 1,638,131 |
| Bank debt assumed | | 106,247 |
| Convertible debentures assumed | | |
| Debt component | | 202,232 |
| Equity component | | 24,123 |
| Acquisition costs | | 4,600 |
| | $ | 1,975,333 |

This transaction has been accounted for using the purchase method whereby the assets acquired and the liabilities assumed are recorded at their fair values with the excess of the aggregate consideration over the fair value of the identifiable net assets allocated to goodwill. The following summarizes the allocation of the aggregate consideration for the Viking acquisition.

| Allocation of purchase price: | | Amount |
|---|---|---|
| Net working capital deficiency | $ | (31,297) |
| Capital assets | | 1,455,000 |
| Fair value deficiency of risk management contracts | | (1,224) |
| Fair value of office lease | | 931 |
| Goodwill | | 612,416 |
| Asset retirement obligation | | (60,493) |
| | $ | 1,975,333 |

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

Effective February 3, 2006, the results of Viking have been included in the consolidated financial statements.

***(b) Asset Acquisition***

On January 19, 2006, the Trust closed an asset acquisition in the Hay River and Killarney area for total cash consideration of $21.9 million.

## 3. Deferred Charges

| | | June 30, 2006 | | December 31, 2005 |
|---|---|---|---|---|
| Financing costs | **$** | **9,827** | $ | 11,064 |
| Fair value of office lease *[Note 2]* | | **838** | | - |
| Discount on Senior Notes | | **1,556** | | 1,704 |
| | **$** | **12,221** | $ | 12,768 |

## 4. Capital Assets

| **June 30, 2006** | **Cost** | **Accumulated depletion and depreciation** | **Net book value** |
|---|---|---|---|
| Petroleum and natural gas expenditures | $ 3,079,319 | $ (481,435) | $ 2,597,884 |
| Office furniture and equipment | 7,997 | (1,864) | 6,133 |
| Total | $ 3,087,316 | $ (483,299) | $ 2,604,017 |

| **December 31, 2005** | **Cost** | **Accumulated depletion and depreciation** | **Net book value** |
|---|---|---|---|
| Petroleum and natural gas expenditures | $ 1,433,284 | $ (307,384) | $ 1,125,900 |
| Office furniture and equipment | 5,377 | (1,122) | 4,255 |
| Total | $ 1,438,661 | $ (308,506) | $ 1,130,155 |

General and administrative costs of $2.9 million have been capitalized during the three month period ended June 30, 2006 (three months ended June 30, 2005- $1.6 million), of which $639,000 (three months ended June 30, 2005 - $766,000) relate to the Trust Unit incentive plan and the Unit award incentive plan.  For the six month period ended June 30, 2006 $6.8 million (six months ended June 30, 2005 - $2.8 million) of general and administrative costs have been capitalized, of which $2.7 million (six months ended June 30, 2005 - $2.7 million) relate to the Trust Unit incentive plan and the unit award incentive plan.

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

### 5. Accounts Payable and Accrued Liabilities

| | | **June 30, 2006** | | December 31, 2005 |
|---|---|---|---|---|
| Trade accounts payable | **$** | **22,049** | $ | 22,484 |
| Accrued interest | | **8,056** | | 4,959 |
| Trust Unit Incentive Plan and Unit Award Incentive Plan *[Note 10]* | | **10,164** | | 17,828 |
| Premium on price risk management contract | | **-** | | 462 |
| Other accrued liabilities | | **123,466** | | 53,223 |
| Accrued closing adjustments | | **1,050** | | - |
| Large corporation taxes payable | | **346** | | 620 |
| | **$** | **165,131** | $ | 99,576 |

### 6. Asset Retirement Obligation

The Trust's asset retirement obligation results 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. The Trust estimates the total undiscounted amount of cash flows required to settle its asset retirement obligation to be approximately $622 million which will be incurred between 2006 and 2026. The majority of the costs will be incurred between 2015 and 2026. A credit-adjusted risk-free discount rate of 8% and inflation rate of approximately 1% were used to calculate the fair value of the asset retirement obligation as at June 30, 2006.

A reconciliation of the asset retirement obligation is provided below:

| | | **Six Months ended June 30, 2006** | | Year ended December 31, 2005 |
|---|---|---|---|---|
| Balance, beginning of period | **$** | **110,693** | $ | 90,085 |
| Incurred on acquisition of Viking | | **60,493** | | - |
| Liabilities incurred | | **515** | | 7,328 |
| Revision of estimates | | **12,173** | | 8,656 |
| Liabilities settled | | **(1,743)** | | (4,146) |
| Accretion expense | | **7,710** | | 8,770 |
| Balance, end of period | **$** | **189,841** | $ | 110,693 |

### 7. Bank Loan

The Trust entered into a new credit facility agreement on February 3, 2006, that increased its borrowing capacity from $400 million to $750 million. At March 31, 2006, the Trust completed a secondary syndication of its credit facility resulting in a broadening of its banking group and an increase in its three year extendible revolving credit facility to $900 million.

At June 30, 2006, the Trust had $227.5 million drawn under a $900 million three year extendible revolving credit facility. With the consent of the lenders, the facility may be extended on an annual basis for an additional 364 days. The facility is secured by a $1.5 billion first floating charge over all of the assets of the operating subsidiaries and a guarantee from the Trust. Amounts borrowed under this facility bear interest at a floating rate based on bankers acceptances plus 65 basis points to 115 basis points depending on the Trust's Senior Debt to Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) Ratio as defined in the Credit Agreement. Availability under this facility is subject to quarterly financial covenants requiring that the Senior Debt to EBITDA Ratio is less than 3 to 1, the Total Debt to EBITDA Ratio is less than 3.5 to 1, Senior Debt to Capitalization Ratio is less than 50% and Total Debt to Capitalization Ratio is less than 55%, all as defined in the Credit Agreement.

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

## 8. Convertible Debentures

The Trust has issued three series of unsecured subordinated debentures and has assumed two additional series as part of the Viking acquisition [Note 2]. The two additional series of debentures assumed in the Viking acquisition have the same general terms as the three series issued by Harvest, the details of which have been outlined in our December 31, 2005 annual financial statements.

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

| Issue date | Interest rate | Original face value (millions) | Conversion price / Trust Unit | Maturity | First redemption period | Second redemption period |
|---|---|---|---|---|---|---|
| Jan 29, 2004 | 9% | $ 60 | $ 13.85 | May 31, 2009 | Jun. 1/07-May 31/08 | Jun. 1/08-May. 30/09 |
| Aug 10, 2004 | 8% | $ 100 | $ 16.07 | Sept. 30, 2009 | Oct. 1/07-Sept. 30/08 | Oct. 1/08-Sept. 29/09 |
| Aug 2, 2005 | 6.5% | $ 75 | $ 31.00 | Dec. 31, 2010 | Jan. 1/09-Dec. 31/09 | Jan. 1/10-Dec. 30/10 |
| Feb. 3, 2006 | 10.5% | $ 35(2) | $ 29.00 | Jan.31, 2008 | Feb. 1/06-Jan. 31/07 | Feb. 1/07-Jan. 30/08 |
| Feb. 3, 2006 | 6.40%(1) | $ 175(2) | $ 46.00 | Oct. 31, 2012 | Nov. 1/08-Oct. 31/09 | Nov. 1/09-Oct. 31/10 |

(1) This series of convertible debentures may also be redeemed by the Trust at a price of $1,000 per debenture on or after November 1, 2009 until maturity.
(2) The fair value, including the equity component, of the 10.5% convertible debentures and the 6.40% convertible debentures at acquisition was $44.8 million and $181.5 million, respectively.

The following table summarizes the issuance and subsequent conversions of the convertible debentures:

| | 9% Series | 8% Series | 6.5% Series | 10.5% Series | 6.40% Series | Total |
|---|---|---|---|---|---|---|
| As at December 31, 2004 | $ 10,698 | $ 15,052 | $ - | $ - | $ - | $ 25,750 |
| August 2, 2005 issuance | - | - | 75,000 | - | - | 75,000 |
| Portion allocated to equity | - | - | (4,932) | | | (4,932) |
| Accretion of non-cash interest expense | - | 11 | 228 | - | - | 239 |
| Converted into Trust Units | (8,921) | (11,299) | (31,382) | - | - | (51,602) |
| As at December 31, 2005 | 1,777 | 3,764 | 38,914 | - | - | 44,455 |
| February 3, 2006 assumption | - | - | - | 44,822 | 181,533 | 226,355 |
| Portion allocated to equity | - | - | - | (9,301) | (14,822) | (24,123) |
| Accretion of non-cash interest expense (premium) | | 2 | 199 | (79) | 400 | 522 |
| Converted into Trust Units | (318) | (818) | (3,330) | (2,478) | (19) | (6,963) |
| **As at June 30, 2006** | $ 1,459 | $ 2,948 | $ 35,783 | $ 32,964 | $ 167,092 | $ 240,246 |

**Number of Debentures**

| | 9% Series | 8% Series | 6.5% Series | 10.5% Series | 6.40% Series | Total |
|---|---|---|---|---|---|---|
| Number outstanding at December 31, 2004 | 10,700 | 15,159 | - | - | - | 25,859 |
| August 2, 2005 issuance | - | - | 75,000 | - | - | 75,000 |
| Converted into Trust Units | (8,923) | (11,373) | (33,527) | - | - | (53,823) |
| Outstanding at December 31, 2005 | 1,777 | 3,786 | 41,473 | - | - | 47,036 |
| February 3, 2006 assumption | - | - | - | 35,058 | 174,965 | 210,023 |
| Converted into Trust Units | (318) | (823) | (3,544) | (2,447) | (20) | (7,152) |
| **Outstanding at June 30, 2006** | 1,459 | 2,963 | 37,929 | 32,611 | 174,945 | 249,907 |

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

The following table summarizes the reclassification of the equity component of convertible debentures to Unitholders' equity:

| | 9% Series Equity Value | 8% Series Equity Value | 6.5% Series Equity Value | 10.5% Series Equity Value | 6.40% Series Equity Value | Total |
|---|---|---|---|---|---|---|
| As at December 31, 2004 | $ 3 | $ 113 | $ - | $ - | $ - | $ 116 |
| August 2, 2005 issuance, net | - | - | 4,720 | - | - | 4,720 |
| Converted into Trust Units, net | (3) | (85) | (2,109) | - | - | (2,197) |
| As at December 31, 2005 | - | 28 | 2,611 | - | - | 2,639 |
| February 3, 2006 assumption | - | - | - | 9,301 | 14,822 | 24,123 |
| Converted into Trust Units, net | - | (6) | (223) | (649) | (2) | (880) |
| **As at June 30, 2006** | **$ -** | **$ 22** | **$ 2,388** | **$ 8,652** | **$ 14,820** | **$ 25,882** |

**9. Unitholders' Capital**

***(a) Authorized***
The authorized capital consists of an unlimited number of Trust Units.

***(b) Issued***

| | Number of Units | Amount |
|---|---|---|
| **As at December 31, 2004** | **41,788,500** | $ 465,524 |
| Conversion of subscription receipts | 6,505,600 | 175,001 |
| Convertible debenture conversions-9% series | 643,133 | 8,924 |
| Convertible debenture conversions-8% series | 703,976 | 11,383 |
| Convertible debenture conversion-6.5% series | 1,081,497 | 33,585 |
| Exchangeable share retraction *[Note 11]* | 299,123 | 3,865 |
| Distribution reinvestment plan issuance | 1,167,109 | 36,217 |
| Special distribution | 465,285 | 10,678 |
| Exercise of unit appreciation rights and other | 328,344 | 12,084 |
| Issue costs | - | (9,949) |
| **As at December 31, 2005** | **52,982,567** | $ 747,312 |
| Issued in exchange for assets of Viking *[Note2(a)]* | 46,040,788 | 1,638,131 |
| Convertible debenture conversions-9% series | 22,957 | 318 |
| Convertible debenture conversions-8% series | 51,205 | 824 |
| Convertible debenture conversions-6.5% series | 114,313 | 3,563 |
| Convertible debenture conversions-10.5% series | 84,371 | 3,127 |
| Convertible debenture conversions-6.40% series | 434 | 21 |
| Exchangeable share retraction *[Note 11]* | 184,809 | 2,648 |
| Distribution reinvestment plans | 2,442,213 | 79,253 |
| Exercise of unit appreciation rights | 293,334 | 10,284 |
| Issue costs | - | (525) |
| **As at June 30, 2006** | 102,216,991 | $ 2,484,956 |

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

### *(c) Per Trust Unit Information*

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

| *Net income adjustments* | **Three Months ended June 30, 2006** | **Three Months ended June 30, 2005** | **Six Months ended June 30, 2006** | **Six Months ended June 30, 2005** |
|---|---|---|---|---|
| Net income (loss), basic | $ 60,682 | $ 19,516 | $ 26,745 | $ (23,554) |
| Non-controlling interest | 15 | - | (65) | (375) |
| Interest on convertible debentures | 825 | - | - | - |
| Net income (loss), diluted[1] | $ 61,522 | $ 19,516 | $ 26,680 | $ (23,929) |

| *Weighted average Trust Units adjustments* | **Three Months ended June 30, 2006** | **Three Months ended June 30, 2005** | **Six Months ended June 30, 2006** | **Six Months ended June 30, 2005** |
|---|---|---|---|---|
| **Number of Units** | | | | |
| Weighted average Trust Units outstanding, basic | 101,426,503 | 43,327,132 | 91,920,385 | 42,733,954 |
| Effect of convertible debentures | 1,527,476 | - | - | - |
| Effect of exchangeable shares | 28,480 | - | 64,113 | 326,473 |
| Effect of unit appreciation rights | 209,575 | 926,497 | 168,348 | - |
| Weighted average Trust Units outstanding, diluted[2] | 103,192,034 | 44,253,629 | 92,152,846 | 43,060,427 |

(1) Net income, diluted excludes the impact of the conversions of certain of the convertible debentures for the three month and six month period ended June 30, 2006, of $3,979,000 and $7,919,000, respectively (three and six months ended June 30, 2005 - $321,000 and $806,000), as the impact was anti-dilutive. For the three month period ended June 30, 2005 diluted income excludes $120,000 of net income attributed to non-controlling interest holders of $120,000 because the impact was anti-dilutive.

(2) Weighted average Trust Units outstanding, diluted for the three and six months ended June 30, 2006, does not include the impact of the units related to certain of the convertible debentures of 4,942,459 and 6,526,241, respectively (three and six months ended June 30, 2005 – 182,173 and 1,280,324, respectively), as the impact was anti-dilutive. The impact of the Trust Unit incentive plans of 812,924 for the six months ended June 30, 2005 has also been excluded as the impact would be anti-dilutive. The impact of the exchangeable shares of 262,224 for the three months ended June 30, 2005 has also been excluded as it would be anti-dilutive.

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

## 10. Employee Unit Incentive Plans

*Trust Unit Rights Incentive Plan*
As at June 30, 2006, a total of 2,096,325 (1,305,143 – December 31, 2005) Unit Appreciation Rights were outstanding under the Trust Unit Incentive Plan at an average exercise price of $31.88 ($16.73 – December 31, 2005).

The following summarizes the Trust Units reserved for issuance under the Trust Unit incentive plan:

| | **Six Months ended June 30, 2006** | | | Year ended December 31, 2005 | | |
|---|---|---|---|---|---|---|
| | **Unit Appreciation Rights** | | **Weighted Average Exercise Price** | **Unit Appreciation Rights** | | **Weighted Average Exercise Price** |
| Outstanding beginning of period | 1,305,143 | $ | 19.72 | 1,117,725 | $ | 11.92 |
| Granted | 1,956,500 | | 36.92 | 793,325 | | 26.69 |
| Exercised | (871,318) | | 18.74 | (420,157) | | 9.49 |
| Cancelled | (294,000) | | 37.40 | (185,750) | | 25.70 |
| Outstanding before exercise price reductions | 2,096,325 | | 33.70 | 1,305,143 | | 19.72 |
| Exercise price reductions | - | | (1.82) | - | | (2.99) |
| Outstanding, end of period | 2,096,325 | $ | 31.88 | 1,305,143 | $ | 16.73 |
| Exercisable before exercise price reductions | 433,825 | $ | 21.70 | 109,068 | $ | 13.56 |
| Exercise price reductions | - | | (4.30) | - | | (4.04) |
| | 433,825 | $ | 17.40 | 109,068 | $ | 9.52 |

The following table summarizes information about Unit appreciation rights outstanding at June 30, 2006.

| | | **Outstanding** | | | | **Exercisable** | | |
|---|---|---|---|---|---|---|---|---|
| **Exercise Price before price reductions** | **Exercise Price net of price reductions** | **At June 30, 2006** | | **Exercise Price net of price reductions[(a)]** | **Remaining Contractual Life [(a)]** | **At June 30, 2006** | | **Exercise Price net of price reductions [(a)]** |
| $8.00 - $10.21 | $1.10 - $3.78 | 12,500 | $ | 3.78 | 2.0 | 12,500 | $ | 3.78 |
| $10.30 - $13.15 | $3.90 - $7.50 | 61,650 | | 4.82 | 2.0 | 61,650 | | 4.82 |
| $13.35 - $17.85 | $7.89 - $14.07 | 92,075 | | 10.33 | 3.0 | 92,075 | | 10.33 |
| $18.90 - $22.97 | $14.42-$21.80 | 185,300 | | 20.08 | 3.7 | 185,300 | | 20.08 |
| $28.90 - $37.56 | $24.28-$37.09 | 1,744,800 | | 35.43 | 4.6 | 82,300 | | 30.73 |
| $8.00 - $37.56 | $1.10 - $37.09 | 2,096,325 | $ | 31.88 | 4.4 | 433,825 | $ | 17.40 |

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

*Unit Award Incentive Plan*
At June 30, 2006, 180,807 Units were outstanding under the Unit Award Incentive Plan.

Upon completion of the Plan of Arrangement with Viking [Note 2], Unitholders approved the issuance of up to 0.5% of outstanding Trust Units under the Unit award plan.

| **Number** | **Six Months ended June 30, 2006** | Year ended December 31, 2005 |
|---|---|---|
| Outstanding, beginning of period | **35,365** | 10,662 |
| Granted | **181,079** | 23,466 |
| Adjusted for distributions | **13,136** | 1,237 |
| Exercised | **(28,508)** | - |
| Cancelled | **(20,265)** | - |
| Outstanding, end of period | **180,807** | 35,365 |

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

Upon closing of the Plan of Arrangement with Viking [Note 2] all awards and rights issued under the Trusts' employee unit incentive plans vested. Subsequent to closing additional rights and awards were issued under both plans.

The Trust has recognized compensation expense of $1.1 million and $9.5 million for the three and six months ended June 30, 2006 respectively ($3.8 million and $6.1 million – three and six months ended June 30, 2005 respectively) , including a non cash compensation recovery of $675,000 and an expense of $2.5 million for the three and six months ended June 30, 2006, respectively ($3.7 million and $5.9 million – three and six months ended June 30, 2005 respectively), related to the Trust Unit Incentive Plan and the Unit award plan. Recoveries occur when the Trust Unit market price decreases below the previous measurement date.

Of the total compensation expense for the three and six months ended June 30, 2006, $330,000 and $9.0 million, respectively, have been recorded within transaction costs, with the remaining recorded as part of general and administrative expenses.

The compensation expense related to the transaction with Viking, was measured based on the Trust Unit price on February 3, 2006, the effective date of the Plan of Arrangement.

## 11. Exchangeable Shares

***(a) Authorized***

Harvest Operations Corp., a subsidiary of the Trust, is authorized to issue an unlimited number of exchangeable shares without nominal or par value.

***(b) Issued***

| **Exchangeable shares, series 1** | **Six Months ended June 30, 2006** | Year ended December 31, 2005 |
|---|---|---|
| Outstanding, beginning of period | **182,969** | 455,547 |
| Shareholder retractions | **(156,067)** | (272,578) |
| Issuer redemption | **(26,902)** | - |
| Outstanding , end of period | **-** | 182,969 |
| Exchange ratio | **-** | 1.17475 |

On March 16, 2006, the Trust elected to exercise its deminimus redemption right to redeem all of the exchangeable shares outstanding. On June 20, 2006 the redemption was completed.

***(c) Non-controlling interest***

The following is a summary of the non-controlling interest:

| | **Six Months ended June 30, 2006** | Year ended December 31, 2005 |
|---|---|---|
| Non-controlling interest, beginning of period | **$ 3,179** | $ 6,895 |
| Exchanged for Trust Units | **(2,648)** | (3,865) |
| Redeemed for cash | **(1,022)** | - |
| Excess of redemption price over cost, accumulated income | **556** | - |
| Current period income (loss) attributable to non-controlling interest | **(65)** | 149 |
| **Non-controlling interest, end of period** | **$ -** | $ 3,179 |
| **Accumulated income attributed to non-controlling interest** | **$ 865** | $ 374 |

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

**12. Financial Instruments and risk management contracts**

The Trust is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations as outlined in the annual consolidated financial statements for the year ended December 31, 2005 and 2004.

The following is a summary of Harvest's risk management contracts outstanding, along with their fair value at June 30, 2006.

| Quantity | Type of Contract | Term | Reference | Fair value |
|---|---|---|---|---|
| 8,750 bbl/d | Participation swap | July – December 2006 | U.S$38.16[(a)] | $ (33,035) |
| 5,000 bbl/d | Participation swap | July – December 2006 | U.S$45.17[(a)] | (15,335) |
| 5,000 bbl/d | Participating swap | July 2006 – June 2007 | U.S.$49.03[(b)] | (13,046) |
| 5,000 bbl/d | Indexed put contract – bought put | July – December 2006 | U.S.$55.00[(c)] | 93 |
| 2,500 bbl/d | Indexed put contract – sold call | July – December 2006 | U.S.$55.00[(c)] | (10,420) |
| 2,500 bbl/d | Indexed put contract – bought call | July – December 2006 | U.S.$65.00[(c)] | 5,644 |
| 2,500 bbl/d | Indexed put contract – sold call | July – December 2006 | U.S.$70.00[(c)] | (3,543) |
| 2,500 bbl/d | Indexed put contract – bought call | July – December 2006 | U.S.$83.00[(c)] | 715 |
| 200 mcf/d | Fixed price - natural gas contract | July 2006 – December 2006 | Cdn.$5.35[(d)] | (224) |
| 76 mcf/d | Fixed price – natural gas contract | July 2006 – June 2007 | Cdn.$2.23-$2.28[(d)] | (146) |
| 4,000 bbl/d | Differential swap – Bow River | July – December 2006 | 29.58% | (153) |
| **Total current portion of fair value deficiency** | | | | **$ (69,450)** |

| Quantity | Type of Contract | Term | Reference | Fair value |
|---|---|---|---|---|
| 10,000 bbl/d | Participating swap | January – December 2007 | U.S.$55.00[(e)] | (23,861) |
| 5,000 bbl/d | Participating swap | January – December 2007 | U.S.$60.00[(f)] | (4,149) |
| 5,000 bbl/d | Participating swap | January – June 2008 | U.S.$55.00[(g)] | (1,802) |
| 5,000 bbl/d | Indexed put contract – bought put | January – December 2007 | U.S.$50.00[(c)] | 1,326 |
| 2,500 bbl/d | Indexed put contract – sold call | January – December 2007 | U.S.$50.00[(c)] | (25,637) |
| 2,500 bbl/d | Indexed put contract – bought call | January – December 2007 | U.S.$60.00[(c)] | 17,354 |
| 2,500 bbl/d | Indexed put contract – sold call | January – December 2007 | U.S.$70.00[(c)] | (10,363) |
| 2,500 bbl/d | Indexed put contract – bought call | January – December 2007 | U.S.$83.00[(c)] | 4,380 |
| 200 Mcf/d | Fixed price – natural gas contract | January 2007 – December 2008 | Cdn. $5.35[(d)] | (1,161) |
| 76 Mcf/d | Fixed price – natural gas contract | July 2007 - October 2008 | Cdn. $2.28-$2.34[(d)] | (220) |
| **Total long-term portion of fair value deficiency** | | | | **$ (44,133)** |

*(a) This price is a floor. The Trust realizes this price plus 50% of the difference between spot price and this price.*
*(b) This price is a floor. The Trust realizes this price plus 75% of the difference between spot price and this price.*
*(c) Each group of a puts and call 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.*
*(d) This contract contains an annual escalation factor such that the fixed price is adjusted each year.*
*(e) This price is a floor. The Trust realizes this price plus 67% of the difference between spot price and this price.*
*(f) This price is a floor. The Trust realizes this price plus 77% of the difference between spot price and this price.*
*(g) This price is a floor. The Trust realizes this price plus 80% of the difference between spot price and this price.*

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

| Quantity | Type of Contract | Term | Reference | Fair value |
|---|---|---|---|---|
| 5,000 bbl/d | Differential swap – Bow River | July – December 2006 | 27.50% | 1,428 |
| 1,000 bbl/d | Differential swap – Wainwright | July - December 2006 | 29.58% | 1,294 |
| 1,000 bbl/d | Differential swap – Wainwright | July 2006 – April 2007 | 27.70% | 546 |
| 5,000 GJ/d | Natural gas price collar contract | July - October 2006 | Cdn$9.00-$13.06 | 2,192 |
| 25,000 GJ/d | Natural gas price collar contract | June 2006 – March 2007 | Cdn$5.00-$13.55 | - |
| 45 MWH | Electricity price swap contracts | July – December 2006 | Cdn $51.48 | 2,637 |
| US$20 million | Foreign currency call | June – July 2006 | 1.1244 Cdn/US | 178 |
| **Total current portion of fair value** | | | | **$ 8,275** |
| 35 MWH | Electricity price swap contracts | January – December 2007 | Cdn $56.69 | 2,473 |
| 35 MWH | Electricity price swap contracts | January – December 2008 | Cdn $56.69 | 1,726 |
| 417,700 USD/month | Foreign currency swap | January – December 2007 | 1.14 Cdn/US | 5,992 |
| **Total long-term portion fair value** | | | | **$ 10,191** |

At June 30, 2006, the net unrealized loss position reflected on the balance sheet for all the risk management contracts outstanding at that date was approximately $95.1 million ($52.6 million – December 31, 2005).

For the three and six months ended June 30, 2006, the total unrealized loss (gain) recognized in the consolidated statement of income, including amortization of deferred charges and gains, was $115,000 and $41.1 million ($(5.1) million and $69.6 million – three and six months ended June 30, 2005 respectively). The realized gains and losses on all risk management contracts are included in the period in which they are incurred.

## 13. Change in Non-Cash Working Capital

| | **Three Months ended June 30, 2006** | Three Months ended June 30, 2005 | **Six Months ended June 30, 2006** | Six Months ended June 30, 2005 |
|---|---|---|---|---|
| Changes in non-cash working capital items: | | | | |
| Accounts receivable | **$ (18,847)** | $ (4,653) | **$ (9,921)** | $ (22,301) |
| Prepaid expenses and deposits | **770** | (6,061) | **(1,063)** | (42,915) |
| Current portion of risk management contracts assets | **1,038** | (4,227) | **12,956** | (948) |
| Current portion of future income tax asset | **-** | - | **22,975** | - |
| Accounts payable and accrued liabilities | **(32,957)** | (101) | **(22,965)** | 25,421 |
| Cash distribution payable | **631** | 224 | **(1,578)** | 396 |
| Current portion of risk management contracts liability | **(13,628)** | (16,976) | **2,617** | 10,364 |
| | **(62,993)** | (31,794) | **3,021** | (29,983) |
| Changes relating to operating activities | **(10,134)** | (6,983) | **(16,751)** | (55,677) |
| Changes relating to financing activities | **(5,469)** | (5,992) | **(18,770)** | (313) |
| Changes relating to investing activities | **(33,538)** | (2,267) | **(17,842)** | 9,336 |
| Add: Non cash changes | **(13,852)** | (16,552) | **56,384** | 16,671 |
| | **$ (62,993)** | $ (31,794) | **3,021** | (29,983) |

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

### 14. Commitments, Contingencies and Guarantees

The Trust has letters of credit outstanding in the amount of approximately $8.2 million primarily provided to electricity infrastructure providers. These letters are provided by Harvest Operations' lenders pursuant to the secured senior credit agreement [Note 7]. These letters expire between April 30, 2006 and December 31, 2006, and are expected to be renewed as required.

The following is a summary of the Trust's contractual obligations and commitments as at June 30, 2006:

| | Remaining Payments Due by Period | | | | | | |
|---|---|---|---|---|---|---|---|
| | **2006** | **2007** | **2008** | **2009** | **2010** | **Thereafter** | **Total** |
| Debt repayments [(1)] | $ - | $ - | $ - | $ 227,544 | $ - | $ 279,050 | $ 506,594 |
| Capital commitments | 17,573 | 8,605 | 2,880 | - | - | - | 29,058 |
| Operating leases[(2)] | 2,103 | 3,570 | 3,506 | 3,506 | 1,573 | - | 14,258 |
| Total contractual obligations | $ 19,676 | $ 12,175 | $ 6,386 | $ 231,050 | $ 1,573 | $ 279,050 | $ 549,910 |

*(1) Assumes that the outstanding convertible debentures either convert at the holders' option for Units or are redeemed for Units at the Trust's option.*
*(2) Relating to building and automobile leases.*

### 15. Subsequent Events

On July 12, 2006, the Board of Directors of Harvest Operations Corp. approved the monthly cash distributions for July, August, and September of $0.38 per Trust Unit, for total distributions before the distribution reinvestment plan of approximately $116 million.

On July 26, 2006, the Trust entered into a definitive agreement to purchase all of the issued and outstanding shares of a private Western Canadian oil and natural gas producer for $440 million, plus adjustments, with closing anticipated in mid August. The definitive agreement was entered into by shareholders owning substantially all of the issued and outstanding shares, which irrevocably transferred control of the company to the Trust, subject to only conditions that are routine procedures for a transaction of this nature. As such, in accordance with Emerging Issues Committee Abstract 119, the Trust will account for the acquisition at the effective date of July 28, 2006. The purchase will be financed with proceeds from an issuance of trust units, as discussed below, and the Trust's existing credit facilities.

In connection with the acquisition, the Trust has entered into an agreement to sell on a bought deal basis 6,110,000 Trust Units for gross proceeds of $200 million. The Trust granted the underwriters the Over-Allotment Option, which was exercised, to purchase an additional 916,500 Trust Units at the same offering price. Total gross proceeds to the Trust will be approximately $230 million. Closing is expected to occur on or about August 17, 2006.

### 16. Comparatives

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